Stage 03 Workgroup Report	At what stage is this document in the process?

CMP281: 'Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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

Purpose of Modification: CMP281 seeks to remove liability from storage facilities for Balancing Services Use of System (BSUoS) charges on imports.

This document contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal, the responses to the Workgroup Consultation which closed on 12 November 2018 the voting of the Workgroup held on 18 June 2019 and the Workgroup's final conclusions.

Medium Impact:

National Grid Electricity System Operator: Changes will be required to the BSUoS billing systems to tag out the appropriate metered import volumes for the purpose of the BSUoS charging base.

Low Impact:

Suppliers: The reduced recovery of BSUoS charges from generator parties, including storage facilities, will need to be recovered from the balance of parties liable to BSUoS. The Proposer estimates the impact to be small; In 2016/17 and 2017/18 pumped storage facilities paid £12.4m and £12.3m BSUoS on their imports. The increase in charges recovered from other Users would have amounted to £0.02/MWh (0.8%) each of these years.

The Workgroup concludes:

All Workgroup Members concluded that the Original Proposal facilitates the Applicable CUSC Objectives better than the baseline.

Contents

Timetable

The Code Administrator recommends the following timetable:

Workgroup Report presented to Panel	28 June 2019
Code Administration Consultation Report issued to the Industry	1 July 2019
Draft Final Modification Report presented to Panel	21 August 2019
Modification Panel decision	30 August 2019
Final Modification Report issued to Authority (25 WD)	9 September 2019
Indicative Decision Date	10 October 2019
Decision implemented in CUSC	1 April 2020

Any questions?

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1 About this document

This document is the Workgroup Report which contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal. In addition, it contains the responses to the Workgroup Consultation, which closed on 12 November 2018 and the voting of the Workgroup held on 18 June 2019.

CMP281 was proposed by Scottish Power and was submitted to the CUSC Modifications Panel for its consideration on 26 June 2017. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The modification was adopted by ENGIE in November 2018.

CMP281 aims to remove liability from storage facilities for Balancing Services Use of System (BSUoS) charges on imports. The Workgroup consulted on this Modification and a total of 12 responses were received. These responses can be views in Section 3 of this Report.

Workgroup Conclusions

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

Terms of Reference

Specific Area	Location in the report
a). Consider co-location of generation and storage assets	Section 4, Page 19
b) Consider the practical implications of solution e.g. that all metered data is available to National Grid to support the proposed solution	Throughout Section 4
c) Consider the impacts on RCRC and BSC arrangements	Section 4, Page 11
d). Consider the interaction with CMP250	Section 4, Page 16
e) Consider impacts on foot-room, High Frequency Response and fuel equivalency (e.g. battery and conventional generation).	Section 4, Page 26

2 Original Proposal

Section 2 (Original Proposal) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup.

Defect

Under the current Charging Methodology, storage providers pay BSUoS on both their import and export volumes (in addition to the BSUoS costs implicit in their 'fuel cost'). Storage providers are therefore contributing more towards the cost of balancing the system than other users. Storage providers, who compete with generators in the provision of ancillary services, are therefore at a competitive disadvantage, which is likely to distort market outcomes and so disadvantage consumers.

What

CUSC 14.29.4 states that all Parties with the exception of Balancing Mechanism Units (BMUs) and Trading Units associated with Interconnectors are liable for BSUoS charges. This includes energy taken from the grid by storage facilities. All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt, excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period.

Why

Requiring storage operators to make a greater contribution (at least 2-fold) towards the recovery of BSUoS charges than their competitors is inequitable - the requirement to pay BSUoS on both of the import and export volumes should be removed from these facilities. Failure to address this issue will perpetuate a distortion to competition between storage operators and other generators. Moreover, given the nature of storage facilities and the system support role that they play, they are very unlikely to impose such balancing costs on the system when compared to other users.

How

A solution would be to change the BSUoS Charging Methodology within section 14 of the CUSC to remove the liability of BSUoS on storage facilities import volumes.

This will be achieved through defining an Exemptible Storage BMU and removing the liability to pay BSUoS on their imports from the transmission or distribution system. Once defined, the exemption would mirror that already in place for BMUs and Trading Units associated with Interconnectors.

The proposed solution initially did not include storage (CVA or SVA) below 100MW but following the working group discussion, the original was changed by the proposer to include all CVA and SVA storage that meet similar criteria to larger CVA storage.

Detail on why change

Transmission-connected storage operators are liable for the BSUoS on both their import and export volumes to and from the transmission network (in addition to the BSUoS

costs implicit in their 'fuel cost'). Embedded storage pays towards BSUoS but can also receive BSUoS as an embedded benefit (this benefit is being addressed separately through Ofgem's Targeted Charging Review Significant Code Review).

This means that storage operators (particularly storage over 100MW) make a significantly greater contribution towards the recovery of BSUoS charges than their competitors. Failure to address this issue will perpetuate a distortion to competition between storage operators and other generators, and could hinder the development of new storage that could meet the increasing demand for flexibility. Moreover, given the nature of storage facilities and the system support role that they play, they are very unlikely to impose such balancing costs on the system when compared to other users.

3 Proposer's solution

Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 44 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The proposed solution initially did not include storage (CVA or SVA) below 100 MW but following the working group discussion the original was changed by the proposer to include CVA and SVA storage that meet similar criteria to larger CVA storage.

Following detailed discussion over many months, a single proposal has been put forward to meet the defect that exempts certain types of storage form demand BSUoS. In order for a storage facility to be excluded from BSUoS demand charges, it would need to meet the following criteria:

- It must be operated by a person who holds a generation licence
- Its only function must be that of electricity storage (based on the draft Ofgem licence condition)
- It is registered as part of a CVA BMU, which is explicitly recognised in either a Bilateral Connection Agreement (BCA) or a Bilateral Embedded Generation agreement (BEGA) with National Grid

  or

- Its Imports and Exports are measured by SVA registered Metering Systems, which do not measure Imports or Exports for anything other than Electricity Storage; and the operator provides a declaration (using the template set out in BSC modification P383) to the SVAA, via its Supplier(s), which SVAA must validate. The declaration will provide important information about the facility, including how it meets the CUSC criteria, its location and related SVA MSIDs

.

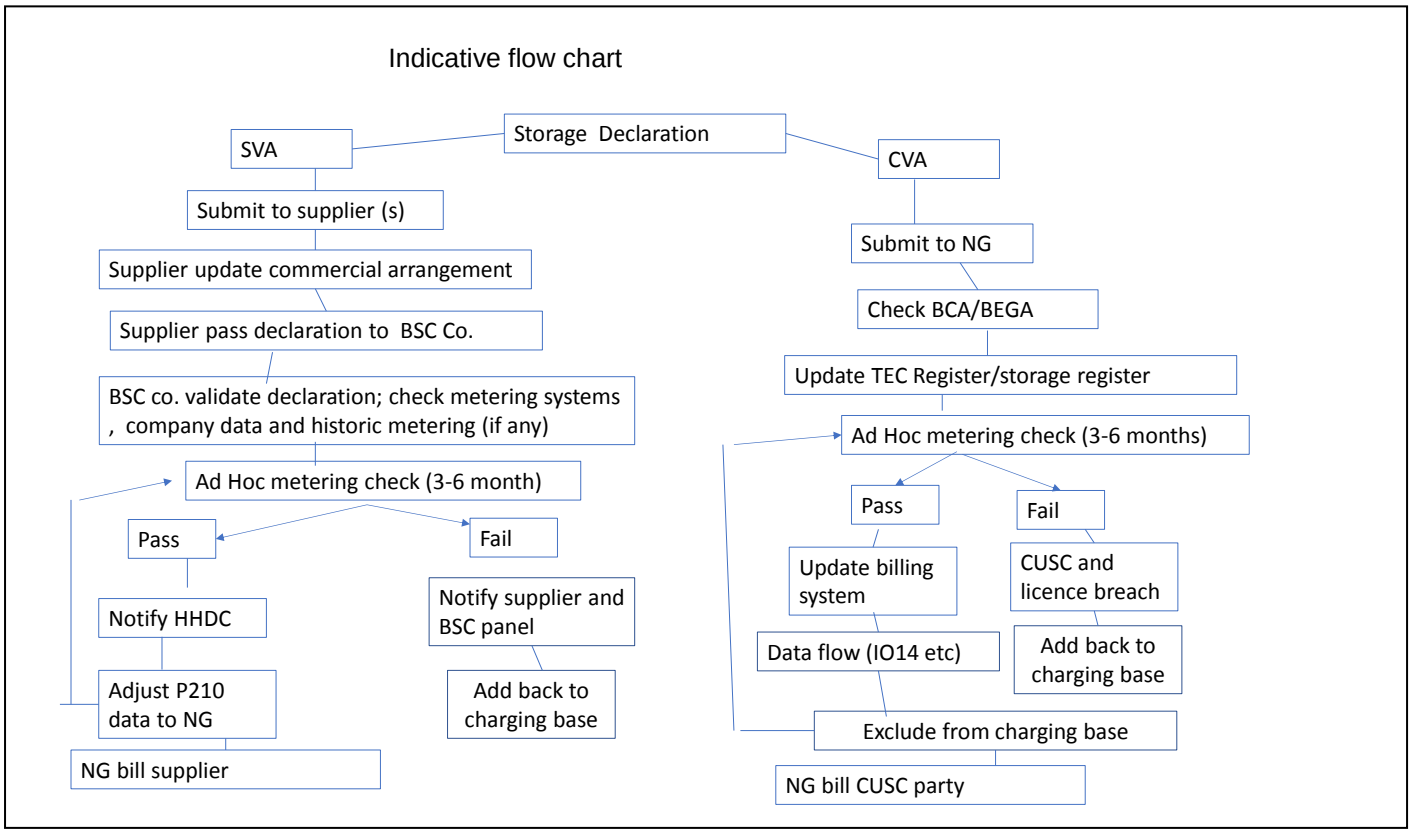
The chart below shows the current base line position for BSUoS and highlights the proposed change.

		T Final Demand	T Generation	T Storage†	D Larger EG**	D Larger Storage**†	D Smaller EG*	D Smaller Storage*†	D Demand
Balancing	Generation		✔	✔	✔	✔	Paid	Paid	
	Demand	✔	✔	✔	✔	✔	✔	✔	✔

CMP281 removes liability ✡

✔ - Pay the charge Paid – can get paid the inverse of the charge when generating
* <100MW EG **>100MW EG
† - may be affected by ongoing storage modifications CMP280 & CMP281
†† - will be replaced by dedicated embedded export tariff following CMP264/5 WACM4 implementation
# - only those connected at HEV level pay distribution demand residuals. All other are exempted

The flow chart below details the proposed methodology for establishing a valid Storage Facility for SVA and CVA connected storage facilities. Details of the SVA validation methodology are set out in further details in BSC modification P383 also set out below of the key definition and declaration that will be required as part of the solution.



Further information can be found within the workgroup discussions section of this report.

Details of any potential cross-code, consumer or environmental impacts and attach or reference any other, related work.

With the inclusion of SVA in the solution, a cross code issue has been dealt with by the proposer raised P383 to facilitate data flows and validation for SVA storage facilities. Although not dependent of the CUSC solution similar changes for storage are being progressed through the DCUSA.

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

No. There was no Significant Code Review (SCR) underway which impacts BSUoS at the time the modification was raised. Both the SCR on residual charges and embedded benefits and the SCR on forward-looking charges and access were initiated after this modification was raised. In addition, Ofgem has said that it thinks that the relative disadvantage for storage from the current arrangements – whereby storage pays BSUoS as both demand and generation – is sufficiently material that it should be

addressed ahead of any potential future change to BSUoS. Please see section 6 for further details.

Consumer Impacts

Removal of this distortion should result in fairer allocation of the costs of balancing the system and hence in stronger competition, which should in turn allow discovery of more efficient outcomes.

4 Workgroup Discussions

1. Introduction

The Workgroup convened 18 times to discuss the issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the CUSC Applicable Objectives

The Proposer presented the defect that they had identified in the CMP281 proposal and highlighted: (1) the fact that storage providers are contributing more towards the cost of balancing the system than other users; (2) the requirement to pay BSUoS on both of the import and export volumes should be removed from these facilities; and (3) failure to address this issue will perpetuate a distortion to competition between storage operators and other providers of ancillary services.

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

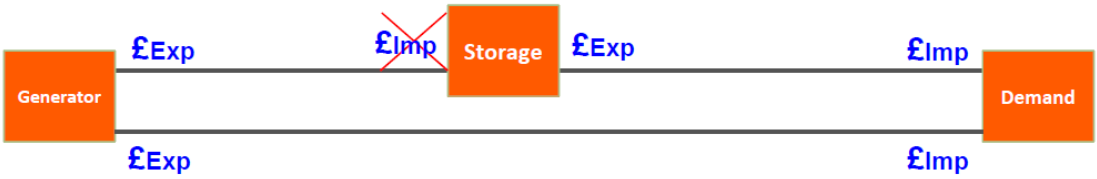
2. The economic rationale for the proposal as presented by the original proposer and the subsequent adopter of the proposal

Under the original proposal, electricity storage facilities import electricity from the Total System in order to be able to store it. The stored energy is exported back to the system in the form of electricity for consumption by an end consumer. The storage facility does not have self-consumption as its primary function.

The current BSUoS charging regime can result in “double counting” of energy to the end consumer:

1. The energy is considered to be end-consumption when imported by the storage facility
2. The energy is considered end-consumption when exported back to the National Grid System and measured as consumption by the end-user.

This adds to the operational cost of the storage facility which makes storage facilities less competitive than other providers of flexibility services to the Electricity System Operator (ESO). This adverse effect on competition may result in additional costs being passed through to the end consumer. As well as removing the double counting, the analysis in Appendix 5 shows a net benefit to the consumer of £15m per annum if this change is introduced



The current charging regime means that storage facilities pay BSUoS on both their import and export volumes (in addition to the BSUoS costs implicit in the 'fuel cost'). Effectively CVA storage is paying three lots of BSUoS charges. Storage is therefore contributing more than other users with whom it competes. Removal of this distortion will place generator and storage users who compete with each other in the provision of ancillary services and in the energy market, on a more level playing-field, better facilitating competition which will ultimately be to the benefit of the consumer via reduced pass through costs.

The current charging of BSUoS penalises storage when it acts in a beneficial way for the system. For example, occasions when there is high wind overnight leads to the ESO having to take actions to constrain off wind. These higher constraint costs cause BSUoS costs to be high. When pumped storage units imports energy overnight (providing helpful demand on the system at times when there is low demand and excess generation) it is liable for these high BSUoS costs.

This is not appropriate and means that the costs incurred by non-beneficial behaviour are not picked up by those who cause these costs to be incurred. Instead they are allocated to those who have no impact or are acting in a beneficial way for the system.

Removal of BSUoS charges from energy imported by storage facilities from the National Grid System would go some way to addressing the issues above and in facilitating competition in the provision of flexibility services between storage facilities and other flexibility providers such as generation.

BSUoS as a cost recovery.

Academic literature (e.g Diamond Mirrlees et al)[1] on production efficiency recognised that the most efficient way to collect fixed revenue (e.g BSUoS) is to apply it only to end consumption.

An example of this is rail and postal services that are not subject to VAT. A simple assumption for VAT collection could be that it will be possible to raise more VAT if it is applied to postage and rail costs. This assumption is wrong as it is optimal to have no distortions in production of goods based on recovering fixed (tax like) costs. Businesses that use postage will simply apply the additional VAT plus their processing expenses (inefficiency cost) and apply this cost to the cost of goods and services which are passed on to the end consumer. In addition, competition between business will be improved if

[1] http://darp.lse.ac.uk/PapersDB/Diamond-Mirrlees_2_(AER_71).pdf

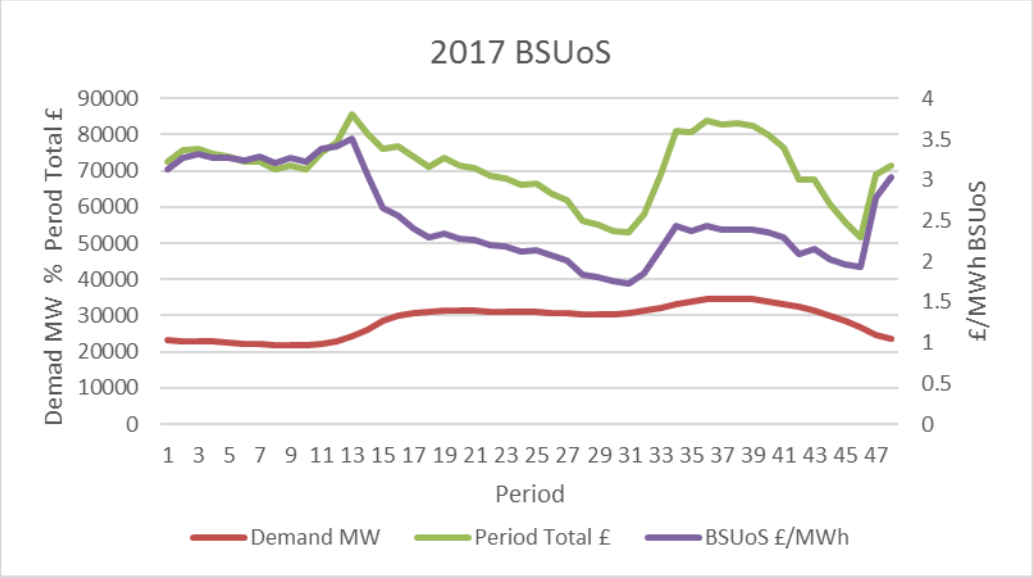
they can compete on the basis of their business designs and production costs that do not include tax-like charges.

A more efficient outcome is to recover the same (higher) amount of VAT directly from consumers. This will result in a lower overall cost, as the additional inefficiency cost does not need to be collected and competition between business will result in a more efficient outcome, based on their business designs rather than the application of a tax-like charge. The application of BSUoS should not therefore distort production decisions and leads to the ultimate conclusion that BSUoS should be applied only to end consumption.

Although BSUoS is a half-hourly charge, most of the individual elements relate to actions that are required across multiple time periods with the magnitude determined principally by the demand shape. At all points in the day generation and demand must match so actions in one time period cannot be divorced for those in other time periods. In reality, although the cost (£m) may be flat across the day, this will drive a high BSUoS price at low demand period. The shape of BSUoS (£/MWh) is simple a cost recovery across a varying number of consumers, exacerbating the current distortion.

BSUoS across the day

The chart below shows for 2017 the average period daily cost of BSUoS, average period demand as well as the demand. £/MWh charge. As can be seen, the period cost (allocated) over night and over the system peak are similar with similar amounts being spent overnight and during peak daytime, but the resulting £/MWh change is far from flat. Driven principally by demand and the need to ensure sufficient head- and foot-room during lower demand periods, the overnight rate is roughly 1.5 times the daytime rate. This is driven by the methodology which recovers a similar period £k amount over lower demand periods.



As highlighted in appendix 5, the allocation methodology leads to higher daytime wholesale prices as storage is subject higher levels of BSUoS on its imports.

The ESO-led BSUoS task force issued its final report on 31 May and concluded that BSUoS should be treated as cost recovery, the summary conclusion is set out below.

> "Deliverable 1 - does BSUoS currently provide a useful forward-looking signal?
>
> When assessing the current BSUoS charge, the Task Force found that it does not currently provide any useful forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market. The Task Force identified five main reasons why this is the case: the current BSUoS charges are hard to forecast, complex, increasingly volatile, that other market signals are more material and so take precedence, and the current BSUoS charge applies to all chargeable users of the transmission system on an equal basis."

This conclusion supported the proposers view that BSUoS is cost recovery and should only be applied to final consumption.

3. The materiality and concern that it would lead to increased costs for other demand users

The reduced recovery of BSUoS charges from storage operators, as a result of implementing CMP281, would need to be recovered from the balance of parties liable to BSUoS.

Based on the 2016/17 charging year, imports from pumped hydro amounted to approximately 4TWh which represents 0.78% of the total volume (520TWh) liable for BSUoS charges. Under the original proposal, the reduction in recovery of BSUoS from the pumping volume would be recovered across the remaining volume resulting in an increase in BSUoS charge of £0.02/MWh (increase from £2.44/MWh to £2.46/MWh).

The value of Residual Cashflow Reallocation Cashflow (RCRC) over the same period was approximately £0.06/MWh. Excluding storage import volumes from the RCRC calculation would have resulted in an increase of £0.00051/MWh to other parties which in the Proposer's view would not appear to be a material adjustment.

In 2016/17, RCRC cash-flows attributable to pumped storage imports constituted around 1.4% of the total RCRC cash-flows. The Proposer considers that this amount is insufficiently material to justify a change to the RCRC calculation within the BSC and it has no impact on cross border trade. However, should other Parties believe otherwise, the appropriate change may be raised under the BSC modification process.

4. The current regulatory and licencing regime

The Workgroup discussed the proposed modification in the context of the current legislative framework for generation activities and the generation licence changes to accommodate storage facilities proposed by Ofgem and BEIS[2].

The Workgroup noted that the provisions of the Electricity Act above allow a person with an Electricity Generation Licence to supply electricity to facilities, including storage facilities, under the terms of this licence, provided such facilities are associated with the generation activities authorised by the licence under the Act. This supply of electricity under a Generation Licence is the current practice at all large power stations, including pumped storage, operated by Generation Licensees.

The Workgroup noted that it would be the responsibility of the relevant party to ensure compliance with its generation licence and the Electricity Act in relation to supply of electricity under a generation licence. In this context if was felt that no additional performance assurance or auditing process was required under the CUSC arrangements (i.e. the CUSC would rely on self-compliance with the legislative framework, noting that breach of licence and/or breach of the Act could have serious consequences).

Public Service Obligation

One Workgroup member noted that in considering CMP281 and the differential treatment of storage in relation to BSUoS they had reviewed the "Government Response to the technical consultation on the model for improving grid access" published in July 2010 (copy attached). This document made it clear that "constraint" costs should be socialised across all generators and suppliers on a per MWh basis as a public service obligation on an enduring basis. The following may be relevant:

> "*We consider that the key features of the Government's intervention amount to a Public Service Obligation (PSO) on transmission licence holders (National Grid and the two Scottish transmission owners) for the purposes of the EU Internal Market in Energy Directive. This is an obligation placed on electricity undertakings by Member States in the public interest, for reasons that can relate to environmental and climate protection or security of supply. As required by the Directive, a PSO must be notified to the European Commission, which we intend to do following implementation. The effect of implementing as a PSO is to create a stable access regime, enshrined in the licence*" (Page 3 of Attachment 1)

> "*The socialisation of constraint costs is to be fixed into the transmission licence and the Government considers that this constitutes a Public Service Obligation (PSO). A PSO is required to be clearly defined, transparent and verifiable. For these conditions to be met, it must be clear how the costs elements are to be treated, operating in a manner that is capable of being verified. Even if it were reasonably practicable to isolate the direct causes of Connect and Manage from other causes of constraint costs (which as we have said we do not consider is the case), this would lead to greater complexity and be more likely to lead to*

[2] "Clarifying the regulatory framework for electricity storage: licensing, Ofgem, 29th September 2017

disputes as to the cause of costs, which would increase uncertainty in the charging mechanism". (Page 12 of Attachment 1)

"*We expect the PSO to be in place as long as it is needed to support our climate change, renewable energy and security of supply targets. We will of course need to ensure that our policy continues to operate in a manner compatible with EU law*." (Page 26 of Attachment 1)

"*It is necessary to fix the socialisation of constraint costs in order to give investors certainty as to the model for grid access – it is a key feature of the successful achievement of the policy. As a 'general principle', the socialisation of costs will fall to be applied by the regulator when fixing or approving a specific charging methodology. We are not fixing or approving any specific methodology*". (Page 26 of Attachment 1)

Socialisation of Costs

"All constraint costs, including those arising from advanced connection, will be socialised across all generators and suppliers on a per-MWh basis, as they are at present under the Interim Connect and Manage arrangements. Standard condition C26 of the transmission licence sets the principle of socialising constraint costs on an enduring basis". (Page 33 of Attachment 1)

This is reflected in C26 of the ESO licence as follows:

"6. *The licensee shall use all reasonable endeavours to ensure that in its application of the use of system charging methodology in accordance with standard condition C5 (Use of system charging methodology), use of system charges resulting from transmission constraints costs are treated by*

the licensee such that the effect of their recovery is shared on an equal per MWh basis by all parties liable for use of system charges."

CMP281 will need to be reviewed in the context of the direction from the Government, the intent to socialise costs across generation and demand on a per MWh basis, the C26 licence condition and the PSO notified to the European Commission.

The Workgroups view was supported by the fact that this was not a reason to reject CMP201[3] and that the Government or BEIS would be responsible for giving the appropriate notifications.

[3] CMP201: https://www.nationalgrid.com/uk/electricity/codes/connection-use-system-code/modifications/cmp201-removal-bsuos-charges

5. Interactions with other regulatory initiatives

Interaction of CMP281 and Ofgem's SCR/TCR and wider issues to consider

The July 2017 statement from the Government and Ofgem is set out on pages 11 and 12 of the Government and Ofgem Smart Systems and Flexibility Plan [4]. The relevant text says:

> *It is important that network charges do not prevent a level playing field between different providers of flexibility. It is clear from responses to the CFE and from our engagement with stakeholders that the current network charging arrangements can create a relative disadvantage for storage when competing to provide services.*
>
> *Ofgem's Targeted Charging Review (TCR) consultation re-asserted its view that while storage should pay forward-looking network charges for both import and export, there are instances where storage may currently pay more towards the residual cost of the network than other network users. The consultation sets out a number of proposals to address this. The proposals include removing demand residual charges at transmission and distribution level and reducing BSUoS charges for storage. The proposed changes would apply to standalone storage and storage co-located with generation.*
>
> *Ofgem believes that the relative disadvantage for storage under the current network charging arrangements is sufficiently material that it should be addressed ahead of any wider changes that may take place as result of the TCR. Ofgem therefore proposes storage charges should be taken forward directly by industry through the code governance process, rather than forming part of a wider significant code review. Ofgem is currently reviewing responses to the TCR, which closed on 5 May, and will publish a response in the summer*

Following this, Ofgem's Targeted Charging Review – Significant Code review launch statement dated 4 August 2017[5], it states that:

"The scope of the SCR excludes:

Charging arrangements for storage. Our current thinking is that industry is best placed to bring forward modification proposals to make changes within the current charging framework. We note that at the time of this letter, two code modifications have been raised to address BSUoS and TNUoS charging for storage [CMP281 and CMP280]. We reserve the option, if necessary, of bringing storage charges back into the SCR, and issuing a direction to one or more industry parties to raise modifications."

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[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/631656/smart-energy-systems-summaries-responses.pdf

[5] https://www.ofgem.gov.uk/system/files/docs/2017/08/tcr_scr_launch_letter.pdf

In their November 2017 update [Targeted Charging Review: update on approach to reviewing residual charging arrangements] Ofgem stated that "there are strong arguments to support recovering residual charges from demand, rather than from generators or a combination of demand and generators." Further, Ofgem stated [1.12]" In addition, we have set out our views about potential concerns with storage charges and encouraged industry to take these issues forward. We have also indicated that it may be appropriate to consider reforming BSUoS charges in line with transmission and distribution residual charges, If more fundamental reform of BSUoS is not undertake, for example, through our electricity network access project."

In their 23 July 2018 consultation *Getting more out of our electricity networks by reforming access and forward looking charging arrangements*, Ofgem stated:

[2.27] "Although users can anticipate future BSUoS charges and take action to minimise their exposure to these charges, the costs recovered through BSUoS are not targeted on those users in a forward-looking cost-reflective manner, and instead 'socialised' across all relevant users."

And

[2.31] "We consider that there may be scope to improve forward-looking locational signals sent through BSUoS and TNUoS arrangements **but do not see it as sufficiently high priority to include in an immediate review**.

Since these publications, Ofgem has shared more material giving industry more insight into their direction of thinking regarding BSUoS:

- **BSUoS Summary Note (January 2018):**
  http://www.chargingfutures.com/media/1112/charging-futures_bsuos_summary_jan18.pdf

  This paper details that Ofgem's Electricity Network Access (ENA) project may or may not lead to changes that will affect some of the revenues recovered by BSUoS. This would be through work looking at the residual element of charges and whether elements of BSUoS will change or not. Ofgem also offer a table of 4 options which detail the possible outcomes of this work:

  The possible outcomes for future BSUoS are set out below.

Decision on BSUoS	Electricity Network Access project	Targeted Charging Review
Option 1: Change recovery of constraint management cost charges	May re-design or replace BSUoS charges that recover the costs relating to constraint management	May align *remaining* BSUoS charges with our approach to network residual charges
Option 2: Keep one set of BSUoS charges	May conclude no change to the element of BSUoS that recovers constraint management costs	May align *all* current BSUoS charges with our approach to network residual charges

  This information needs to be considered as part of the solution.

- **Storage charging Summary note (February 2018):** http://www.chargingfutures.com/media/1126/cf_-storage-charging-summary-note-feb-2018.pdf

  Ofgem states in this documents that "…It is Ofgem's view that storage should continue to pay forward-looking network charges for both import and export (noting that forward-looking network charges are currently under review in the Electricity Network Access project)."

  Therefore, if elements of BSUoS change and there are clear residual and forward looking elements, it will need to be considered as part of the solution to ensure it is future-proof.

- **Ofgem's Access &Forward-Looking Charges consultation document (July 2018):** https://www.ofgem.gov.uk/system/files/docs/2018/07/network_access_consultation_july_2018_-_final.pdf

  Within this document, Ofgem give further insight into their views on BSUoS:

  - BSUoS currently is more of a cost recovery charge, rather than a forward-looking charge, and does not contain a locational element.
  - Cost are recovered through BSUoS in a socialised and homogenous manner at present. BSUoS charges can be anticipated and exposure to them minimised, however charges are not targeted on these users in a forward-looking cost reflective way.
  - Ofgem are considering BSUoS as part of the TCR:SCR and they are also considering it as part of CMP250. The decision on BSC modification P344 reduces the justification for different approaches to BSUoS charging.
  - Ofgem recognise that the Connect and Manage scheme is leading to higher constraint costs for the ESO (the Western Link should help to reduce these costs once operational). Therefore, there is value in recovering costs in a more cost reflective manner. They are aware that Government would need to approve any changes to this.
  - Ofgem also note that there is scope to improve forward looking and locational signals sent through BSUoS but they do not feel that this is a high priority area that needs immediate review. However, Ofgem do see value in further work on BSUoS more generally, to consider if it can provide forward-looking signals for the different elements it recovers and whether it can be made more cost reflective.
  - Ofgem also note that BSUoS embedded benefits are under review as part of the TCR. If BSUoS remains a cost recovery charge then they will consider whether to reform BSUoS in line with reforms to TNUoS and DUoS residual charges as part of the TCR.

  These points were considered by the Workgroup when creating a solution for CMP281.

6. Implementation - requirement to hold a generation licence and compliance with storage definition

Ofgem has consulted on changes to the standard conditions of the generation licence that would clarify how the licensing regime applies to the operators of certain types of storage facility. These changes are intended to make clear that: Electricity Storage is considered a form of generation; that storage operators seeking relief from Final Consumption Levies must hold a generation licence; and that to hold a generation licence the licensee operating an Electricity Storage Facility must not have self-consumption as its primary function. These changes make clear that generation includes various types of storage facility and goes on to set out the various technical parameters that are allow different types of storage to be classed as generation:

Ofgem's draft definition (key criteria) is:

> *An "electricity storage facility" means a facility where Electricity Storage occurs[6]. Electricity storage is the conversion of electrical energy into a form of energy, which can be stored, the storing of that energy, and the subsequent reconversion of that energy back into electrical energy. An electricity storage facility shall not have self-consumption as the primary function when operating.*

The group preferred to adopt a definition of storage that has been consulted on, that reflects a definition suggested by a trade association representing storage, and is expected to come into force. Therefore, the CUSC position seeks to achieve consistency with the expected licence arrangements.

The Workgroup considered there were three key reasons for this:

i. The Electricity Act envisages certain core activities, including the generation of electricity, which only a licensee (or a person subject to an exemption) may perform. Therefore, in order for the Imports to a storage facility to be distinct from an ordinary Supply, the Workgroup considered that being operated by a generation licensee provided that assurance.

ii. An advantage of ensuring operators have a generation licence is related to validation and verification. That is, to obtain a generation licence parties will need to apply to the Authority for a licence. This process will provide comfort that the generation licence holder meets the criteria for a generation licence and the act of holding a licence is a public act which can be verified. It will provide assurance to CUSC Parties about the identity and activities of the licence holder. In particular, the Workgroup considered that, given the modification would also

[6] Definition from draft generation licence condition for storage at https://www.ofgem.gov.uk/system/files/docs/2017/10/elecgen_slcs_consolidated_29sept2017.pdf

apply to SVA storage, requiring operators to hold a licence is a necessary precaution.

iii. Relief from Final Consumption Levies (FCLs) is predicated on the generator holding a generation licence – which means that the facility is excluded from the ordinary meaning of Supply that is used to determine volumes that are subject to FCLs. Requiring storage facility operators to hold a generation licence to be relieved from BSUOS Demand Charges would ensure consistency with the approach to FCLs and provide regulatory certainty to storage operators as to what they must do in order to be relieved of certain charges.

The Workgroup also considered arguments that requiring operators to hold a generation licence would places an extra burden on operators and so discriminate against those who do not hold a licence.

The Workgroup considered the argument that the requirement to be operated by a generation licensee is not envisaged by Ofgem when setting out its expectations for reforms to network charges for storage. In addition, it was noted that the policy rationale for FCLs and for network charges are distinct and different. The workgroup also recognised that the proposed requirement could place an administrative and regulatory burden on operators to acquire and retain a generation licence.

However, the Workgroup noted that the likelihood is that the storage operators seeking relief from networks charges are likely to also seek relief from FCLs. Because relief from FCLs requires that the operator holds a generation licence, the Workgroup considered that requiring storage operators to hold a licence for BSUOS purposes would not be a considerable burden, as the operator would already hold a licence to satisfy the FCL requirement.

On balance, the Workgroup considered that the arguments for requiring operators to hold a licence outweighed those against.

The Workgroup also noted that for this modification a generation licence is required but that at some point it may be appropriate to review (potentially relax) this requirement once experience of the processes had been gained.

Compliance with storage definition

For CVA Storage, non-compliance with the CUSC storage definition would be a breach of the CUSC and subject to CUSC remedies.

For SVA storage to provide assurance that Storage Facilities who apply for exemption via their supplier meet the CUSC criteria, sufficient information needs to be provide to the Supplier, (and subsequently to BSCCo in accordance with P383) such that the Supplier and BSCCo can validate (and continue to monitor) any application against the CUSC criteria. This will also provide assurance to other market participants that an operator is not taking advantage of the arrangements and receiving relief from BSUOS charges.

For all SVA Storage Facilities new CUSC and BSC processes will be introduced to ensure that sufficient information is provided in a director-signed declaration that

confirms that a facility meets the CUSC criteria. The BSC processes will include up-front validation and ongoing monitoring to provide assurance to CUSC Parties.

Impacts on co-locational generation/storage assets

Significant time was spent by the working group considering the effect of co-location of end use demand with storage and how to ensure that the users could not operate end consumption behind storage. There were concerns raised by working group member that without a “strong” definition of storage, storage facilities located adjacent to demand or embedded generation and behind the settlement meter for that demand/generation (BTM) may also gain exemptions. The working group believe that with monitoring and using the Ofgem definition of storage in the CUSC, this situation will not occur.

7. BSUoS treatment of BCA and BEGA storage (larger CVA-licenced) compared with SVA smaller CVA storage

The working group considered if the proposal should be extended to SVA storage and suggested SVA storage should be relieved from paying demand BSUoS which would then level the playing field on the demand BSUoS side compared to CVA storage.

One member considered that if CVA was treated differently to SVA for demand BSUoS under CMP281 this may and make it harder to implement without discrimination. In fact, in introduces a further discrimination as SVA would then be more advantageous than CVA - it would not pay BSUoS on its imports and would receive BSUoS as an embedded benefit when generating. The Workgroup explored this view further.

Under the current base, BCA and BEGA storage (larger CVA-licenced) are charged for BSUoS on both imports and exports. In 2017 a typical storage installation of this type will have paid £3.41/MWh for demand BSUoS and £2.33/MWh for generation BSUoS. The combined contribution was £5.74/MWh. Removing the liability for demand BSUoS for these types of storage facilities will reduce this class of generation’s BSUoS liability by on average £3.41/MWh

SVA and smaller CVA storage pay demand BSUoS usually via their supplier but typically receive a credit from their supplier for generation BSUoS. If the assumed credit is 90% of the generation BSUoS, SVA and smaller CVA storage currently pays a net contribution of £1.3/MWh. Removing the liability for demand BSUoS for this type storage facility will reduce this class of generation BSUoS liability by on average £1.30/MWh

The removal of demand BSUoS from smaller CVA and SVA generation will place all storage demand on the same basis for BSUoS import costs. Since SVA and small CVA generation will still retain the generation embedded benefit that stands at around £ 2.33/MWh, this class of storage will still be in a better position compared to CVA storage.

The review of embedded benefits may lead to the removal of the current generation BSUoS credit for SVA and smaller CVA storage generation and potentially apply a

charge for generation BSUoS. The review coupled with this modification would place all licenced storage on a level playing field with respect to BSUoS charges.

A working group member noted that there were two DCUSA change proposals looking to remove residual charges from storage/embedded generation – DCP319 and DCP321. These were broadly the DCUSA's version of CMP280 and CMP281. The Workgroup noted that the DCUSA proposals have both had proposer support withdrawn, this coming swiftly after a direction from Ofgem that CMP280, DCP319 and DCP321 should apply to storage only and not all generation. The reason for the withdrawal of support is that the proposer felt that removing residual charging for storage only (not generation more broadly) would create a distortion between storage and all other embedded generation. No Workgroup members for DCP319/321 chose to support these proposals or raise alternatives following Ofgem's letter and the proposer's withdrawal of support. This is a view expressed in the consultation response. New DCUSA modifications have subsequently been raised to address storage.

Given these various issues the proposer decided to include SVA generation in the scope of the modification

8. The proposed procedure for the inclusion of licenced embedded storage.

Expanding the modification from larger CVA storage to include embedded storage (larger CVA and SVA) is not without complexity. The methodology that is proposed to be adopted is described is detailed below for a new storage provider is as follows:

An "SVA Storage Facility" is a Storage Facility that:

i. performs Electricity Storage as its sole function;

ii. is operated by a Storage Facility Operator who also holds a generation licence;

iii. has its imports and exports, measured only by Half Hourly Metering Systems which are registered in the Supplier Meter Registration Service (SMRS) as part of a Supplier BM Unit, and where those Half Hourly Metering Systems only measure activities necessary for performing Electricity Storage;

This information is passed then the supplier and then from the supplier to the BSCCo for verification validation and audit.

Once the metering system has been approved under the BSC, the BSC systems will request that metered data associated with the storage facility is reported to it, which it will aggregate and report this to National Grid. National Grid may then exclude the aggregated storage volumes from the relevant Suppliers chargeable BMU. The interface and data flows between BSC and National Grid will be detailed in the BSC.

The CUSC contains provision that modify the definition of chargeable demand to be the current definition exclude demand from storage meeting systems that are approved under the BSC.

A separate BSC modification has been raised to put in place this methodology, P383.

9. The potential expansion of BSUoS exemption to all generation demand.

A working group member initially proposed that not only storage demand, but all licenced generation demand should be excluded from the a BSUoS charge. The group considered this and whilst it could arguably lead to a more efficient and economic outcome economic and could be implemented relatively easily it was not the prime purpose of the proposal and would lead to different treatment between licenced and unlicensed generation. If the proposal was scaled to SVA this was likely to cause significantly more issues as in general SVA generation operate without a licence. It was also clear that a storage only option was potentially clearer to implement given the potential for generation to co-locate with demand which would necessitate the creation a further definition. On balance, it was decided to only progress a proposal that covered licenced generation that can meet the storage definition and has a BCA or BEGA

Ofgem in its TCR may well consider this issue further but the group did receive a note from the Authority encouraging the group to look at only storage options.

10. System changes

To implement this modification there would need to be changes within the Charging and Billing system (CAB) to accommodate it. There would need to be a mechanism which would flag to the system those BMUs are impacted by the modification. The core calculations of the charging system will need to be modified to treat such BMUs differently, which will then lead to changes in reporting and billing, so that these changes are implemented across the board. Costs are currently estimated to be between £500k and £1m but depends on the division of systems work between NG and BSC. This process would also need to be detailed within the legal text for this modification so that identification of BMUs is robust and consistent.

If Elexon are responsible for maintaining the records of affected units and subsequently flagging to National Grid through existing BSUoS flows, changes to the file importing mechanism would also be required.

11. Transitional Arrangements

The implementation of CMP281 is not expected to have a material impact on other parties and as such, it is proposed that there would be no requirement for any transitional arrangements.

The Proposal, if approved, should be implemented to coincide with the start of a Charging Year (i.e. 1 April) and should be implemented in the first practical Charging Year following a decision by the Authority. If an Authority decision is available in time,

the change could be implemented no earlier than 1 April 2021. The Workgroup noted that there may be an impact on Suppliers from an early implementation date however considered that the April 2021 is being offered as the earliest practical date. One Workgroup member suggested 1 April 2022. The Workgroup agreed that the implementation date is a decision for the Authority.

Given the nature of BSUoS although a 1st April change is desirable given the magnitude it would be possible but not preferable to implement a mid-year change. .

12. Post Workgroup Consultation Discussions

Post Workgroup consultation, the Workgroup convened on multiple further occasions. During this period, the Workgroup continued to develop the modification, taking into account responses to the consultation, full responses can be found in both Section 5 and Annex 3 During this period, there were broader developments within industry which the Workgroup had to take into consideration whilst developing CMP281.

Ownership of Modification

The original proposer of this modification, Scottish Power, relinquished ownership of the modification post-Workgroup Consultation[7]. The modification was adopted by Engie who took the modification forwards. The original proposer remained on the Workgroup in the function of a Workgroup member until April 2019, when he withdrew from the Workgroup due to retirement.

SCR/TCR

On 4 August 2017[8], Ofgem announced that they would be launching a Significant Code Review/Targeted Charging Review, which would have two main objectives, namely to "consider reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in future"; and "keep the other 'embedded benefits' that may be distorting investment or dispatch decisions under review". As CMP281 and its TNUoS equivalent modification, CMP280, were raised before this date, the modifications both continued to develop despite the potential for some overlap in scope of the SCR/TCR.

When the Authority published their consultation on the TCR/SCR, the Workgroup agreed that the picture in terms of scope was much clearer for CMP281, when compared with CMP280, which had both generation and storage within its defect. The National Grid ESO representative opined that the direction of the SCR/TCR after Ofgem's November publication was broadly in the same direction of travel as the modification. As such, the CMP281 solution need not look into an SVA solution.

Ofgem's representative stated that the Workgroup should progress the modification based on storage as per previous Authority direction. Ofgem's representative stated that the Authority do not intend to interfere with the work of the Workgroup but highlighted

[7] Inset Link

[8] https://www.ofgem.gov.uk/system/files/docs/2017/08/tcr_scr_launch_letter.pdf

the principles raised by Ofgem within the SCR/TCR, and that the work that the Workgroup are doing is broadly in line with Ofgem's direction.

Solutions and Potential Alternative Solutions

The Workgroup held discussions around the nature of the solution, and how best to proceed. It was suggested that the best way to carry forward the proposal would be to look at a CVA (Central Volume Allocation), storage only solution, as per original CMP281 proposal. This proposed method of moving forward was considered to be a better option by some Workgroup members, as it would satisfy the issue set out in the original proposal.

Workgroup members discussed the solution at length. A Workgroup observer stated that on the BSUoS side he believed that an Embedded Benefit solution is intertwined with any solution for charging or generation storage demand more generally, so to raise an SVA alternative to CMP281 may be counter-productive. Other Workgroup members agreed initially, but there was also some disagreement in regards to the thought process to not include a solution which also took in to account an option for SVA.

As the Workgroup discussion developed, it became evident through discussions and also interactions with Ofgem that a solution which covered both CVA and SVA solutions would be preferable, and would also potentially give Industry Stakeholders confidence that the solution would be more encompassing of storage, regardless of volume allocation method. As such, post Workgroup consultation, the proposer and the Workgroup undertook work on amending the original solution to also encompass SVA storage.

Scope of Defect/Solution

Several Workgroup members agreed that whilst the CMP281 solution was narrow, this reflected the fact that the definition was also narrow. It was opined by the National Grid ESO representative that a CVA only solution for CMP281 would be beneficial, as accompanying issues would be addressed under the TCR. Another Workgroup member stated that bi-lateral connection agreements only encompass BMU units. However, a proposal could be made to look at SVA solutions separately to CMP281, and that it was important the Workgroup considered this because the CUSC works on bi-laterality. There may be ways of addressing this under the CUSC so that parties may access reliefs and benefits if they are involved in such an interface, however several Workgroup members agreed that the bigger issue is looking at how the CUSC interfaces with parties, and separately how the CUSC interfaces with charges.

National Grid ESO stated the other outcome from a CVA solution was that to access such benefits, a party would need a Bilateral Connection Agreement, or a BEGA. Acceding to the current iteration of the CUSC, this would therefore a pre-requisite. A Workgroup observer questioned how this translated into the distribution market, stating the issue was not to necessarily differentiate between CVA and SVA, but to differentiate between different types of activity. The observer further stated that the principle in his opinion is that the proposed solution is coming from the perspective of which parties are charged, but the nuance is around what activities the parties are charged for.

The proposer reminded the Workgroup that time was of the essence and we would be better served as a Workgroup to concentrate on the storage issues as opposed to looking at overarching issues.

The Workgroup continued by discussing the potential alternative. A member suggested that a potential alternative could include generation by making very small tweaks to the original. NGESO stated that extending the solution to all CVA generation was no more complex than to just storage. it would be just as easy for them to include this to BCA and CVA registered parties. The member continued, stating that regardless of the definition of storage this would need to be included in the license..

The Authority questioned whether the NGESO would ever go to a site and investigate whether a storage site was storage only. The Workgroup replied there was recourse in the CUSC and any party contravening the CUSC could in fact be disconnected. National Grid ESO stated they would not be in a position to go to site and assess whether a site was compliant.

Process flows for amended solution

In later Workgroups, the flows to facilitate the solution encompassing both CVA and SVA sites were discussed and the solution was developed to facilitate this and is included in section 4.

13. Balancing Services Task Force

The Balancing Services Task Force was launched in January 2019, and looked to make the Balancing Services Charges more forward looking and cost reflective. Several of the Workgroup members on CMP281 also hold positions on this Task Force. In their open letter on the implications of charging reforms on electricity storage dated 23 January 2019[9], Ofgem directed that the CMP281 Workgroup should take into account the outputs of the Balancing Services Task Force. This was reiterated by the CUSC Panel during their January 2019 meeting[10]. The Workgroup monitored the outputs of the Balancing Services Taskforce, with particular emphasis on any specific implications on electricity storage moving forwards.

The task force final report was issued on 31 May. It concluded that it was not feasible to charge any of the components of BSUoS in a way that could give a forward-looking signal, and that therefore BSUoS should be charged as a cost-recovery as set out in the conclusion below.

Conclusion

Based on their work the Task Force therefore concluded that: It is not feasible to charge any of the components of BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower

[9] https://www.ofgem.gov.uk/system/files/docs/2019/01/storage_and_charging_reform_2201f.pdf - Ofgem open letter on the implications of charging reform on Electricity Storage

[10] https://www.nationalgrideso.com/document/139911/download - CUSC Panel January Minutes

costs to customers. Therefore, the costs included within BSUoS should all be treated on a cost-recovery basis.

The Task Force believes that cost-recovery charges should aim to minimise market distorting signals, to benefit the system and ultimately consumers. However, the current construction of the charge may inadvertently send signals that are detrimental to the system.

14. CMP308

The Workgroup noted that CMP308 has no interaction with CMP281.

15. Legal text changes – updated

Please seen Annex 3 of this report for the finalised legal text

16. Generation license further consideration

The group considered if the need for a generation licence should be a prerequisite for the final proposal. The group noted the pros and cons of using this as an approach.

Pros

- The generation licence allows for own use consumption but would not allow energy to be supplied to others without an exemption. This requirement will be helpful in ensuring that the storage facility demand is only used to support the generation
- The Smart Systems and Flexibility Plan (SSFP), sets out the view position that only generation licence holders will be excluded from the various levies (P22)

  "***Electricity supplied to generation licence holders is excluded from the supply volumes used to calculate the costs of the Renewables Obligation (RO), Contracts for Difference (CFD), Feed in Tariffs (FITs) and Capacity Market auctions. Holders of either a generation licence or the new storage licence to be consulted on by Ofgem (see 1.2) will, as a result, not be liable for such levies.***"

  The approach of requiring a generation licence is compatible with this approach.

Cons

- Various classes of exemptible storage facility would be excluded from the benefit due to their size unless a generation licence was obtained.
- The cost and process and obligations relating to of obtaining a generation licence may be prohibitive for small storage facilities.

Having discussed these issues, it was felt that the Pros outweighed the cons. **There will therefore be a requirement to hold a generation licence**. If at some future time the generation licencing regime was reviewed it may be possible to reconsider this approach with a further modification but to ensure a timely implementation maintaining a generation licence requirement was the preferred approach

Auxiliary demand at storage facilities further considerations

The working group discussed the issue of how to ensure that the demand used by a storage facility was used by the facility for subsequent generation and was not used for any other purpose. It noted that imports fall into two classes:

1. Imports that are directly used to store energy. This typically would be power to the storage pumps or to power the converter that stores energy in a battery. These could be referred to as the principle storage device.
2. Auxiliary equipment that are needed to support principle storage device such that it can operate in a safe and controlled way. Examples of these would be fire suppression systems, cooling fans, lighting, compressors, auxiliary pumps, control and security systems etc. These are systems that a reasonable and prudent operator would provide to support the principle storage devices operation.

The group noted the different types of use and were comfortable that both types were needed to operate a storage facility and would be covered by the proposed definition of "sole" use.

In reality, given the metering arrangements for most new storage sites (batteries) it would be not possible to separate the two demand uses and the magnitude of the energy consumed for auxiliary equipment is small compared to the principle storage devise. Three of the existing pumped storage stations separately meter station load. The percentage of power used to power auxiliary equipment was presented to the working group and is shown below. It is typically less than 1.5% of total demand.

Station load as a % of imports

	Ffestiniog	Cruchan	Foyers
2015	1.43%	1.26%	1.48%
2016	0.97%	1.49%	1.29%
2017	1.08%	1.20%	1.15%
2018	1.36%	1.73%	1.35%

The group was keen to ensure that where other demand that was used on the same site as the storage facility but not used "solely for storage" would need to be separately metered and not included in the storage facility demand. The group discussed several types of demand that would not be allowed including:

1. On-site demand used by unrelated business or sold via a private wire.
2. Site demand used to support a much larger site than was required for a storage facility. Examples of this could be the site demand used for an industrial complex where a small battery system was located.

To protect against these types of use, the definition contained in the CUSC would need to provide sufficient comfort there these types would be excluded. The link to a generation licence was considered helpful, as well as a monitoring regime that would

establish that metering of the storage facility was such as would reasonably be expected for a storage facility.

5 Workgroup Consultation Responses

The CMP281 Workgroup sought the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

The CMP281 Workgroup Consultation was issued on 22 October 2018 for 15 Working Days, with a close date of 12 November 2018. Two additional questions to the standard Workgroup consultation questions were asked.

Response from	Q1: Do you believe that CMP281 Original proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives?	Q2: Do you support the proposed implementation approach?	Q3: Do you have any other comments?	Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?	Q5. Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?	Q6. Do you believe that the original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?
Binoy Dharsi, EDF Energy	Ofgem state in their TCR consultation (published 13th March 2017 paragraph 1.31) *"We think that the way charges affect storage at present create a relative disadvantage for storage operators, in comparison with generators connected at the same voltage level"…." This is because…transmission-connected storage pays BSUoS as both demand and generation. In order to secure a more level playing-field, we think that*	Yes	No	No	We do not believe there will be any issues (beyond business as usual) in relation to tariff stability. The impact is on a very small percentage of the entire BSUoS cost. We do not foresee any significant impact on operations, billing or processes in the implementation of the Original proposal	Yes. We believe the proposal solution will ensure that competition between generators and storage assets at the same voltage level will be on a fairer basis.

	storage should be liable to pay only….one set of BSUoS charges." Given Ofgem's statement in the above cited extract we believe that the Original Proposal delivers an appropriate solution.					
Libby Glazebrook, Engie	**see following box**	Yes although this is not clearly set out in the consultation. We believe that National Grid as ESO will need to identify the best way to implement the solution. This could be achieved by it "flagging" units that are not charged BSUoS as part of its systems. Alternatively, if the ESO believe that this flagging process is best achieved in the BSC than we would expect National Grid ESO to raise an appropriate modification.	CMP 281 was originally raised to remove the BSUoS charge from transmission connected storage imports and thus ensure that this type of storage only pays one set of balancing charges. This could also be achieved through the revised Original proposal (which applies to all licenced generation – limited to those with a BCA (and BELLA/ BEGA over 100 MW). ENGIE would support either of these changes. Ofgem set out proposals in their	Yes. To address the points made in the response to Q3, the following definition of an "An Exemptible Storage BMU" is proposed. We put forward the following solution to the narrow scope simple solution and have raised this as a consultation alternative: ========== ========== ========== ===== A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):	The modification will result in a lowering of overall cost to consumers based on more efficient market operation. In terms of billing arrangements, it is likely to have minimal effect on both National Grid and other parties to the CUSC.	As noted in the response to Q3, ENGIE would support just limiting CMP281 to CVA storage or widening it to all transmission connected generation demand. Removing BSUoS charges from all but "end consumption" will lead to a more efficient energy system with reduced costs for consumers. It is for Ofgem to decide whether or not the scope of the modification should just be limited to

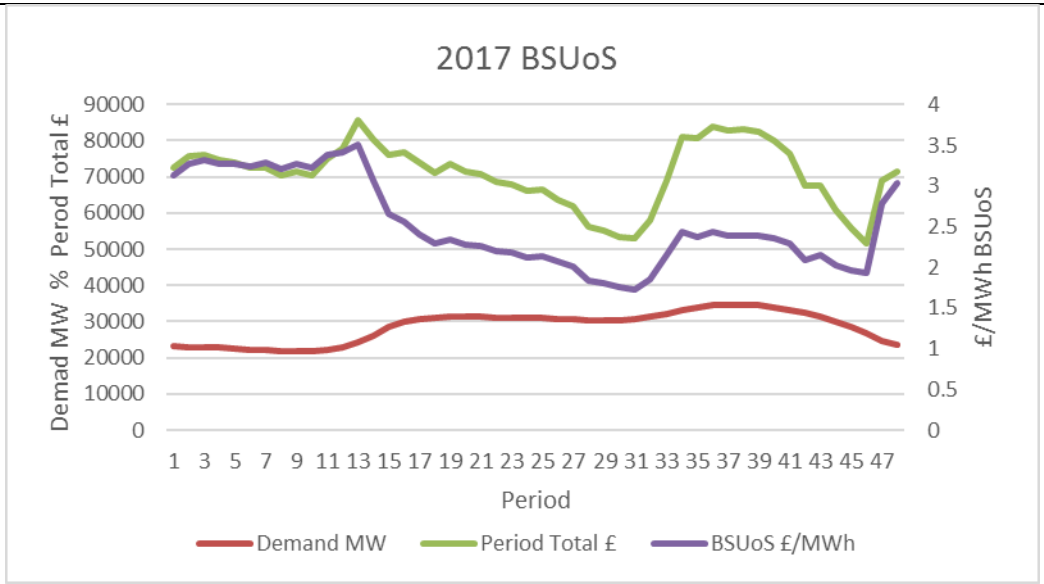
			‘Smart System and Flexibility Plan’ to reduce BSUoS charges for storage and reiterated these concerns in their November 2017 TCR update. To address Ofgem’s specific concern, CMP 281 should have storage only solution as well as the wider solution. We do however note that National Grid estimated costs of between £0.5 and £1m to deliver to storage only solution. No costs have been provided for the wider proposal so it is not possible to compare solutions and have a cost benefit trade off. If the costs of delivering the storage only solution is much higher, then a pragmatic way forward that encompasses Ofgem’s specific concern would be to adopt the new original proposal. Ideally, all storage would be subject to the same BSUoS charges to give the greatest	All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Storage BMUs shall be disregarded. For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology – An Exemptible Storage BMU is a BMU that : is listed in Appendix C of a bilateral connection agreement		storage and for Ofgem to take into account the cost differential of the two options. It is important that both options are put to Ofgem to given them the choice

			consumer benefit. This currently is not the case as embedded storage receives BSUoS when it exports as an embedded benefit and pays BSUoS when it imports (both of these either directly or via the supplier). ENGIE's CUSC modification CMP307 would have addressed the export side of BSUoS as it would have removed the embedded benefit and instead charged embedded storage when exporting. The Authority directed that CMP307 must not be made whilst the TCR SCR is ongoing as the TCR SCR is looking at embedded benefits. The anticipated storage definition within the generation licence could within CMP 281 be used to remove the BSUoS import charge from all licenced storage. However, this would	(BCA) that is associated with an electricity storage facility as set out in the Generation Licence; or is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptible Large power station Agreement (BELLA) above 100MW in size and are associated with an electricity storage facility as set out in the Generation Licence; or the Authority has directed that the BMU is an Exemptible Storage BMU for the purpose of the CUSC Part (a) of definition is designed to only cover transmission-connected storage as only this type of storage has a BCA and will be active once the definition of storage in included in		

			create the situation where embedded storage was not paying BSUoS on its imports and continued to receive BSUoS as an embedded benefit. There would not therefore be a level playing field in BSUoS charging for all storage. Ideally, both these changes therefore need to be in place before BSUoS import charges for embedded storage are removed. There is therefore no reason for CMP281 to address embedded storage for the time being. It is however likely that the storage class within the generation licence will be put in place before the embedded BSUoS benefits issue is resolved. In the response to Q4, ENGIE has suggested an alternative modification that just limits CMP281 to storage with a BCA	the generation licence. We do not believe that any BEGA or BELLA storage facilities exist but have put definition (b) in for completeness. Part (c) allows transmission-connected storage to be identified prior to a licence definition being in place with the authority issuing a notice to National Grid. The Authority would issue a notice identifying for each transmission connected storage BMU (Appendix C part 3 of the BCA).		

			(and BELLA/BEGA over 100 MW) and a storage generation licence or, in the absence of storage generation licence, a notice to National Grid from Ofgem. Ofgem will need to give thought as to whether it is appropriate to create differences in the payment of BSUoS for transmission and distribution connected storage once the licence is in place			
Libby Glazebrook, Engie	Q Do you believe that CMP281 Original proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives?1: **Background** The current methodology of collecting BSUoS from storage demand is leading to increased customer costs. We believe that the proposal to only charge demand BSUoS to end consumption or ENGIE's alternative which does not charge BSUoS on CVA storage imports will deliver customer benefits and improve the efficiency of the current power market in the despatch and scheduling of generation to meet demand. Appendix 1 (attached) details analysis provided by ENGIE to the working group that sets out the issue and the cost savings associated with changes to the current arrangements if applies to CVA storage. CMP 281 was raised in July 2017 and the report demonstrates the issue has been examined by the group and that the group has a good understanding of the range of possible solutions. We believe that it is now time for the group to move forward in a timely fashion with a solution (or solutions) that can be presented to the Authority. **Economic rationale for only charging end consumption**					

	Academic literature (e.g Diamond-Mirrlees et al) on production efficiency recognised that the most efficient way to collect fixed revenue (e.g BSUoS) is to apply it only to end consumption. An example of this is rail and postal services that are not subject to VAT. A simple assumption for VAT collection could be that it will be possible to raise more VAT if it is applied to postage and rail costs. This assumption is incorrect - it is optimal to have no distortions in production of goods based on recovering fixed (tax like) costs. Businesses that use postage will simply apply the additional VAT plus their processing expenses (inefficiency cost) and apply this cost to the cost of goods and services which are passed on to the end consumer. In addition, competition between business will be improved if they can compete on the basis of their business designs and production costs that do not include tax-like charges. A more efficient outcome is to recover the same (higher) amount of VAT directly from consumers. Since the cost of the additional inefficiency does not need to be collected, costs will be lower and competition between business will result in a more efficient outcome, based on their business designs rather than the application of a tax-like charge. The application of BSUoS is similar - it should not distort production decisions and leads to the ultimate conclusion that BSUoS should be applied only to end consumption. Although BSUoS is a half-hourly charge, most of the individual elements relate to actions that are required across multiple time periods with the magnitude determined principally by the demand shape. At all points in the day generation and demand must match so actions in one time period cannot be divorced for those in other time periods. In reality, although the cost (£m) may be flat across the day, this will drive a high BSUoS price at low demand periods. The shape of BSUoS (£/MWh) is simple a cost recovery across a varying number of consumers, exacerbating the current distortion. ***Economic rationale for not applying BSUoS to storage imports*** The chart below shows for 2017 the average period daily cost of BSUoS (green line), average period demand (red line) as well as the demand. £/MWh charge (purple line). As can be seen the period costs allocated overnight and over the system peak are similar but the resulting £/MWh change is far from flat. Driven principally by demand and the need to ensure sufficient head- and foot-room during lower demand periods, the overnight rate is roughly 1.5 times the daytime rate. This is driven by the methodology which recovers a similar period amount over lower demand periods.



This effect leads to higher daytime wholesale prices as storage is subject higher levels of BSUoS on its imports. Appendix 1 details analysis by ENGIE that explores this more with a real world example based on the use of storage on the transmission system.

The current arrangements and three possible solutions

The working group report identifies a number of possible solutions to the issue raised by the proposer and sets out the current position. We have simplified these and put them in table form below broken down into three scenarios based on affected groups:

Current position BSUoS liability	A	B	C

	Transmission Storage	Transmission Generation Demand	Embedded Storage and generation
Demand BSUoS	Pays	Pays	Pays
Generation BSUoS	Pays	Pays	Receives

The efficient positions from a customer's perspective are shown below:

Possible Solution BSUoS liability	A	B	C
	Transmission Storage	Transmission Generation demand	Embedded Storage and generation demand
Demand BSUoS	Exempt	Exempt	Exempt
Generation BSUoS	Pays	Pays	Pays

For each scenario we suggest how the working group should address further work, potentially proposing two solutions to the Authority based on scenarios A and B.

A The narrow scope simple solution

The simple solution exempts transmission-connected storage and embedded storage over 100MW from liability for demand BSUoS and hence improves the cost reflectivity of the system. The group has struggled to arrive at a definition of this type of storage as a storage class within the generation licence is not in place yet. This is why the group moved to the wider solution that applies to all transmission connected generation.

There are currently four transmission connected pumped storage facilities and one transmission connected battery storage facility. Whilst it should be easy to identify these, in practice, in the absence a storage class within the generation licence it has proved difficult for the group to come to a solution and, as such, a definition has not been developed.

We put forward the following solution to the narrow scope simple solution and have raised this as a consultation alternative:

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A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):

All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Storage BMUs shall be disregarded.

For purpose of Section 14(2) of the CUSC – The Statement of the Balancing

Services Use of System Charging Methodology –

An Exemptible Storage BMU is a BMU that :

is listed in Appendix C of a bilateral connection agreement (BCA) that is associated with an electricity storage facility as set out in the Generation Licence;

or

	is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptable Large power station Agreement (BELLA) above 100MW in size and are associated with an electricity storage facility as set out in the Generation Licence; or the Authority has directed that the BMU is an Exemptible Storage BMU for the purposes of the CUSC. Part (a) of definition is designed to only cover transmission-connected storage as only this type of storage has a BCA and will be active once the definition of storage in included in the generation licence. We do not believe that any BEGA or BELLA storage facilities exist but have put the definition (b) in for completeness. Again, this is only active once a storage licence is in place. Part (c) allows an Exemptible Storage BMU to be identified prior to a licence definition being in place with the Authority issuing a notice to National Grid. The Authority would issue a notice identifying for the storage facility, all the BMU's listed in Appendix C of the storage facility bilateral connection agreement (BCA). The BCA details the BMU's that are included in the power station/trading site. Part C flow chart is contained in Appendix 2 An example of a BCA for a storage facility is shown below. NATIONAL GRID COMPANY plc and FIRST HYDRO COMPANY _____ AGREEMENT TO VARY THE BILATERAL CONNECTION AGREEMENT FOR FFESTINIOG _____

Appendix C

Connection Entry Capacity and Transmission Entry Capacity

Company: First Hydro Company

Connection Site: Ffestiniog

Part 1 Connection Entry Capacity

Connection Entry Capacity Expressed as an instantaneous MW figure

Part 2 Transmission Entry Capacity

Transmission Entry Capacity (TEC) expressed in average MW taken over a half-hour settlement period

Part 3 BM Units Comprising Power Station

T_FFES-1 (Associated with FFES_01Z)
T_FFES-2 (Associated with FFES_02Z)
T_FFES-3 (Associated with FFES_03Z)
T_FFES-4 (Associated with FFES_04Z)
T_FFES-ST1 (Station Demand)

Using this methodology, the Authority could issue notices for all transmission- connected storage facilities to National Grid.

B The wider scope solution to include transmission generation demand

Whilst the simple solution improves cost reflectivity of the system by exempting transmission-connected storage demand from BSUoS liability, there would be some additional benefit to the wider system by exempting all transmission connected demand used for generation from BSUoS liability. The effects detailed in Appendix 1 would incrementally less than those from storage demand but would still give additional consumer benefit.

Again we believe that a simple solution should be adopted for this methodology by the group and example text is shown below. This is the same as the new original modification proposal.

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A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):

	All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Demand BMUs shall be disregarded. For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology – An Exemptible Demand BMU is a BMU that : is listed in Appendix C of a bilateral connection agreement (BCA) that is associated with a Generation Licence; or is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptible Large power station Agreement (BELLA) above 100MW in size and associated with a Generation Licence; This definition would not be dependent on a storage licence and would apply to all transmission connected demand associated with generation. **C The complete transmission and distribution solution** Whilst we would support the inclusion of embedded storage facilities in a solution, the development of a solution requires significant changes to the current embedded benefits methodology for all embedded generation to ensure that embedded storage is treated the same as transmission storage. Currently embedded storage is roughly neutral to BSUoS as it pays on demand and receives on generation, so it is not as pressing an issue for this type of storage as it is for transmission connected storage. ENGIE raised CMP307 “Expanding the BSUoS charging base to include embedded generation” to start the process of addressing the embedded benefits issue”. Following this. the Authority has indicated that embedded benefits are being reviewed as part of the current TCR SCR and has decided to not allow the progression of CMP 307.

	We believe that there is little point in the group developing a solution for embedded storage (CVA below 100 MW and SVA) without dealing with the wider BSUoS embedded benefits issue which is now being dealt with by Ofgem as part of the TCR SCR.					
Colin Prestwich, Smartest Energy	No. We do not think competition is better served by the proposal because it does not resolve any differences between CVA and SVA. The rationale given for not extending the proposal to SVA as presented on page 13 of the consultation document is specious; a supplier may be charged BSUoS on a net basis, but the demand and generation that make up the supplier's net position are settled by them discretely on the gross impact they have on that net position	No. We are opposed to this. The document states the following: Any implementation date is dependent on gaining a decision from The Authority in the August before the start of a Charging year. Therefore, we would need a decision from the Authority by August 2019 to be able to implement this modification for April 2020. This suggests a mere eight months' notice. Traditionally, pricing modification proposals of this nature have had a longer lead time.	Please see answer to Q6	No	We do not envisage that there will be much of an impact on billing operations.	Page 8 of the consultation document states the following: The proposed solution under the CMP281 modification was discussed in the context of the legislative framework outlined above. The proposal as originally defined required separate identification of storage facilities reflecting the proposed definition of storage under the new form of Generation Licence. In the

						context of the activities permissible under the Electricity Act and the generation licence it became clear the such detailed provisions may not be required as part of the CMP281 solution. Consequently, the CMP281 proposal was refined. It is now based on the removal of “off taking” BSUoS charges from all generation facilities operated under a generation licence. The defect, however, was defined as follows: Under the current Charging

						Methodology, storage providers pay BSUoS on both their import and export volumes (in addition to the BSUoS costs implicit in their 'fuel cost'). Storage providers are therefore contributing more towards the cost of balancing the system than other users. Storage providers, who compete with generators in the provision of ancillary services, are therefore at a competitive disadvantage, which is likely to distort market outcomes and so disadvantage consumers.

						Ironically, therefore, the “refined” proposal reduces charges for generation and storage but does not completely level the playing field between generation and storage as far as charging is concerned, save for the fact that storage would generally have greater levels of import. More generally, the original proposal probably is moving towards Ofgem’s and Govt’s intentions with regards to placing network costs on demand. However, we are inclined to think that the “refined” proposal jumps the gun of

						the TCR. Ofgem recommended in the Targeted Charging Review consultation that changes to charging for storage should be taken forward ahead of any wider changes to residual charging. This proposed solution does not fulfil that requirement.
Paul Jones, Uniper	Yes, subject to clarification of some points we raise in our response to 3 below. It should facilitate objective a) by promoting competition in the wholesale market.	Yes	There seems to be some confusion about the exact solution being proposed in the text. Section 3 on page 6 of the consultation says that section 14.29.4 will be changed to prevent all off-taking Exemptible Storage BMUs from being charged BSUoS. However, section 19 on page 23 implies that all off-taking	No thank you	We do not anticipate a significant implementation issue for ourselves. It is possible that there may be contracts which could be affected, but presumably these will have appropriate regulatory reopener clauses.	It would seem to. A modification which solely looked at removing the charge from storage, but did not introduce equivalent treatment for generation, would have introduced another form of discriminatory treatment.

			BMUs and Trading Units associated with generation operating under a generation licence will be exempt, which seems to be in keeping with other text in the consultation. Our support above is made assuming this latter interpretation. In the text in section 19, reference is made to Demand BMUs. However, this does not seem to be defined anywhere. The text will presumably need to be tidied up generally. For instance, it currently refers to supply “under a Generation licence” which seems to imply that a generation licence directly authorises you to supply when it is the provisions of the			

			Electricity Act which allows this to happen under an exemption. A number of power stations are charged on a Trading Unit basis, so that station demand is netted from any generation at the same station. We assume that the wording in section 19 is aimed at allowing this to continue. Therefore, it is only when the Trading Unit becomes negative, due to station demand being higher than any output during the period, that the charge becomes zero. Accepting that it is always preferable to keep legal text simple, it's not clear from the present drafting that this is indeed the case.			

			The implementation costs for the modification seem quite high. It may be worth exploring whether costs could be reduced by making the changes to systems and processes required for this modification at the same time as any needed under Ofgem's charging review.			
Bill Reed, RWE Supply and Trading	CMP281 will better facilitate CUSC Objective (a). It will remove BSUoS charges from off takes related to electricity generators at facilities (BMUs and Trading Units) where that person is carrying on activities authorised by a Generation Licence. The proposed solution is a non-discriminatory approach towards implementation with	We support the proposed implementation approach for the CMP281 solution. We note that the proposal as originally defined would have required new administrative proposals with respect to the definition of storage in the CUSC which would have been cumbersome	We have no other comments.		The CMP281 solution will have no impact on our billing or contracts and we do not believe that there would be any material implications for tariff stability.	The proposed CMP281 solution ensures that all generation including existing pumped storage generation would be relieved from the obligation to pay off taking BSUoS. This is compatible with the approach taken by BEIS/Ofgem in the designation of storage under the Generation Licence as envisaged in the

	respect to all Generation Licensees. The solution facilitates the BEIS/Ofgem Smart Systems and Flexibility Plan by enabling storage to benefit from the proposed arrangements once the relevant Generation Licence changes are implemented	to implement and difficult to enforce.				Smart Systems and Flexibility Plan.
Paul Youngman, Drax	Yes, we believe that the Original Proposal (removing BSUoS liability on imports from all facilitates supplied under a generation licence) better facilitates the Applicable CUSC Objectives. Applicable CUSC Charging Objective (a) – Positive In addition to the BSUoS costs implicit in their 'fuel cost',	We support implementing CMP281 on the 1st April 2019 to coincide with the start of the Charging Year. If implementation cannot be achieved for the 1st April 2019, CMP281 should be implemented as soon as possible thereafter.	No	No	We believe the main impacts have been captured in the proposal and consultation.	In our view the current proposal has a positive impact on competition and levels the playing field between different types of generation. We believe this is in line with Ofgem intent and the objective of the Smart Systems and Flexibility Plan.

	currently storage providers pay BSUoS on both their import and export volumes. Storage providers are therefore contributing disproportionally towards the cost of balancing the system compared to other generation technologies. This is distorting competition. The removal of BSUoS liability on imports from all generation facilities supplied under a generation licence is a simple and effective solution that will address the defect and better facilitate effective competition in the generation of electricity. Ultimately reducing costs for the end consumer.					

	When the proposal was first raised the solution applied only to imports to storage facilities, this was then amended so the original proposal now includes all facilities supplied under a generation licence. Our preference is for this approach which: □ Levels the playing field by correcting the defect related to storage whilst not introducing any other distortions between different technology types □ Should be relatively easy to implement at least cost to the consumer					
James Anderson, Scottish Power	We believe that the CMP281 Original proposal will better	The Proposal should be implemented in line with the beginning	No	No	As outlined in the Working Group Report, CMP281 will have a	Yes. As outlined in the Working Group Report Section 4.1, CMP281 delivers the change

	facilitate the Applicable CUSC Objectives (ACOs). Storage facility operators are currently liable for BSUoS on both their import and export volumes (in addition to the BSUoS cost implicit in their energy purchase cost). This means that storage operators pay a higher proportion of BSUoS costs than their competitors in the provision of ancillary services. Removing demand BSUoS charges from storage will therefore better facilitate competition (ACO (a)). The Proposal is neutral against the other ACOs	of the first Charging Year following approval – preferably 1 April 2020.			negligible impact on other BSUoS payers. Removing the £12m of BSUoS paid by storage facilities in prior charging years would have increased the average BSUoS charge to others by around £0.02/MWh (0.8%) which is well within the level of forecasting accuracy. As currently drafted, Generation Licence holders will require to satisfy themselves that supply taken at their generation premises are solely associated with the generation activities and certify this to National Grid's BSUoS billing team. As a one-off exercise which relieves the Generation Licence holder of liability for demand BSUoS this should not prove too onerous.	proposed in the Government and Ofgem's Smart Systems and Flexibility Plan (July 2017) and is in line with the direction of travel of Ofgem's work on the TCR/SCR dealing with recovery of residual charges from demand. The analysis within the Workgroup Report indicates that there is currently no effective signal provided by demand BSUoS charges. Removal of demand BSUoS would therefore not be

						detrimental to operation of the transmission system or to consumers. Should a more cost reflective method of recovering BSUoS costs which provides a effective signal be developed under the TCR/SCR then this can be defined and implemented following implementation of CMP281.
Yoanna Vitanova, Renewable UK	No, we do not believe that CMP281 original proposal or any of the identified alternatives would better facilitate the Applicable CUSC Objectives. We are concerned that if implemented the modification would not	No, we do not support the proposed implementation approach as this will unduly favour only one set of generation (large pump hydro).	It is important that network charges do not prevent a level playing field between different providers of flexibility. We are concerned that any future review on BSUoS looking into its	No		Please refer to Q1

	improve competition between supply and generation of electricity, but it would create a benefit for only one type of generation (large pump hydro). The consultation document relies on National Grid Future Energy Scenarios (FES) data suggesting that between 7GW and 10GW of storage would be connected to the grid by 2030, however this accounts for both transmission and distribution connected storage. In fact, the latest FES document predicts transmission connected storage capacity to be comprised up of 4TWh pumped hydro facilities and less than 1TWh battery storage by 2030 in its Community Renewables scenario. This does not present a significant growth from today. Indeed, the consultation itself relies on		cost reflectivity would affect all parties within the energy system, including storage providers. Changes to storage charging should be part of a wider review of BSUoS charge rather than being taken through the piecemeal code governance process. This will allow for a whole system treatment of storage across both transmission and distribution and ensure those facilities have been treated fairly alongside other forms of generation.			

	analysis showing that the pumping volume was approximately 4TWh in 2026/17, representing 0.78% of the total volume (520TWh) liable for BSUoS charges. We are particularly concerned that such misinterpretation would not lead to accurate estimation within the impact assessment of the change proposal and needs to be revised before any further analysis is carried out. Removing BSUoS charging from imports for transmission connected storage is particularly discriminatory against embedded storage facilities with the latter still subject to residual elements of EDCM and CDCM distribution charges. We would like to note that DCP319 and DCP321 change proposals looking to remove residual charges					

	from storage/embedded generation have been withdrawn from DCUSA recently with no alternative being raised. In this context implementing the solution under CMP281 would create a significant distortion in the way storage is treated across transmission and distribution and in itself benefit transmission connected storage facilities only. While we are supportive of the proposals which aim to encourage a level playing field between different providers of flexibility we believe that distributed storage should be treated no differently. Currently there is no alternative proposal which would ensure equal treatment of storage across both transmission and distribution. CMP281 would also have cross-code impacts which have not been considered so far.					

	Thus, it is also important to consider the proposal in the context of these DCUSA modifications as well as other CUSC change proposals looking at reforming the current structure of BSUoS e.g. CMP308. We are mindful that a wider review of BSUoS charging methodology is likely to be raised later on this year separately from the Targeted Charging Review Significant Code Review and Ofgem work under Access and Forward-looking charges. As BSUoS charges are not split into residual and forward-looking elements in the same way as TNUoS and DUoS, such wider review would look at whether certain elements of this charge can be isolated and removed to ensure cost reflectivity. Appropriate charging for					

	storage should be part of a wider review on BSUoS to ensure a wholistic overview of the issues across generation and demand.					
Andrew Colley, SSE plc.	Yes. SSE agrees that the current BSUoS charging regime requires storage providers to contribute more towards the cost of balancing the system than other users, leaving them at a competitive disadvantage when compared to other flexibility providers. Perpetuation of this distortion could hinder the development of new storage projects to help provide flexibility	Yes	SSE support the criteria proposed by the workgroup to determine the scope of Parties that should receive relief against the import charge, i.e. supplies associated with licensed generation activities (including storage). We believe that this greatly simplifies the solution and that it is consistent with the current direction of travel to equitably recover revenue		The main impact for CUSC Parties will be a redistribution of costs as liabilities are removed from licensed storage and generation providers. SSE do not consider the estimated impact of this redistribution (as detailed in Chapter 14 at approx. 2p per MWh) to be significant. It will reduce the operating costs of storage facilities in particular, allowing them to compete on a more level playing field with other flexibility providers to the ultimate benefit of consumers. SSE currently operate a Transmission connected storage facility so would expect to change cost modelling and back-	Yes

	options for the Total System. Electricity storage facilities import electricity from the Transmission System in order to store it for reinjection at an appropriate time to be used by end consumers. The storage facility does not have self-consumption as its primary purpose. The current charging regime therefore can result in double counting of energy to the end consumer - when imported by the storage facility (and considered to be self-consumption); and when exported and recorded as consumption by end		from end-use consumption and ensure a level playing field for flexibility providers. However, we would not want to delay progress of the modification as a result of it being subsumed within the current charging SCR (by virtue of the wider coverage of licensed generators that would benefit). If the workgroup considers this a realistic risk, then SSE would support an alternative that reflects the Original Proposal (i.e. limited to CVA storage facilities) to address the current		office systems to reflect the revised charging arrangement if approved. We estimate that our systems and process costs would be relatively small however, with the majority of the impact falling upon National Grid ESO's and ELEXON's processes and systems.	

	consumers. This adds to the costs of operation of storage, resulting in a competitive distortion which may also result in additional costs being passed through to end consumers. SSE believes that the proposal will remove a distortion in competition between different types of energy producers, ensuring that certain users do not pay disproportionate costs, resulting in a fairer allocation of costs and thereby better facilitating applicable objective a)		disadvantage for storage operators, as opposed to the Amended Original.			
Urmi Mistry, NGESO	We believe the proposed original (applicable to storage only) and the amended solution	If this modification is approved, we would support the approach detailed on page 15 of	We have a few comments for the workgroup to consider:	Not at this point in time. However, it should be noted that DCUSA modification	Impact on NGESO: • We have detailed the high-level system changes required for NGESO in the System	In our view, the original proposal will not level the playing field in the

	(applicable to all generation) creates some unintended consequences and so does not better facilitate the applicable CUSC objectives: • Objective (a) – This modification will have a negative impact on this objective. Regarding the original proposal of storage only, it is discriminatory in nature. Storage will be exposed to less use of system costs than other forms of generation creating a market distortion potentially limiting competition. Where the modification solution is applicable to all generation, this has a marginally less negative impact on this objective. This solution may also conflict with the outcomes of Ofgem's Significant Code Review (SCR) into residual charging and as such it is difficult to assess whether it	the consultation document ('Implementation Information') and in section 7. This would only be practical if there was an Authority decision in the July/August before the start of a Charging Year. If a decision is received later than July/August 2019 then implementation should be no earlier than April 2021, owing to the significant system changes required to facilitate this CMP.	1. Further considerations for the Workgroup: We feel that the fundamental issue is with the BSUoS charging methodology, its principles and how it is calculated; therefore, this needs to be considered and is vitally important to this modification. The defect and issues analysed by the workgroup highlight the fact that the current BSUoS methodology is not appropriate for the electricity system of today. This is highlighted within the 'wider defect' section, on page 11 of the consultation document, which mentions the counter intuitive nature of BSUoS where	DCP319 and DCP321 are being narrowed in scope following a letter from Ofgem. Both look to address the same issues as CMP280 and CMP281 but on the distribution network. This should be noted as this modification may receive the same direction from Ofgem, following the increase in scope to all generation. Also, that if CMP281 were approved it will create a further distortion between the transmission and distribution charging arrangements if these DCUSA modifications are not also approved.	changes section of consultation document (page 15 of the report). • How we identify these units is not clear from the consultation document and needs to be fully considered. It may be that Elexon would be more easily able to identify these sites and therefore a consequential BSC modification would be necessary to ensure data is provided to the ESO at lowest cost overall to the end consumer.	way that Government and Ofgem intended in recent publications. It would be prudent to wait for more information to be published by Ofgem on the TCR SCR before this modification goes any further. • In July 2017 Ofgem & BEIS published 'Upgrading our Energy System – Smart Systems and Flexibility Plan'. In this document, they stated 'These views are that storage facilities should not pay the 'demand residual' element of network charges at transmission and distribution level, and that storage providers should

	is appropriate to take this proposal forward at this time. • Objective (b) – As it currently stands this modification will have a negative impact on this objective because it would cause a breach of Transmission Licence Condition C26. This condition states that 'The licensee shall use all reasonable endeavours to ensure that in its application of the use of system charging methodology in accordance with standard condition C5 (Use of system charging methodology), use of system charges resulting from transmission constraints costs are treated by the licensee such that the effect of their recovery is shared on an equal per MWh basis by all parties liable for use of system charges' (as stated		behaviour by parties which is beneficial for the network, is penalised. This is another fundamental question which needs further consideration as this modification will only redistribute the cost incurred in any one settlement period to a smaller number of parties and so exacerbate the wider defect. In October NGESO ran a series of Workshops to start a wider piece of work to consider BSUoS in more detail and begin a larger reform of the BSUoS charge. We feel this is a better route to address the questions surrounding treatment of storage in a more holistic and non-discriminatory manner. There is also			only pay one set of balancing system charges.' Therefore, this modification would be fulfilling this intention as indicated by Ofgem & BEIS. • However, the modification does not consider the update in Ofgem's position and the possibility of a forward-looking element (if found). Following Ofgem's Storage Charging Summary note (Feb 2018) publication (as noted in the consultation document), storage should pay forward-looking charges on both import and export. This modification, at present, will not

	on page 22 of the consultation document). This modification would cause BSUoS liable parties (generators and suppliers) to pay unequal amounts as only a portion of BSUoS costs are removed from liable parties. Therefore, if this modification were approved this would cause a breach of licence for the transmission owner. To avoid this occurring the licence condition would need to be updated. • Objective (c) – neutral • Objective (d) – neutral • Objective (e) – There will be a negative impact on this objective. If the proposal is implemented as suggested/discussed by the workgroup so far, it will introduce complexity in administration and implementation of the CUSC. The proposed process suggested on		a significant amount of industry work underway that will materially affect the direction of this modification and BSUoS, such as the TCR SCR, Access & Forward Looking Charges reform and the Storage Licence Consultation (which is still awaiting decision from November 2017). All of these things will impact the BSUoS methodology fundamentally and so any solutions proposed as part of this modification may become redundant in the future or create larger distortions as results from these larger pieces of work become clear. The CUSC modification process dictates that the			facilitate this. If a forward-looking element is found within BSUoS, under this modification storage (and possibly all generation) will pay no form of BSUoS on their imports at all. As the solution is not clear for this modification, it could result in multiple changes being needed in the future (change upon change etc…) which will reduce certainty in the market and impact competition. • The proposal also does not consider Ofgem's work on the TCR SCR or Access & Forward Looking charges fully. They are

	page 8 of the report, is that National Grid are notified of which BMUs are owned by a Licence holder and then the exemption is applied by National Grid to these units. This process at a high level would require significant changes to IT systems resulting in substantial implementation costs. This process would involve a new system to; o maintain a register of relevant generators/BMUs, o quality assure the data in the register, o synchronise the register with Elexon's Central Registration Agency, o interface and provide data to existing systems from the register, e.g. daily submissions of data to the Charging and Billing (CAB) system and so a new input source and consequential		baseline is used to assess proposals against, however this modification overlaps with other work-streams which aim to make a fundamental change to current arrangements. So, to ensure the solution is future-proof and fit for purpose, these areas of work need to be considered within the solution. Additionally, NGESO are not allowed, under our Licence, to unduly discriminate between any persons, class or classes of persons (Licence Condition C7 'Prohibition on discriminating between users'). There has been no clear direction from Ofgem that Storage should be treated uniquely from any other form of			looking at residual charges and suggest wider areas of BSUoS need to be looked at. This work will have a knock-on impact to this change proposal. Aligning with this work will ensure that arrangements put in place for generation will be equivalent with arrangements for storage parties. • This modification doesn't address BSUoS embedded benefits issue. Ofgem have noted that other embedded benefits will be kept under review and so waiting for further direction from Ofgem on how this will be addressed

	changes to internal systems. New processes will also need to be established to support the new system such as dispute, data error assurance and data correction. This would replicate a process already carried out by Elexon during the BMU registration process. Therefore, the workgroup should consider this when looking at implementation as this would be the more efficient option and have the lowest overall cost to the consumer.		generation, this is also not reflected or evidenced in the report strongly enough. Therefore, by applying BSUoS to a certain group of industry parties mainly based on differing business costs (fuel cost in proposal form) cannot be used as a strong enough reason to discriminate. There is currently a storage licence consultation which is with Ofgem for decision. This consultation looks to introduce regulatory arrangements for storage into the Generation Licence. This closed in November 2017 and is still awaiting a decision. This further adds to the argument that Storage is no			will be beneficial for this modification when looking to create a solution.

			different from any other form of generation. If the proposal goes ahead with the updated solution covering all generation, there will be discrimination between transmission connected and embedded generation and between generation and demand/supply parties. Therefore, this should be considered further. The current direction of travel of CMP281 uses the Licence as a basis to identify those parties who are liable for BSUoS and those who aren't. The Licence refers to a legal entity rather than a specific generating station or BMU. Therefore, this will be complex to implement			

			for the BSUoS methodology as currently BSUoS is calculated on a Trading Unit/BMU basis. There has been no clear way for NGESO to be able to use this information to clearly identify these units without significant costs incurred and inefficient processes introduced. This process of identifying the exemptible parties needs further consideration. Another aspect that is mentioned on page 21 of the report is the Public Service Obligation (PSO), which states that costs are spread equally across parties and links to the Transmission Licence Condition C26			

			(applicable CUSC objective (b)). The PSO is something that needs to be considered further by the workgroup and steps should put in place to address it. If this is not done before this modification is implemented, then NGESO will be in breach of its Licence 1. Another area to consider is that Ofgem published their decision on CMP250 on the 25th October 2018. Ofgem rejected this modification but made suggestions on further work regarding BSUoS, such as future assessment of the components of BSUoS and evaluating their impact, whether they are cost recovery/cost reflectivity and			

			consideration of impacts wider than the CUSC e.g. licence impacts. Therefore, it would be prudent to ensure these areas are considered and clear within the report to give Ofgem as much information as possible as to whether this modification will have an impact on the components of BSUoS. Modification GC0096 is referenced in the consultation document on page 17 which looks to introduce technical requirement for Storage. This Grid Code modification has moved on since this section was written and poses some questions which need consideration: o The proposed definition of 'Electricity			

			Storage Facility' excludes Pumped Storage. This is a concern as it creates a new category on the same level as Power Station and so this will need to be reflected in the CUSC. To keep definition consistent across codes, this exclusion of Pumped Storage would mean that any solution created under CMP281 and assuming the definitions aligned with the Grid Code, the Pumped Storage stations defined in the Grid Code will still be liable for use of system charges. Therefore, the addition of 'Electricity Storage Facility and Pumped Storage' should solve this issue within the CUSC.			

			We encourage the proposer and any proposers of alternatives to ensure this is captured within their solution. 2. General Comments The figures presented in the report looking at material impact of this modification, consumer impact and impact on RCRC (residual cashflow reallocation cashflow) do not consider the future network and the predicted increase from 3GW of storage on the system to between 7GW and 10GW by 2030. Therefore, the numbers presented in the report do not provide any future estimation of the impact of this modification (Annex 2, impact on consumers			

			and materiality sections) therefore it is hard to understand the impacts of this modification, true cost to industry parties and to the end consumer fully. This modification, at present, doesn't have a clear solution or clear understanding of how this will be implemented, therefore this needs to be fully considered by the workgroup and noted so it is clear to Ofgem and industry. We are of the view that a much broader reform of the BSUoS methodology is needed, it will have longer term benefits and be more valuable for all industry parties and consumers. It will also create a charging arrangement that is fit			

			for purpose, clear and transparent.			
Nicola Percival, Innogy	No. innogy does not see that the implementation of CMP281 would better facilitate any of the CUSC objectives. If implemented this modification would positively discriminate to benefit only licenced storage connected to the transmission network, of which only pumped storage is currently identifiable as 'storage' in the generation licence. There were two DCUSA change proposals looking to remove residual charges from storage/embedded generation – DCP319 and DCP321. These were broadly the DCUSA's version of CMP280 and CMP281. We note that the DCUSA proposals have both had proposer support withdrawn, this coming swiftly after a direction from	We do not support the modification, and so we do not support the implementation approach either.	It is important that network charges do not prevent a level playing field between different providers of flexibility. Any future review on BSUoS looking into its cost reflectivity / who should pay BSUoS would affect all parties within the energy system, regardless of where on the network they connect. Changes to charging for storage should be part of this wider review of BSUoS charging rather than being taken through the piecemeal code governance process, particularly where piecemeal changes would create further distortion. This will allow for a whole	No		No. CMP281 would create new distortion rather than levelling the playing field. The workgroup discussions have been eye-opening in discovering the complexity and interlinkedness of these modifications with broader policy (eg the Smart Systems Plan, BSUoS PSO) and, in innogy's view, have shown that a standalone CUSC Mod is an inappropriate way to explore further how the playing field can truly be levelled. These issues are better suited to a more

	Ofgem that CMP280, DCP319 and DCP321 should apply to storage only and not all generation. The reason for the withdrawal of support is that the proposer felt that removing residual charging for storage only (not generation more broadly) would create a distortion between storage and all other embedded generation. No workgroup members for DCP319/321 chose to support these proposals or raise alternatives following Ofgem's letter and the proposer's withdrawal of support. Innogy feels that the proposer of CMP281 (and CMP280) should follow suit given that this modification will create a similar distortion1. Ofgem have made it clear that they "reserve the option, if necessary, of bringing storage charges back into the TCR SCR…"2. Innogy		system treatment of storage across both transmission and distribution and ensure those facilities have been treated fairly alongside other forms of generation. In addition, we note that in all four of the FES scenarios from 2018 pumped storage is assumed not to contribute many more TWh than today: "Very little opportunity for new pumped storage sites that haven't already been developed"3 and transmission-connected storage of any kind is not expected to increase much by 2030. On page 14 of the workgroup consultation the Proposer refers to FES data that between			formal review, which is not a priority over the current TCR and upcoming SCR. Please refer to our answers to Questions 1 and 3 for full detail.

	encourages Ofgem to do so. Innogy are supportive of proposals which would level the playing field for all types of network users across both transmission and distribution networks. However CMP281 does not do this. The identified defect is indicative of a much deeper set of issues related to broader policy (eg the Smart Systems Plan, BSUoS PSO), which is much wider than just the CUSC and DCUSA. It is important that the workgroup, and especially Ofgem, considers CMP281 in the context of the withdrawn DCUSA modifications as well as other CUSC change proposals looking at reforming the current structure of BSUoS e.g. CMP308 and the TCR SCR and upcoming SCR.		7GW and 10GW of storage would be connected to the grid by 2030. The statement is correct but this accounts for all types of storage, connected at both transmission and distribution. The estimation of the impacts of CMP281, should it be implemented, appears to have been calculated based on historic data, but the inference that this could become more significant over time is flawed and misleading. Innogy are also concerned about the wording used in the Smart Systems and Flexibility Plan: Progress Update. In Annex A, action 1.1, under			

			‘What we will do next’ it states: “Industry will finalise charging code modifications to address the storage issues identified in the Plan, and it is expected that these will be submitted promptly to Ofgem for approval.” This suggests that Ofgem is predisposed to approve the modifications CMP280 and CMP281 before the workgroup and consultation phases are finalised.			

6 Workgroup Vote

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

The Workgroup met on 18 June 2019 and voted on whether the Original would better facilitate the Applicable CUSC Objectives than the baseline and what option was best overall.

The Workgroup voted against the Applicable CUSC Charging Objectives for the Original Proposal. The Workgroup voted and concluded that the Original Proposal is better than Baseline.

Vote 1 – *does the original facilitate the objectives better than the Baseline?*

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)	Better facilitates ACO (c)	Better facilitates ACO (d)	Better Facilitates ACO €	Overall (Y/N)
	Paul Youngman – Drax					
Original	***Y***	***Y***	***Neutral***	***N/A***	***Y***	***Y***
Voting Statement	We agree that the reformulated original solution is still better for competition and efficiency of the arrangements when compared with the baseline arrangements.					
	Andy Colley - SSE					
Original	***Y***	***Neutral***	***Neutral***	***Neutral***	***Neutral***	***Y***
Voting Statement	The current BSUoS charging regime exposes Storage providers to greater risks and costs of balancing the system than other users and technology types, leaving them at a competitive disadvantage. Perpetuation of this distortion could limit the development of Storage projects and thus flexibility options to balance the system in an economic and efficient way. The solution will remove this distortion in competition between different types of energy producers, resulting in a more efficient allocation of costs and thereby better facilitating ACO a).					
	Harriet Harmon – National Grid ESO					

Original	***Y***	***Neutral***	***Neutral***	***Neutral***	***Neutral***	***Y***
Voting Statement	Provided that: a) BSC P383 delivers a solution for the exchange of information between relevant market participants; and b) The separate CUSC Modification Proposal, raised by the Proposer of this CMP281, seeking to introduce new defined terms into S11 CUSC is approved; and c) The ESO's licence is changed such that C26 no longer refers to 'parties' liable for BSUoS in relation to constraint cost recoveries, this CMP should deliver a benefit to competition through resolution of the issue that storage pays BSUoS directly on import and export (as applicable). However: I am mindful of CMP308 which, if approved alongside this CMP281 and CMP280 would mean Storage providers would pay only the TNUoS demand locational, and the generator locational. Other generators would pay the full TNUoS demand tariff, generator locational, and BSUoS on exports - over time it may be necessary to reconsider the propriety of charging arrangements for different classes of licensed generators. As a standalone CMP, 281 is marginally better on ACO (a) than baseline (to the limited extent of storage) but cumulatively there is a risk that the overall arrangements for storage do not better facilitate competition. Separately, this CMP is incompatible with C26 of our (ESO's) licence which requires that the costs of constraints are shared equally between all parties liable for BSUoS. If C26 is not amended prior to any Authority approval of this CMP281, the CUSC and Licence will be in direct conflict. This CMP is currently therefore worse against ACO (b) than baseline, but given the extent to which Ofgem and BEIS have engaged in this mod process, it is anticipated that the conflict between CUSC and licence would be resolved prior to any implementation of changes.					
	Simon Vicary – EDF Energy					
Original	***Y***	***Neutral***	***Neutral***	***Neutral***	***Neutral***	***Y***
Voting Statement	Ofgem state in their TCR consultation (published 13th March 2017 paragraph 1.31) "We think that the way charges affect storage at present create a relative disadvantage for storage operators, in comparison with generators connected at the same voltage level"…." This is because…transmission-connected storage pays BSUoS as both demand and generation. In					

	order to secure a more level playing-field, we think that storage should be liable to pay only….one set of BSUoS charges." Given Ofgem's statement in the above cited extract we believe that the Original Proposal delivers an appropriate solution.					
	Simon Lord – Engie (Proposer)					
Original	***Y***	***Y***	***Y***	***Neutral***	***Y***	***Y***
Voting Statement	As a principle cost recovery charges should only be recovered from end consumption so as not distort competition, established economic theory supports this position. In the energy market BSUoS is considered a cost recovery charge, a resent in-depth look at this via the BSUoS task force has confirmed this position. Removing BSUoS from storage demand (intermediate demand) will lead to improved consumer benefits. Currently BSUoS is considered to be sending an inappropriate signal to overnight demand (and storage) driven by the technical design of the cost recovery mechanism. We therefore agree that the Original modification facilitate the CUSC objectives against the baseline and will ultimately lead to benefits to consumers driven by lower energy prices					
	Robert Longden – Cornwall Energy					
Original	***Y***	***Neutral***	***Neutral***	***Neutral***	***Neutral***	***Y***
Voting Statement	The proposal is consistent with Ofgem's statement regarding the treatment of storage facilities and BSUoS charges					
	Bill Reed – RWE					
Original	***Y***	***Y***	***Y***	***Neutral***	***Y***	***Y***
Voting Statement	CMP281 will facilitate the deployment of storage facilities and enhance competition in the electricity market. However, it introduces a distortion in treatment under the CUSC with regard to the charging arrangements and Generation Licensees. Those with a storage facility will receive a benefit that is unavailable to other generation licensees. Given the current structure of charges the impact is likely to not be material. However, if the charging arrangements were to change significantly under the various Ofgem reviews of network charges then this issue may need to be revisited					

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

Workgroup Member	BEST Option?
Paul Youngman – Drax	**Original**
Andy Colley - SSE	**Original**
Harriet Harmon – National Grid ESO	**Original**
Simon Vicary – EDF Energy	**Original**
Simon Lord – Engie (Proposer)	**Original**
Robert Longden – Cornwall Energy	**Original**
Bill Reed – RWE	**Original**

7 CMP281: Relevant Objectives

Impact of the modification on the Applicable CUSC Objectives (Charging):	
Relevant Objective	Identified impact
(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	Positive. Removing a distortion in competition will better facilitate competition.
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	Positive/None As BSUoS charges are not intended to be cost reflective, this proposal will have little impact on cost reflectivity other than removing a distortion whereby some users pay a disproportionate amount of the costs.
(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably	None

practicable, properly takes account of the developments in transmission licensees' transmission businesses;	
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1 *; and	None
(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.	None
*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).	

8 Implementation

The Proposal, if approved, should be implemented to coincide with the start of a Charging Year (i.e. 1 April) and should be implemented in the first practical Charging Year following a decision by the Authority. If an Authority decision is available in time, the change could be implemented no earlier than 1 April 2021. The Workgroup noted that there may be an impact on Suppliers from an early implementation date however considered that the April 2021 is being offered as the earliest practical date. One Workgroup member suggested 1 April 2022. The Workgroup agreed that the implementation date is a decision for the Authority.

9 Legal Text

The Finalised Legal text is in Annex 2 of this report.

10 Annex 1: CMP281 Terms of Reference

nationalgrid

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP281 WORKGROUP

CMP281 aims to remove liability from storage facilities for Balancing Services Use of System (BSUoS) charges on imports.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP281 'Removal of BSUoS Charges From Energy Taken From the National Grid System by Storage Facilities'** raised by **Scottish Power** at the Modifications Panel meeting on 30 June 2017.

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

Charging Applicable Objectives

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

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

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

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

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

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) Consider co-location of generation and storage assets
   b) Consider the practical implications of solution e.g. that all metered data is available to National Grid to support the proposed solution
   c) Consider the impacts on RCRC and BSC arrangements
   d) Consider the interaction with CMP250
   e) Consider impacts on foot-room, High Frequency Response and fuel equivalency (e.g. battery and conventional generation).

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 **7 December 2017** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **15 December 2017**.

Membership

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

Role	Name	Representing
Chairman	Caroline Wright	Code Administrator
National Grid Representative	Urmi Mistry	National Grid
Industry Representatives	Rupert Steele James Anderson Bill Reed Robert Longden Libby Glazebrook Paul Mott Andrew Colley Paul Youngman Fruzina Kemenes	Scottish Power (Proposer) Scottish Power RWE Cornwall Energy Engie EDF Energy SSE Drax Innogy
Authority Representatives	Judith Ross	OFGEM
Technical secretary	Heena Chauhan	Code Administrator
Observers	Nicholas Rubin	ELEXON

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 CMP281 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 - Timetable

Workgroup Stage

22 June 2017	CUSC Modification Proposal submitted
30 June 2017	Modification Presented to the Panel
30 June 2017	Request for Workgroup Members (10 working days)
w/c 31 July 2017	Meeting 1 via WebEx to ensure Workgroup members have a fully understanding of the context of the modification
w/c 18 September 2017	Circulate draft Workgroup Report
September to March 2018	Workgroup Meetings – Develop Proposal
April 2018	Workgroup Consultation issued to the Industry (15WD)
May 2018 to July 2018	Workgroup Meeting - Workgroup review consultation responses, agree options, finalise legal text and WG vote
August 2018	Workgroup Report issued to CUSC Panel
August 2018	CUSC Panel meeting to discuss Workgroup Report

Code Administrator Stage

September 2018	Code Administration Consultation Report issued to the Industry (15 WD)
October 2018	Draft FMR published for industry comment (3 Working days)
November 2018	Draft Final Modification Report presented to Panel
November 2018	CUSC Panel Recommendation vote
December 2018	Final Modification Report issued the Authority
January/February 2019 *	Indicative Decision for the Authority
1 April 2019 or 1 April 2020	Decision implemented in CUSC

* Note to allow for system changes to be made a decision by Summer 2018 is required.

11 Annex 2: Legal Text

CUSC - SECTION 14

CHARGING METHODOLOGIES

CONTENTS

CUSC - SECTION 1

CHARGING METHODOLOGIES

14.1 Introduction

14.1.1 This section of the CUSC sets out the statement of the Connection Charging Methodology and the Statement of the Use of System Methodology

Part 1 - The Statement of the Connection Charging Methodology

14.2 Principles

Costs and their Allocation

14.2.1 Connection charges enable The Company to recover, with a reasonable rate of return, the costs involved in providing the assets that afford connection to the National Electricity Transmission System.

14.2.2 Connection charges relate to the costs of assets installed solely for and only capable of use by an individual User. These costs may include civil costs, engineering costs, and land clearance and preparation costs associated with the connection assets, but for the avoidance of doubt no land purchase costs will be included..

14.2.3 Connection charges are designed not to discriminate between Users or classes of User. The methodology is applied to both connections that were in existence at Vesting (30 March 1990) and those that have been provided since.

Connection/Use of System Boundary

14.2.4 The first step in setting charges is to define the boundary between connection assets and transmission system infrastructure assets.

14.2.5 In general, connection assets are defined as those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party (i.e. “single user assets”). For the purposes of this Statement, all connection assets at a given location shall together form a connection site.

14.2.6 Connection assets are defined as all those single user assets which:

a) for Double Busbar type connections, are those single user assets connecting the User’s assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay;

b) for teed or mesh connections, are those single user assets from the User’s assets up to, but not including, the HV disconnector or the equivalent point of isolation;

c) for cable and overhead lines at a transmission voltage, are those single user connection circuits connected at a transmission voltage equal to or less than 2km in length that are not potentially shareable.

14.2.7 Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are single user assets under the same Bilateral Connection Agreement.

14.2.8 Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets. For example, in England & Wales NGET does not normally own busbars below 275kV, where The Company and the customer agree that NGET will own the busbars at a low voltage

substation, the assets at that substation will be classed as connection assets and will not automatically be transferred into infrastructure.

14.2.9 The design of some connection sites may not be compatible with the basic boundary definitions in 14.2.6 above. In these instances, a connection boundary consistent with the principles described above will be applied.

14.3 The Calculation of the Basic Annual Connection Charge for an Asset

Pre and Post Vesting Connections

14.3.1 Post Vesting connection assets are those connection assets that have been commissioned since 30 March 1990. Pre Vesting connection assets are those that were commissioned on or before the 30 March 1990.

14.3.2 The basic connection charge has two components. A non-capital component, for which both pre and post vesting assets are treated in the same way and a capital component for which there are slightly different options available for pre and post vesting assets. These are detailed below.

Calculation of the Gross Asset Value (GAV)

14.3.3 The GAV represents the initial total cost of an asset to the transmission licensee. For a new asset it will be the costs incurred by the transmission licensee in the provision of that asset. Typically, the GAV is made up of the following components:

Construction Costs - Costs of bought in services
Engineering - Allocated equipment and direct engineering cost
Interest During Construction – Financing cost
Liquidated Damages Premiums - Premium required to cover Liquidated Damages if applicable.

Some of these elements may be optional at the User's request and are a matter of discussion and agreement at the time the connection agreement is entered into.

14.3.4 The GAV of an asset is re-valued each year normally using one of two methods. For ease of calculation, April is used as the base month.

- In the Modern Equivalent Asset (MEA) revaluation method, the GAV is indexed each year with reference to the prevailing price level for an asset that performs the same function as the original asset;

- In the RPI revaluation method, the original cost of an asset is indexed each year by the Retail Price Index (RPI) formula set out in paragraph 14.3.6. For Pre Vesting connection assets commissioned on or before 30 March 1990, the original cost is the 1996/97 charging GAV (MEA re-valued from vesting). The original costs of Post Vesting assets are calculated based on historical cost information provided by the transmission licensee's.

14.3.5 In the MEA revaluation method, the MEA value is based on a typical asset. An MEA ratio is calculated to account for specific site conditions, as follows:

- The outturn GAV (as calculated in paragraph 14.3.4 above) is re-indexed by RPI to the April of the Financial Year the Charging Date falls within;

- This April figure is compared with the MEA value of the asset in the Financial Year the Charging Date falls within and a ratio calculated;

- If the asset was commissioned at a Connection Site where, due to specific conditions, the asset cost more than the standard MEA value, the ratio would be greater than 1. For example, if an asset cost 10% more to construct and commission

than the typical asset the MEA ratio would be 1.1. If, however, the asset was found only to cost 90% of the typical MEA value the ratio would be 0.9;

- The MEA ratio is then used in all future revaluations of the asset. The April GAV of the asset in any year is thus the current MEA value of the asset multiplied by the ratio calculated for the Financial Year the Charging Date falls within.

14.3.6 The RPI revaluation method is as follows:

- The outturn GAV (as calculated in paragraph 14.3.4 above) is re-indexed by RPI to the April of the Financial Year the Charging Date falls within. This April GAV is thus known as the Base Amount;

- The Base Amount GAV is then indexed to the following April by using the RPI formula used in The Company's Price Control. April GAVs for subsequent years are found using the same process of indexing by RPI.

  i.e. $GAV_n = GAV_{n-1} * RPI_n$

- The RPI calculation for year n is as follows:

$$RPI_n = \frac{[\text{ May to October average RPI Index }]_{n-1}}{[\text{ May to October average RPI Index }]_{n-2}}$$

Calculation of Net Asset Value

14.3.7 The Net Asset Value (NAV) of each asset for year n, used for charge calculation, is the average (mid year) depreciated GAV of the asset. The following formula calculates the NAV of an asset, where A_n is the age of the asset (number of completed charging years old) in year n:

$$NAV_n = GAV_n * \frac{\text{Depreciation Period} - (A_n + 0.5)}{\text{Depreciation Period}}$$

14.3.8 In constant price terms an asset with an initial GAV of £1m and a depreciation period of 40 years will normally have a NAV in the year of its commissioning of £0.9875m (i.e. a reduction of 1.25%) and in its second year of £0.9625m (i.e. a further reduction of 2.5% or one fortieth of the initial GAV). This process will continue with an annual reduction of 2.5% for each year of the asset's life.

Capital Components of the Connection charge for Post Vesting Connection Assets

14.3.9 The standard terms for a connection offer will be:

- 40 year life (with straight line depreciation);

- RPI indexation

14.3.10 In addition a number of options exist:

- a capital contribution based on the allocated GAV at the time of commissioning will reduce capital. Typically a capital contribution made in advance of or at the time of

commissioning will include costs to cover the elements outlined below and charges are calculated as set out in the equations below;

- Construction costs
- Engineering costs (Engineering Charge x job hours)
- Interest During Construction (IDC)
- Return element (6%)
- Liquidated Damages Premium (LD) (if applicable)

General Formula:

Capital Contribution Charge = (Construction Costs + Engineering Charges) x (1+Return %) + IDC + LD Premium

- MEA revaluation which is combined with a 7.5% rate of return, as against 6% on the standard RPI basis;

- annual charges based on depreciation periods other than 40 years;

- annuity based charging;

- indexation of GAVs based on principles other than MEA revaluation and RPI indexation. No alternative forms of indexation have been employed to date.

14.3.11 For new connection assets, should a User wish to agree to one or more of the options detailed above, instead of the standard connection terms, the return elements charged by the transmission licensee may also vary to reflect the re-balancing of risk between the transmission licensee and the User. For example, if Users choose a different indexation method, an appropriate rate of return for such indexation method will be derived.

14.3.12 A User can choose to make a capital contribution based on the allocated and depreciated NAV of a commissioned asset. For a capital contribution to take account at the start of charging year n, the User may, at most once per year, make a full or partial capital contribution of at least 10% of the NAV prevailing as of 31st March in year n-1. The User shall notify the Company of the capital contribution amount no later than 1st September in year n-1, and pay the capital contribution 45 days prior to the start of charging year n which will be applied to the NAV prevailing at the start of year n. As the capital component of the connection charge for year n will reduce as a result of the capital contribution, a reduced rate of return element will be payable and a lower security requirement will be required in charging year n and subsequent years.

Capital Components of the Connection charge for Pre Vesting Connection Assets

14.3.13 The basis of connection charges for GB assets commissioned on or before 30 March 1990 is broadly the same as the standard terms for connections made since 30 March 1990. Specifically charges for pre vesting connection assets are based on the following principles:

- The GAV is the 1996/97 charging GAV (MEA re-valued from vesting) subsequently indexed by the same measure of RPI as used in The Company's Price Control;

- 40 year life (with straight line depreciation);

- 6% rate of return

14.3.14 Pre-vesting 1996 MEA GAVs for Users' connection sites are available from The Company on request from the **Charging Team**.

Non-Capital Components - Charging for Maintenance and Transmission Running Costs

14.3.15 The non-capital component of the connection charge is divided into two parts, as set out below. Both of these non-capital elements will normally be identified in the charging appendices of relevant Bilateral Agreements.

Part A: Site Specific Maintenance Charges

14.3.16 This is a maintenance only component that recovers a proportion of the costs and overheads associated with the maintenance activities conducted on a site-specific basis for connection assets of the transmission licensees.

14.3.17 Site-specific maintenance charges will be calculated each year based on the forecast total site specific maintenance for NETS divided by the total GAV of the transmission licensees NETS connection assets, to arrive at a percentage of total GAV. For 2010/11 this will be 0.52%. For the avoidance of doubt, there will be no reconciliation of the site-specific maintenance charge.

Part B: Transmission Running Costs

14.3.18 The Transmission Running Cost (TRC) factor is calculated at the beginning of each price control to reflect the appropriate amount of other Transmission Running Costs (rates, operation, indirect overheads) incurred by the transmission licensees that should be attributed to connection assets.

14.3.19 The TRC factor is calculated by taking a proportion of the forecast Transmission Running Costs for the transmission licensees (based on operational expenditure figures from the latest price control) that corresponds with the proportion of the transmission licensees' total connection assets as a function of their total business GAV. This cost factor is therefore expressed as a percentage of an asset's GAV and will be fixed for the entirety of the price control period. For 2010/11 this will be 1.45%.

14.3.20 To illustrate the calculation, the following example uses the average operating expenditure from the published price control and the connection assets of each transmission licensee expressed as a percentage of their total system GAV to arrive at a GB TRC of 1.45%:

Example:

Connection assets as a percentage of total system GAV for each TO:

Scottish Power Transmission Ltd	15.1%
Scottish Hydro Transmission Ltd	8.6%
NGET	12.5%

Published current price control average annual operating expenditure (£m):

Scottish Power Transmission Ltd	29.1
Scottish Hydro Transmission Ltd	11.3
NGET	295.2

Total GB Connection GAV = £2.12bn

GB TRC Factor = (15.1% x £29.1m + 8.6% x £11.3m + 12.5% x £295.2m) / £2.12bn

GB TRC Factor = 1.99%

Net GB TRC Factor = Gross GB TRC Factor – Site Specific Maintenance Factor*

Net GB TRC Factor = 1.99% - 0.54% = 1.45%

* Note – the Site Specific Maintenance Factor used to calculate the TRC Factor is that which applies for the first year of the price control period or in this example, is the 2007/8 Site Specific Maintenance Factor of 0.54%.

The Basic Annual Connection Charge Formula

14.3.21 The charge for each connection asset in year n can be derived from the general formula below. This is illustrated more fully by the examples in **Appendix 2: Examples of Connection Charge Calculations.**

$$\text{Annual Connection Charge}_n = D_n\,(GAV_n) + R_n\,(NAV_n) + SSF_n\,(RPIGAV_n) + TC_n\,(GAV_n)$$

Where:

For n = year to which charge relates within the Depreciation Period

n = year to which charge relates
GAV_n = GAV for year n re-valued by relevant indexation method
$RPIGAV_n$ = GAV for year n re-valued by RPI indexation
NAV_n = NAV for year n based on re-valued GAV_n
D_n = Depreciation rate as percentage (equal to 1/Depreciation Period) (typically 1/40 = 2.5% of GAV)
R_n = real rate of return for chosen indexation method (6% for RPI indexation, 7.5% for MEA Indexation)
SSF_n = Site Specific Factor for year n as a % (equal to the Site Specific Cost/Total Site GAV)
TC_n = Transmission Running Cost component for year n (other Transmission Owner Activity costs).

For n = year to which charge relates beyond the Depreciation Period

n = year to which charge relates
GAV_n = GAV for year n re-valued by relevant indexation method
$RPIGAV_n$ = GAV for year n re-valued by RPI indexation
NAV_n = 0
D_n = 0
R_n = real rate of return for chosen indexation method (6% for RPI indexation, 7.5% for MEA Indexation)
SSF_n = Site Specific Factor for year n as a % (equal to the Site Specific Cost/Total Site GAV)
TC_n = Transmission Running cost component for year n (other Transmission Owner Activity costs).

14.3.22 Note that, for the purposes of deriving asset specific charges for site-specific maintenance, the RPI re-valued GAV is used. This is to ensure that the exact site charges are recovered from the assets at the site. The site costs are apportioned to the assets on the basis of the ratio of the asset GAV to total Site GAV.

Adjustment for Capital Contributions

14.3.23 If a User chooses to make a 100% capital contribution (either pre-commissioning or post-commissioning) to The Company towards their allocation of a connection asset then no capital charges will be payable and hence the connection charges for that asset would be calculated as follows:

$$\text{Annual Connection Charge}_n = SSF_n\ (RPIGAV_n) + TC_n\ (GAV_n)$$

14.3.24 If a User chooses to make a partial capital contribution(s) (either pre-commissioning or post-commissioning) to The Company towards their allocation of a connection asset, for example PCCF = 50%, then the connection charges for that asset would be calculated as follows:

$$\text{Annual Connection Charge}_n = D_n\ (GAV_n{*}PCCF) + R_n\ (NAV_n{*}PCCF) + SSF_n\ (RPIGAV_n) + TC_n\ (GAV_n)$$

PCCF = Partial Capital Contribution Factor taking into account a capital contribution made pre-commissioning compared to the GAV (as outlined in 14.3.10), and any capital contributions made post-commissioning compared to the appropriate NAV (as outlined in 14.3.12) as appropriate.

Modification of Connection Assets

14.3.25 Where a modification to an existing connection occurs at the User's request or due to developments to the transmission system, their annual connection charges will reflect any additional connection assets that are necessary to meet the User's requirements. Charges will continue to be levied for existing assets that remain in service. Termination charges as described in **Chapter 5** below will be charged for any existing connection assets made redundant as a result of the modification.

14.4 Other Charges

14.4.1 In addition to the basic annual connection charges set out above, the User may pay The Company for certain other costs related to their connection. These will be set out in the Bilateral and Construction Agreements where appropriate and are described below.

One-off Works

14.4.2 To provide or modify a connection, the transmission licensee may be required to carry out works on the transmission system that, although directly attributable to the connection, may not give rise to additional connection assets. These works are defined as "one-offs". Liability for one-off charges is established with reference to the principles laid out below:

- Where a cost cannot be capitalised into either a connection or infrastructure asset, typically a revenue cost
- Where a non-standard incremental cost is incurred as a result of a User's request, irrespective of whether the cost can be capitalised
- Termination Charges associated with the write-off of connection assets at the connection site.

Consistent with these principles and in accordance with Connection Charging Methodology modification GB ECM-01, which was implemented on 1 December 2005, a one-off charge will be levied for a **Category 1 Intertripping Scheme** or a **Category 3 Intertripping Scheme**. A one-off charge will **not** be levied for a **Category 2 Intertripping Scheme** or a **Category 4 Intertripping Scheme**.

14.4.3 The one-off charge is a charge equal to the cost of the works involved, together with a reasonable return, as shown in 14.4.4 below.

14.4.4 For information, the general formula for the calculation of the one-off charge for works is outlined below.

One-off Charge = (Construction Costs + Engineering Charges) x (1 + Return %)
+ IDC + LD Premium

Where: Engineering Charges = "Engineering Charge" x job hours
Return % = 6%
IDC = Interest During Construction
LD Premium = The Company Liquidated Damages Premium (if applicable)

14.4.5 The calculation of the one-off charge for write-off of assets is outlined below:

Write-off Charge = 100% of remaining NAV of redundant assets

14.4.6 One-offs are normally paid on an agreed date, which is usually upon completion of the works. However, arrangements may be agreed between the transmission licensee and the User to pay the charge over a longer period. If a one-off is paid over a longer period it is termed a Transmission Charge. It is usually a depreciating finance charge or annuity based charge with a rate of return element and may include agreement on a schedule of termination payments if the agreement is terminated before the end of the

annuity period. The charge is usually inflated annually by the same RPI figure that is used to inflate GAVs, though Users can request alternative indexation methods.

14.4.7 Where an infrastructure asset has been subject to One-off Works, and a User has paid a relating charge calculated in accordance with paragraph 14.4.4, The Company may adjust the treatment of the assets within the TNUoS transport model as set out in paragraphs 14.15.15 to 14.15.22.

Miscellaneous Charges

14.4.8 Other contract specific charges may be payable by the User, these will be set out in the Bilateral and Construction Agreements where appropriate.

Rental sites

14.4.9 Where The Company owns a site that is embedded within a distribution network, the connection charge to the User is based on the capital costs and overheads but does not include maintenance charges.

Final Metering Scheme (FMS)/Energy Metering Systems

14.4.10 Charges for FMS metering are paid by the registrant of the FMS metering at the connection site. It is charged on a similar basis as other Connection Assets. The electronic components of the FMS metering have a replacement and depreciation period in line with those advised by the transmission licensees, whilst the non-electronic components normally retain a 40 year replacement and depreciation period (or a User specified depreciation period as appropriate).

14.5 Connection Agreements

Indicative Agreement

14.5.1 The standard connection agreement offered by The Company is an indicative price agreement. From the Charging Date as set out in the User's Bilateral Connection Agreement, the User's initial connection charge is based on a fair and reasonable estimate of the expected costs of the connection.

Outturning the Indicative Agreement

14.5.2 Once the works required to provide a new or modified connection are completed and the costs finalised, the connection scheme is "outturned". The Company reconciles the monies paid by the User on the indicative charge basis against the charges that would have been payable based on the actual costs incurred in delivering the project together with any relevant interest. This process involves agreeing a new charging GAV (The Base Amount) with the User in line with the elements stated in paragraph 14.3.3 and then calculating connection charges with this GAV.

14.5.3 In addition, for Users that have chosen MEA revaluation their MEA ratios are agreed at outturn and this ratio is used for MEA revaluation in subsequent years.

14.5.4 In the case of connection asset replacement where there is no initiating User, the outturn is agreed with the User at the site.

Firm Price Agreement

14.5.5 In addition to the options stated in paragraph 14.3.10 above, firm price agreements are also available. Typically with this option the charges to be incurred, and any indexation, are agreed between The Company and the User and connection charges are not recalculated once outturn costs are known. A typical example of a firm price agreement is:

- Capital Contribution
- Firm Price GAV
- Running Costs (based on a firm price GAV)
- Fixed Schedule of Termination Amounts

14.5.6 When a User selects a firm price agreement some or all of the above elements can be made firm. Any elements of the agreement that have not been made firm will be charged on an indicative basis in accordance with this statement.

14.5.7 Final Sums and Consents costs are never made firm in a Firm Price Agreement. Details of both are set out in the Construction Agreement.

Monthly Connection Charges

14.5.8 The connection charge is an annual charge payable monthly.

14.5.9 If the initial Charging Date does not fall within the current Financial Year being charged for and there are no revisions to charges during the year, the monthly connection charge will equal the annual connection charge divided by twelve.

14.5.10 For the Financial Year in which the Charging Date occurs (as set out in the User's Bilateral Agreement) or for any Financial Year in which a revision to charges has occurred during the Financial Year, for each complete calendar month from the Charging Date (or effective date of any charge revision) to the end of the Financial Year in which the Charging Date (or charge revision) occurs, the monthly connection charge shall be equal to the annual connection charge divided by twelve.

14.5.11 For each part of a calendar month, the charge will be calculated as one twelfth of the annual connection charge prorated by the ratio of the number of days from and including the Charging Date to the end of the month that the Charging Date falls in and the number of days in that month.

14.5.12 For example, say the annual connection charge for Financial Year 2010/11 is £1.2m and the Charging Date falls on the 15th November 2010, the monthly charges for the Financial Year 2010/11 would be as follows:

• November = £1,200,000/12 * (16/30)	=	£53,333.33
• Dec 10, Jan 11, Feb 11, Mar 11	=	£1,200,000/12
	=	£100,000.00

14.5.13 The above treatment does not apply to elements such as Miscellaneous Charges (as defined in 14.4.8) and Transmission Charges (annuitised one-offs, as defined in 14.4.6). If the Charging Date falls within a Financial Year, then the full annual charge will remain payable and will be spread evenly over the remaining months. This is because these payments are an annuitisation of charges that would normally be paid up-front as one-off payments.

14.6 Termination Charges

Charges Liable

14.6.1 Where a User wholly or partially disconnects from the transmission system they will pay a termination charge. The termination charge will be calculated as follows:

- Where the connection assets are made redundant as a result of the termination or modification of a Bilateral Connection Agreement, the User will be liable to pay an amount equal to the NAV of such assets as at the end of the financial year in which termination or modification occurs, plus:

- The reasonable costs of removing such assets. These costs being inclusive of the costs of making good the condition of the connection site

- If a connection asset is terminated before the end of a Financial Year, the connection charge for the full year remains payable. Any remaining Use of System Charges (TNUoS and BSUoS) also remain payable

- For assets where it has been determined to replace upon the expiry of the relevant Replacement Period in accordance with the provisions set out in the CUSC and in respect of which a notice to Disconnect or terminate has been served in respect of the Connection Site at which the assets were located; and due to the timing of the replacement of such assets, no Connection Charges will have become payable in respect of such assets by the User by the date of termination; the termination charges will include the reasonable costs incurred by the transmission licensee in connection with the installation of such assets

- Previous capital contributions paid to The Company will be taken into account

14.6.2 The Calculation of Termination amounts for financial year n is as follows:

$$\text{Termination Charge}_n = UoS_n + C_n + NAV_{an} + R - CC$$

Where:

UoS_n = Outstanding Use of System Charge for year (TNUoS and BSUoS)
C_n = Outstanding Connection Charge for year
NAV_{an} = NAV of Type A assets as at 31 March of financial year n
R = Reasonable costs of removal of redundant assets and making good
CC = An allowance for previously paid capital contributions

14.6.3 Examples of reasonable costs of removal for terminated assets and making good the condition of the site include the following:

- If a circuit breaker is terminated as a result of a User leaving a site, this may require modifications to the protection systems.

- If an asset were terminated and its associated civils had been removed to 1m below ground then the levels would have to be made up. This is a common condition of planning consent.

Repayment on Re-Use of Assets

14.6.4 If any assets in respect of which a termination charge was made to The Company are re-used at the same site or elsewhere on the system, including use as infrastructure assets, The Company will make a payment to the original terminating User to reflect the fact that the assets are being re-used.

14.6.5 The arrangements for such repayments for re-use of Assets are that The Company will pay the User a sum equal to the lower of:

i.) the Termination Amount paid in respect of such Assets; or

ii.) the NAV attributed to such Assets for charging purposes upon their re-use

less any reasonable costs incurred in respect of the storage of those assets.

14.6.6 The definition of re-use is set out in the CUSC. Where The Company decides to dispose of a terminated asset where it is capable of re-use, The Company shall pay the User an appropriate proportion of the sale proceeds received.

Valuation of Assets that are re-used as connection assets or existing infrastructure assets re-allocated to connection

14.6.7 If an asset is reused following termination or allocated to connection when it has previously been allocated to TNUoS, a value needs to be determined for the purposes of connection charges. In both instances the connection charge will be based on the standard formula set out in paragraph 14.3.20. The Gross Asset Value will be based on the original construction costs and indexed by RPI. Where original costs are not known a reasonable value will be agreed between The Company and the User based on similar types of asset in use. The Net Asset Value will be calculated as if the asset had been in continuous service as a connection asset from its original commissioning date taking into account the depreciation period.

14.6.8 Where an asset has been refurbished or updated to bring it back into service a new value and an appropriate replacement period will be agreed between The Company and the User. This will be based on the value of similar types of asset in service and the costs of the refurbishment.

14.7 Contestability

14.7.1 Some connection activities may be undertaken by the User. The activities are the provision, or construction, of connection assets, the financing of connection assets and the ongoing maintenance of those assets. While some Users have been keen to see contestability wherever possible, contestability should not prejudice system integrity, security and safety. These concerns have shaped the terms that are offered for contestability in construction and maintenance.

Contestability in Construction

14.7.2 Users have the option to provide (construct) connection assets if they wish. Formal arrangements for Users exercising this choice are available and further information on User choice in construction can be obtained from **The Company.**

14.8 Asset Replacement

14.8.1 Appendix A of a User's Bilateral Connection Agreement specifies the age (number of complete charging years old), for charging purposes, of each of the NETS connection assets at the Connection Site for the corresponding Financial Year. Connection charges are calculated on the assumption that the assets will not need to be replaced until the charging age has reached the duration of the asset's Replacement Period.

If a connection asset is to be replaced, The Company will enter into an agreement for the replacement with the User. Where replacement occurs before the original asset's charging age has reached the duration of its Replacement Period, The Company will continue to charge for the original asset and make no charge to the existing User for the new asset until the original asset's charging age has reached the duration of its Replacement Period.

Where the replacement occurs after the original asset's charging age has reached the duration of its Replacement Period, The Company will charge on the basis of the original asset until replaced and on the basis of the new asset on completion of the works.

14.8.2 When the original asset's charging age has reached the duration of its Replacement Period the User's charge will be calculated on the then Net Asset Value of the new asset. The new asset begins depreciating for charging purposes upon completion of the asset replacement.

The Basic Annual Connection Charge Formulae are set out in **Chapter 2: The Basic Annual Connection Charge Formula.**

Asset Replacement that includes a change of Voltage

14.8.3 There are a number of situations where an asset replacement scheme may involve a change in the voltage level of a User's connection assets. These replacement schemes can take place over a number of years and may involve a long transitory period in which connection assets are operational at both voltage levels.

14.8.4 These situations are inevitably different from case to case and hence further charging principles will need to be developed over time as more experience is gained. Set out below, are some generic principles. This methodology will be updated as experience develops.

14.8.5 The general principles used to date are to ensure that, in the transitory period of an asset replacement scheme, the User does not pay for two full transmission voltage substations and that the charges levied reflect the Replacement Period of the original connection assets. In addition, in line with paragraph 14.8.1 above, charges will only be levied for the new assets once the original assets would have required replacement.

14.8.6 For example, a transmission licensee in investing to meet a future Security Standard need on the main transmission system, may require the asset replacement of an existing 275kV substation with a 400kV substation prior to the expiry of the original assets' Replacement Period. In this case, The Company will seek to recover the connection asset component via connection charges when the assets replaced were due for asset replacement. Prior to this, the User should not see an increase in charges and therefore the investment costs would be recovered through TNUoS charges.

In addition, if in the interim stage the User has, say, one transformer connected to the 275kV substation and one transformer connected to the 400kV substation, the charge will comprise an appropriate proportion of the HV assets at each site and not the full

costs of the two substations. Note that the treatment described above is only made for transitory asset replacement and not enduring configurations where a User has connection assets connected to two different voltage substations.

14.9 Data Requirements

14.9.1 Under the connection charging methodology no data is required from Users in order to calculate the connection charges payable by the User.

14.10 Applications

14.10.1 Application fees are payable in respect of applications for new connection agreements and modifications to existing agreements based on the reasonable costs transmission licensees incur in processing these applications. Users can opt to pay a fixed price application fee in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the **Statement of Use of System Charges**.

14.10.2 If a User chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees' Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Once the associated offer has been signed or lapses, a reconciliation will be undertaken. Where actual expenses exceed the advance, The Company will issue an invoice for the excess. Conversely, where The Company does not use the whole of the advance, the balance will be refunded.

14.10.3 The Company will refund the first application fee paid (the fixed fee or the amount post-reconciliation) made under the Construction Agreement for new or modified existing agreements. The refund shall be made either on commissioning or against the charges payable in the first three years of the new or modified agreement. The refund will be net of external costs.

14.10.4 The Company will not refund application fees for applications to modify a new agreement or modified existing agreement at the User's request before any charges become payable. For example, The Company will not refund an application fee to delay the provision of a new connection if this is made prior to charges becoming payable.

14.11 Illustrative Connection Charges

2010/11 First Year Connection Charges based on the RPI Method (6% rate of return)

14.11.1 The following table provides an indication of typical charges for new connection assets. Before using the table, it is important to read through the notes below as they explain the assumptions used in calculating the figures.

Calculation of Gross Asset Value (GAV)

14.11.2 The GAV figures in the following table were calculated using the following assumptions:

- Each asset is new
- The GAV includes estimated costs of construction, engineering, Interest During Construction and Liquidated Damages premiums

For details of the Calculation of the Gross Asset Value, see Chapter 2 of this Statement.

Calculation of first year connection charge

14.11.3 The first year connection charges in the following table were calculated using the following assumptions:

- The assets are new
- The assets are depreciated over 40 years
- The rate of return is assumed to be 6% for RPI indexation
- The connection charges include maintenance costs at a rate of 0.52% of the GAV
- The connection charges include Transmission Running Costs at a rate of 1.45% of the GAV

For details of the Basic Annual Connection Charge Formula, see Chapter 2 of this Statement.

Please note that the actual charges will depend on the specific assets at a site. Agreement specific NAVs and GAVs for each User will be made available on request.

Notes on Assets

The charges for Double and Single Busbar Bays include electrical and civil costs.

Transformer cable ratings are based on winter soil conditions.

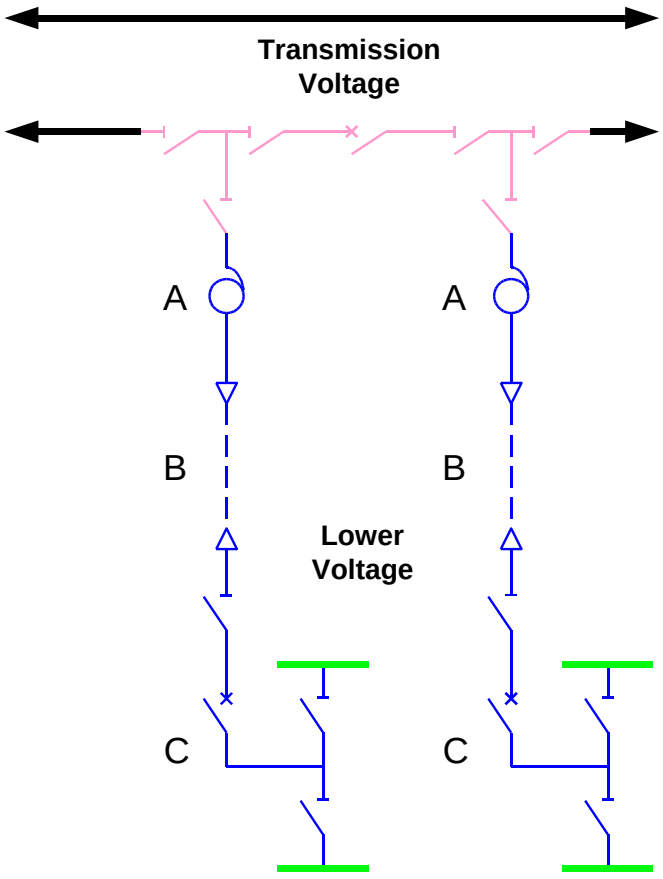
In this example, transformer charges include civil costs of plinth and noise enclosure and estimated transport costs, but not costs of oil dump tank and fire trap moat. Transport costs do not include hiring heavy load sea transportation or roll-on roll-off ships.

	£000's					
	400kV		275kV		132kV	
	GAV	Charge	GAV	Charge	GAV	Charge
Double Busbar Bay	**2300**	**239**	**1890**	**197**	**630**	**65**
Single Busbar Bay	**1830**	**190**			**460**	**50**
Transformer Cables 100m (incl. Cable sealing ends)						
120MVA			**970**	**100**	**310**	**30**
180MVA	**1480**	**150**	**970**	**101**	**320**	**30**
240MVA	**1520**	**158**	**980**	**102**	**355**	**37**
750MVA	**1540**	**160**	**1135**	**118**		
Transformers						
45MVA 132/66kV					**1060**	**110**
90MVA 132/33kV					**102 0**	**106**
120MVA 275/33kV			**2110**	**219**		
180MVA 275/66kV			**2560**	**266**		
180MVA 275/132kV			**2180**	**227**		
240MVA 275/132kV			**2630**	**273**		
240MVA 400/132kV	**3180**	**340**				

Connection Examples

Example 1

NEW SUPERGRID CONNECTION
SINGLE SWITCH MESH TYPE



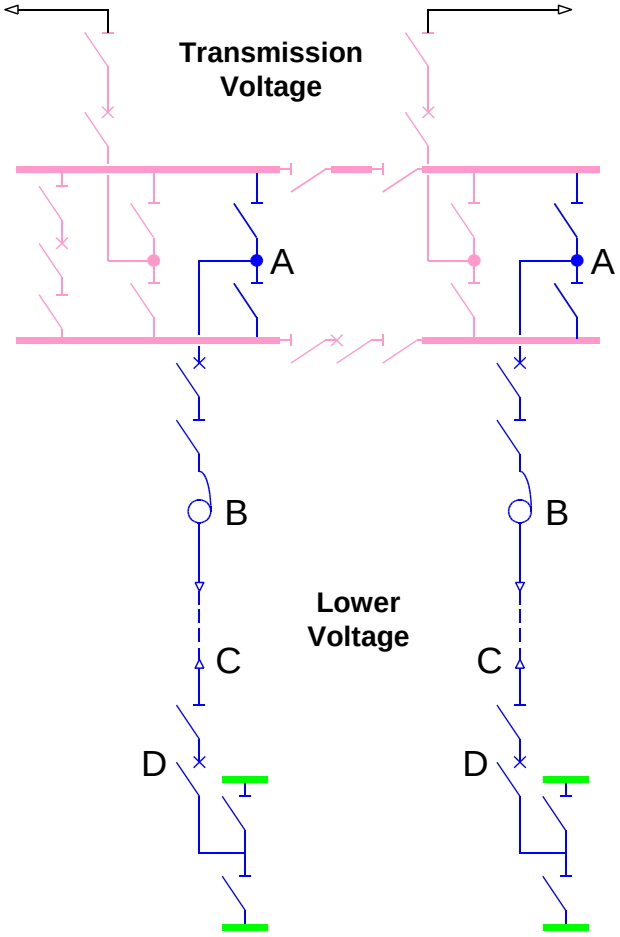
KEY:

- Existing Transmission Assets (infrastructure)
- New Transmission Assets (infrastructure)
- New connection assets wholly charged to customer
- Customer Assets

SCHEDULE FOR NEW CONNECTION				
	132/33kV		**400/132kV**	
Ref	Description	First Year Charges (£000s)	Description	First Year Charges (£000s)
A	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
B	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	72
C	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**252**	**Total**	**882**

Example 2

NEW SUPERGRID CONNECTION
DOUBLE BUSBAR TYPE



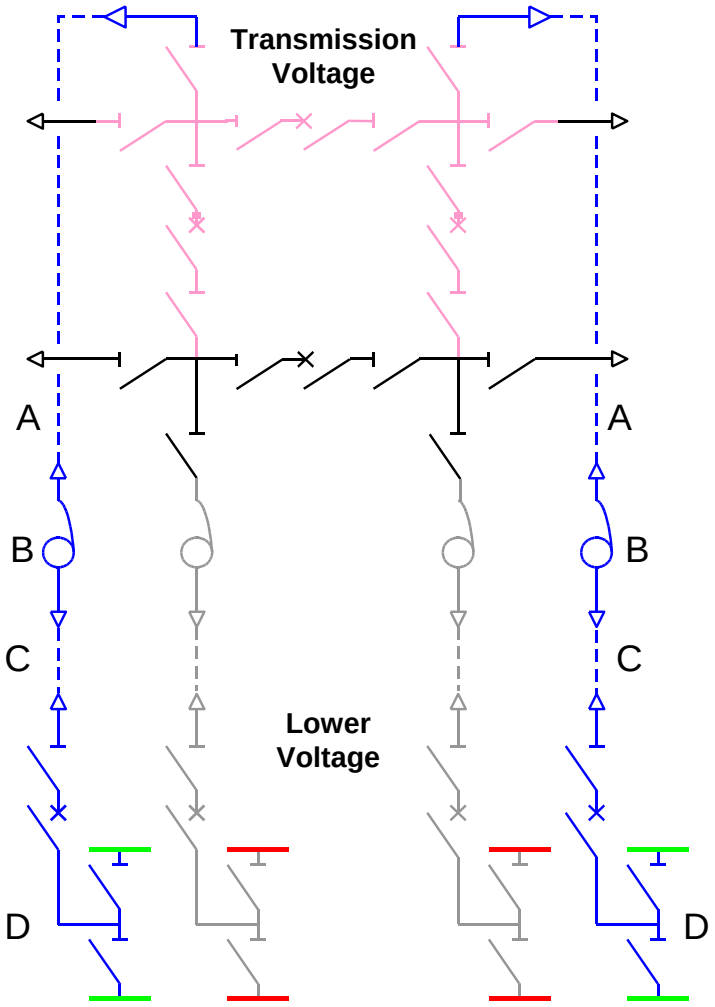
KEY:

- Existing Transmission Assets (infrastructure)
- New Transmission Assets (infrastructure)
- New connection assets wholly charged to customer
- Customer Assets

SCHEDULE FOR NEW CONNECTION				
	132/33kV		**400/132kV**	
Ref	Description	First Year Charges (£000s)	Description	First Year Charges (£000s)
A	2 x Double Busbar Transformer Bays	130	2 x Double Busbar Transformer Bays	478
B	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
C	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	74
D	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**382**	**Total**	**1362**

Example 3

EXTENSION OF SINGLE SWITCH MESH TO FOUR SWITCH MESH (extension to single user site)



KEY:

- Existing Transmission Assets (infrastructure)
- New Transmission Assets (infrastructure)
- New connection assets wholly charged to customer
- Existing connection assets wholly charged to another user
- Customer Assets
- Other Users Assets

SCHEDULE FOR NEW CONNECTION				
	132/33kV		**400/132kV**	
Ref	Description	First Year Charges (£000s)	Description	First Year Charges (£000s)
A	2 x 100m 240MVA Cables	74	2 x 100m 240MVA Cables	316
B	2 x 90MVA Transformers	212	2 x 240MVA Transformers	680
C	2 x 100m 90MVA Cables	20	2 x 100m 240MVA Cables	74
D	2 x Double Busbar Transformer Bays	20	2 x Double Busbar Transformer Bays	130
	Total	**326**	**Total**	**1200**

14.12 Examples of Connection Charge Calculations

The following examples of connection charge calculations are intended as general illustrations.

Example 1

14.12.1 This example illustrates the method of calculating the first year connection charge for a given asset value. This method of calculation is applicable to indicative price agreements for new connections, utilising the RPI method of charging, and assuming:

i) the asset is commissioned on 1 April 2010
ii) there is no inflation from year to year i.e. GAV remains constant
iii) the site specific maintenance charge component remains constant throughout the 40 years at 0.52% of GAV
iv) the Transmission Running Cost component remains constant throughout the 40 years at 1.45% of GAV
v) the asset is depreciated over 40 years
vi) the rate of return charge remains constant at 6% for the 40 year life of the asset
vii) the asset is terminated at the end of its 40 year life

For the purpose of this example, the asset on which charges are based has a Gross Asset Value of £3,000,000 on 1 April 2010.

Charge	Calculation	
Site Specific Maintenance Charge (0.52% of GAV)	3,000,000 x 0.52%	£15,600
Transmission Running Cost (1.45% of GAV)	3,000,000 x 1.45%	£43,500
Capital charge (40 year depreciation 2.5% of GAV)	3,000,000 x 2.5%	£75,000
Return on mid-year NAV (6%)	2,962,500 x 6%	£177,750
TOTAL		£311,850

The first year charge of £311,850 would reduce in subsequent years as the NAV of the asset is reduced on a straight-line basis.

This gives the following annual charges over time (assuming no inflation):

Year	Charge
1	£311,850
2	£307,350
10	£271,350
40	£136,350

Based on this example, charges of this form would be payable until 31 March 2050.

Example 2

14.12.2 The previous example assumes that the asset is commissioned on 1 April 2010. If it is assumed that the asset is commissioned on 1 July 2010, the first year charge would equal 9/12th of the first year annual connection charge i.e. £233,887.50

This gives the following annual charges over time:

Year	Charge
1	£233,887.50 (connection charge for period July to March)
2	£307,350
10	£271,350
40	£136,350

Example 3

14.12.3 In the case of a firm price agreement, there will be two elements in the connection charge, a finance component and a running cost component. These encompass the four elements set out in the examples above. Using exactly the same assumptions as those in example 1 above, the total annual connection charges will be the same as those presented. These charges will not change as a result of the adoption of a different charging methodology by The Company, providing that the connection boundary does not change.

Example 4

14.12.4 If a User has chosen a 20-year depreciation period for their Post Vesting connection assets and subsequently remains connected at the site beyond the twentieth year their charges are calculated as follows.

For years 21-40 they will pay a connection charge based on the following formula:

Annual Connection Charge$_n$ = SSF$_n$ (RPIGAV$_n$)+ TC$_n$ (GAV$_n$)

The NAV will be zero and the asset will be fully depreciated so there will be no rate of return or depreciation element to the charge.

14.13 Nominally Over Equipped Connection Sites

14.13.1 This chapter outlines examples of ways in which a connection site can be considered as having connection assets that exceed the strict, theoretical needs of the individual Users at the connection site. These can be described as:

Historical

14.13.2 This is where the connection assets at the connection site were installed to meet a requirement of the Users for connection capacity that no longer exists. An example would be where a User, at one time, had a requirement for, say, 270 MW. This would allocate three 240 MVA 400/132kV transformers to the User. Due to reconfiguration of that User's network only 200 MW is now required from the connection site. The lower requirement would only allocate two transformers, but all the transformers are kept in service. The connection assets will continue to be assigned to the User's connection, and charged for as connection, until the User makes a Modification Application to reduce the historical requirement. In some cases the Modified requirement will mean that Termination Payments will have to be made on some connection assets.

Early Construction

14.13.3 If a User has a multi-phase project, it may be necessary to install connection assets for the latter phases at the time of the first phase. These connection assets could be charged from the first phase charging date.

Connection site Specific Technical or Economic Conditions

14.13.4 In circumstances where the transmission licensee has identified a wider requirement for development of the transmission system, it may elect to install connection assets of greater size and capacity than the practicable minimum scheme required for a particular connection. In these circumstances, however, connection charges for the party seeking connection will normally be based on the level of connection assets consistent with the practicable minimum scheme needed to meet the applicant's requirements.

14.13.5 There may be cases where there are specific conditions such that the practicable minimum scheme at a site has to be greater than the strict, theoretical interpretation of the standards. In these cases all assets will still be assigned to connection and connection charges levied.

14.13.6 A practicable minimum scheme is considered in terms of the system as a whole and may include a change in voltage level.

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

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

14.14 Principles

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

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

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

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

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

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

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

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

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

v.) The application of a Transmission Network Use of System Revenue split between generation and demand where the proportion of the total revenue paid by generation, for the purposes of tariff setting for a charging year n, is x times the total revenue, where x is:

1. Whilst European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit on annual average transmission charge payable by generation) is in effect (a "Limiting Regulation") then:

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

Where;

Cap_{EC}	=	Upper limit of the range specified a Limiting Regulation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-1

2. Where there is no Limiting Regulation, then x for charging year n is set as the value of x used in the last charging year for which there was a Limiting Regulation.

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

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

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

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

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

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

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

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

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

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

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

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

14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

The Transport Model

Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These

conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

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

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

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

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

Adjustments to Model Inputs associated with One-off Works

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a One-Off Charge) that related to works equivalent to those described under

paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

Ref	Description of works	Adjustments
1	Undergrounding - A User requests to underground an overhead line at a greater cost.	As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL.
2	Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO.	As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model.
3	Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO.	As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model.

Ref	Description of works	Adjustments
4	Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage.	As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage.

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

Ref	Description of works	Reasoning
1	Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried.	Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost.
2	Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route.	Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost.
3	Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs.	Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost.
4	Additional substation works - A User asks for screening to be provided around a new or existing substation.	The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model.
5	Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc.	The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model.
6	Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO.	The temporary circuit changes will not be incorporated into the transport model.

7	Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity.	No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged).
8	Early asset replacement - An asset is replaced prior to the end of its expected life.	As the asset is simply replaced, no data in the transport model is expected to change.
9	Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs.	The data in the transport model is unaffected.
10	Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18.	The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation.
11	Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18.	As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value.

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

Model Outputs

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total net GB demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

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

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

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

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

Where

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

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

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

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

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

Where

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

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

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

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

Where:

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

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

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

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

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

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

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

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

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

Accounting for Sharing of Transmission by Generators

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

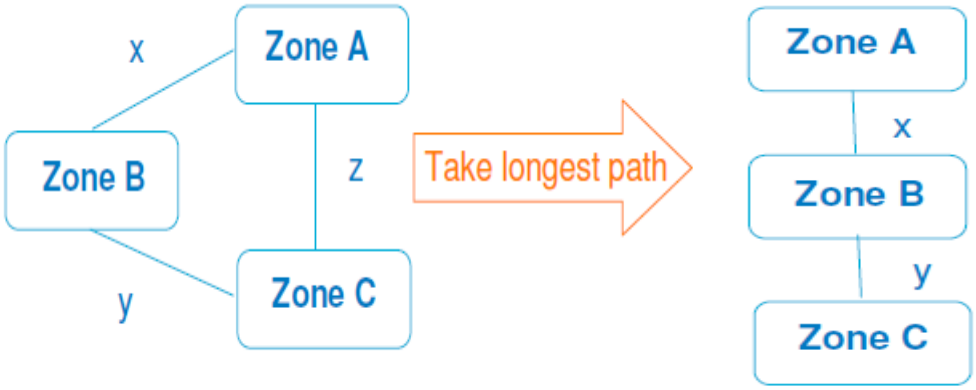
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by The Company in the Statement of Use of System Charges as new generation technologies are developed.

Carbon	**Low Carbon**
Coal	Wind
Gas	Hydro (excl. Pumped Storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

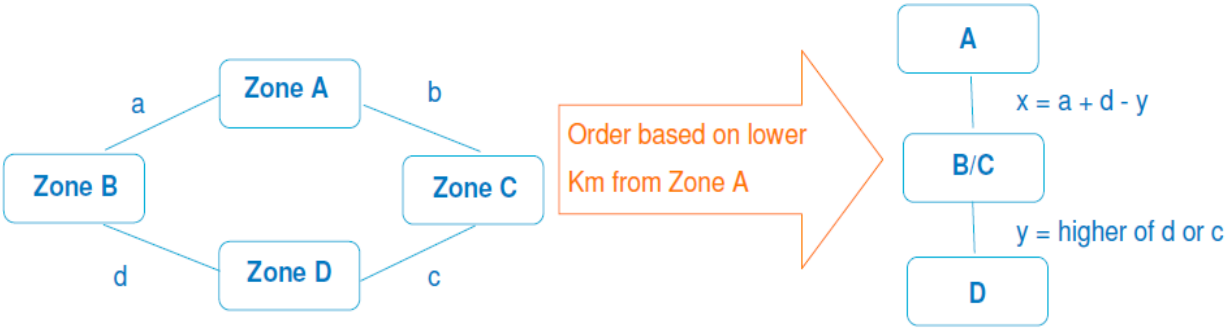
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

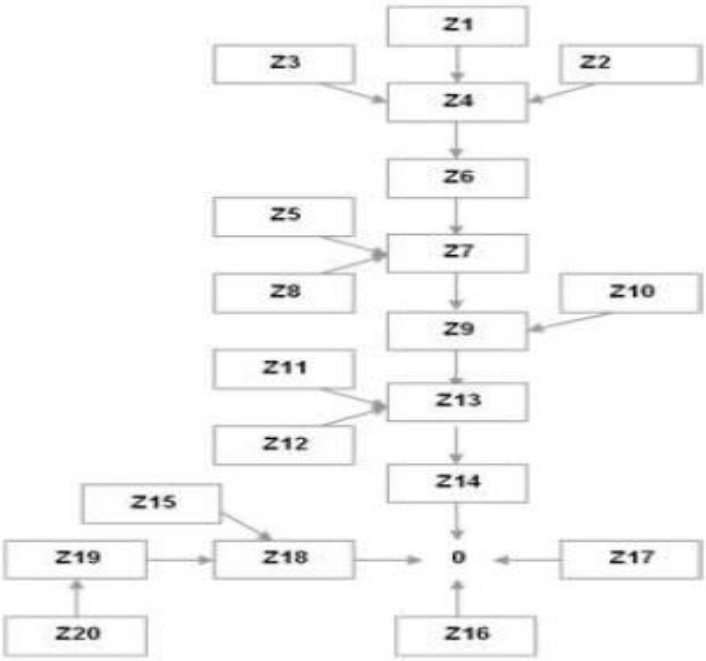
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.



- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.



14.15.51 An illustrative Connectivity diagram is shown below:



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

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

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

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

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

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

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \; x \; BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
BSF_{ab} = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

400kV OHL expansion constant calculation					
MW	**Type**	**£(000)/k**	**Circuit km***	**£/MWkm**	**Weight**
A	B	C	D	E = C/A	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750
5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
Sum			**2500 (G)**		**285400 (H)**
				Weighted Average (J= H/G):	**114.160 (J)**

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is NGET's regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

400kV OHL expansion constant calculation	Ave £/MWkm
OHL	114.160

Annuitised	7.535
Overhead	2.055
Final	**9.589**

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in the Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

Onshore Wider Circuit Expansion Factors

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of NGET and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Onshore Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

400kV underground cable factor:	22.39
275kV underground cable factor:	22.39
132kV underground cable factor:	27.79
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.24

Scottish Power & NGET Regions

400kV underground cable factor:	22.39
275kV underground cable factor:	22.39
132kV underground cable factor:	30.22
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor:	2.80

Onshore Local Circuit Expansion Factors

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

400kV underground cable factor:	22.39
275kV underground cable factor:	22.39
132kV underground cable factor:	30.22
400kV line factor:	1.00
275kV line factor:	1.14
132kV line factor (single; <200MVA):	10.00
132kV line factor (double; <200MVA):	8.32
132kV line factor (single; >=200MVA):	7.13
132kV line factor (double; >=200MVA):	4.42

Offshore Circuit Expansion Factors

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

CRevOFTO1	=	The offshore circuit revenue in £ for Year 1
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

AvCRevOFTO	=	The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control
L	=	The total circuit length in km of the offshore circuit
CircRat	=	The continuous rating of the offshore circuit

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\,\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

$OFTOInd_{t,f}$	=	the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*;
$OFTORevInd_{t,f}$	=	the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its transmission licence in respect of charging year *t*; and
RPI_t	=	the indexation rate applied to the expansion constant in respect of charging year *t*.

Offshore Interlinks

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:

$$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$$

For Substation B:

$$\min \{ ILF_B \times TEC_B - RCap_B, \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$$

For Substation C:

$$\min \{ Cap_{IBC}, ILF_C \times TEC_C - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$$

and

Cap_{IAB} = total capacity of the Offshore Interlink between substations A and B

Cap_{IBC} = total capacity of the Offshore Interlink between substations B and C

Cap_X = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

TEC_X = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

ILF_X = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

The Locational Onshore Security Factor

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

Local Security Factors

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; D_{min} = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

T_{cap} = transmission capacity built (MVA)

G_{cap} = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_{k} Gen_{k}}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\text{IRevOFTO} \times \text{NetworkExportCapacity}}{\text{CRevOFTO} \times \sum_{k} \text{Gen}_{k}} + LocalSF_{\text{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

Initial Transport Tariff

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$

$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$

$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

ITT_{GiPS} = Peak Security Initial Transport Tariff (£/MW) for each generation zone

ITT_{GiYRNS} = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

ITT_{GiYRS} = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ($ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$	=	Peak Security Zonal Marginal km for each demand zone
$ZMkm_{DiYR}$	=	Year Round Zonal Marginal km for each demand zone
ITT_{DiPS}	=	Peak Security Initial Transport Tariff (£/MW) for each demand one
ITT_{DiYR}	=	Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups.

a.

Where

$ITRR_G$	=	Initial Transport Revenue Recovery for generation
G_{Gi}	=	Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)
$ITRR_D$	=	Initial Transport Revenue Recovery for gross GSP group demand
D_{Di}	=	Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. When calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below). When calculating the initial revenue recovery for the Not Shared component of the Year Round background, the initial tariffs are multiplied by the **Year Round Not Shared Flag**.

Peak Security (PS) Flag

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

Generation Plant Type	PS flag
Intermittent	0
Other	1

Year Round Not Shared (YRNS) Flag

14.15.100 The revenue from a specific generator due to the Year Round Not Shared locational tariff needs to be multiplied by the appropriate Year Round Not Shared (YRNS) flag. The YRNS flag indicates the extent to which a generation plant type contributes to the need for transmission network investment at year round demand conditions in areas of the System where the proportion of Low Carbon generation exceeds Carbon generation as defined in 14.15.49.

Generation Plant Type	YRNS flag
Non Conventional Carbon	1
Conventional Carbon	ALF

Annual Load Factor (ALF)

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

14.15.102 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
TEC_p is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.103 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to The Company and relates to the total TEC of the Power Station.

14.15.104 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.105 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.106 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.107 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.108 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.109 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

Derivation of Generic ALFs

14.15.110 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

Fuel Type
Biomass
Coal
Gas
Hydro
Nuclear (by reactor type)
Oil & OCGTs
Pumped Storage
Onshore Wind
Offshore Wind
CHP

14.15.111 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.112 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.113 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

TNUoS Embedded Export Tariff

14.15.114 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

ITT_{DiPS} = Peak Security Initial Transport Tariff for the demand zone;
ITT_{DiYR} = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{1}{3}(XP - AGIC) + AGIC$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= AGIC$$

Where
XP = Value of demand residual in charging year prior to implementation
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of EET_{Di} will be floored at zero, so that EET_{Di} is always zero or positive.

Initial Revenue Recovery

14.15.116 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

G_{Gi} = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

F_{PS} = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

D_{Di} = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.117 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for the Not-Shared component from Non Conventional Carbon. For Conventional Carbon the initial tariff for the Not Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery. The initial tariff for the Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSNCC} \times G_{Gi}\right) = ITRR_{GYRNSNCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSCC} \times G_{Gi} \times ALF\right) = ITRR_{GYRNSCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

$$ITRR_{GYRNS} = ITRR_{GYRNSNCC} + ITRR_{GYRNSCC}$$

Where:

$ITRR_{GYRNSNCC}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for Non Conventional Carbon generation
$ITRR_{GYRNSCC}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for Conventional Carbon generation
$ITRR_{GYRNS}$	=	Year Round Not-Shared Initial Transport Revenue Recovery for generation
$ITRR_{GYRS}$	=	Year Round Shared Initial Transport Revenue Recovery for generation
ALF	=	Annual Load Factor appropriate to that generator.

14.15.118 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$	=	Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.119 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITRR_{EE}$	=	Initial Revenue impact for Embedded Exports
EEV_{Di}	=	Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for embedded exports can be positive or negative.

Deriving the Final Local Tariff (£/kW)

Local Circuit Tariff

14.15.120 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the

relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

k	=	Local circuit *k* for generator
$NLMkm_{Gj}^{L}$	=	Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor.
EC	=	Expansion Constant
$LocalSF_k$	=	Local Security Factor for circuit *k*
CLT_{Gi}	=	Circuit Local Tariff (£/kW)

Onshore Local Substation Tariff

14.15.121 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.122 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

Substation Rating (b)	**Connection Type** (c)	**Substation Voltage** (a)		
		132kV	**275kV**	**400kV**
<1320MW	No redundancy	0.133	0.081	0.065
<1320MW	Redundancy	0.301	0.192	0.155
>=1320MW	No redundancy	n/a	0.257	0.208
>=1320MW	Redundancy	n/a	0.417	0.336

14.15.123 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

14.15.124 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

ELT_{Gi} = Effective Local Tariff (£/kW)
SLT_{Gi} = Substation Local Tariff (£/kW)

14.15.125 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

$ELT_{Gi} = LT_{Gi}$

Where

LT_{Gi} = Final Local Tariff (£/kW)

14.15.126 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left(ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.127 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR_G} = \sum_{j=Gi} \mathrm{LT_{Gi}} * G_j$$

Where

$LCRR_G$ = Local Charge Revenue Recovery

G_j = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

Offshore substation local tariff

14.15.128 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.129 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.130 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.131 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.132 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.133 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left(SLT_k \times \sum_k Gen_k \right)$$

Where:

SLT_k	=	the offshore substation tariff for substation k
Gen_k	=	the generation connected to offshore substation k

The Residual Tariff

14.15.134 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges (TRR_t) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

TRR_t	=	TNUoS Revenue Recovery target for year t
R_t	=	Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.
PVC_t	=	Forecast Revenue from Pre-Vesting connection charges for year t
SG_{t-1}	=	The proportion of the under/over recovery included within R_t which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.135 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.136 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is

calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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

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

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

Final £/kW Tariff

14.15.137 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

and

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

ET_{Gi}= Effective Generation TNUoS Tariff expressed in £/kW (ET_{Gi} would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT_{GiPS}, ITT_{GiYRNS} and ITT_{GiYRS} will be applied using Power Station specific data)

ET_{Di}= Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

ET_{EEi}= Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges ET_{Gi} will be published as ITT_{GiPS}; ITT_{GiYRNS}, $ITT_{GiYRS,}$ RT_G and LT_{Gi}

14.15.138 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

14.15.139 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left(ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{Di} = \frac{12 \times \left(ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}} \quad \text{and} \quad FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The ET_{Gi} element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station G_{Gi}, aggregated to ensure overall correct revenue recovery.

14.15.140 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} \left(FT_{Di} \times D_{Di} \right)}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

RFT_{Di} = Revised Final Tariff (£/kW)

14.15.141 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.142 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.143 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.144 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

14.15.145 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

14.15.146 The factors which will affect the level of TNUoS charges from year to year include-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the Year Round Not Shared (YRNS) Flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- Changes in the pattern of embedded exports

14.15.147 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution

network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

Stability & Predictability of TNUoS tariffs

14.15.148 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

£/kW Tariff = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

$NHHD_F$ = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

FL_G = Forecast Liability incurred for the GSP Group concerned.

$NHHC_G$ = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff (ET_{Gi}) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

FT	=	Final annual TNUoS Tariff expressed in £/kW
Gi	=	Generation zone
STTEC Period	=	A period applied for in days as defined in the CUSC

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where FT is the final annual TNUoS tariff expressed in £/kW;
G_i is the generation TNUoS zone; and
P is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

14.17 Demand Charges

Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

Basis of Gross Demand Charges

14.17.3 Gross Demand charges are based on a de minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges.

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = Chargeable\ Gross\ Demand\ Capacity \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

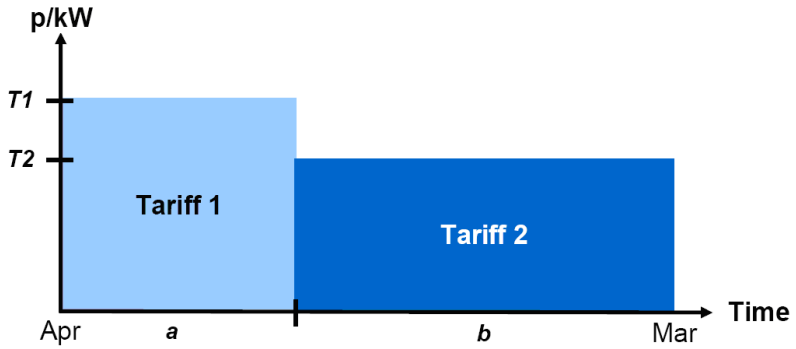
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.



14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

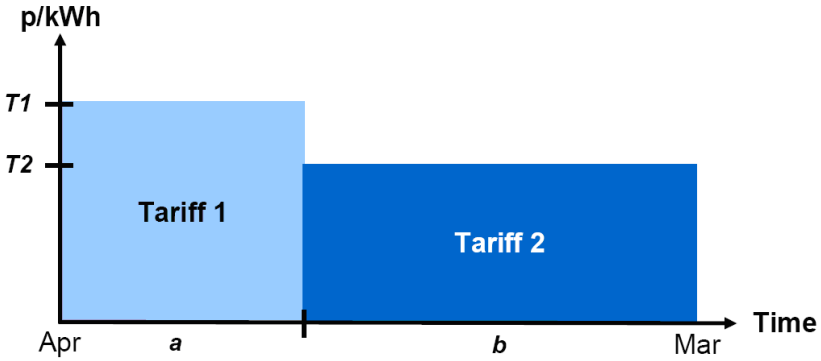
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.



Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \begin{matrix}Chargeable\ Embedded \\ Export\ Capacity\end{matrix} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

Supplier BM Unit

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff), *and*
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement

14.17.14 The Chargeable Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the net import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be

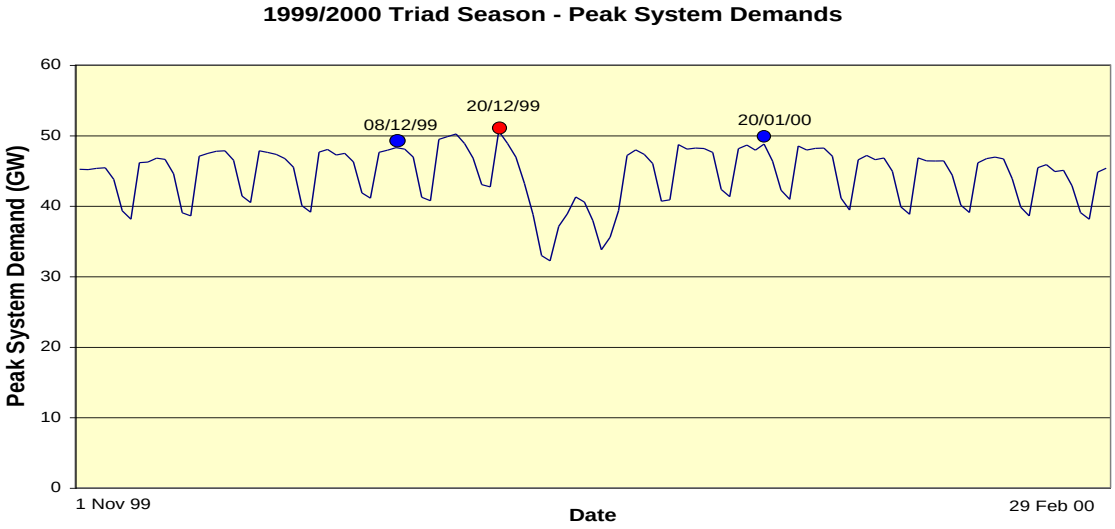
based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak netdemand. An illustration is shown below.



Half-hourly metered demand charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and
- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable demand forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year.

Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

Initial Reconciliation Part 2 – Non-half-hourly metered demand

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

Final Reconciliation of demand charges

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

Reconciliation of manifest errors

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the

reconciliation process for all Users qualifying under Section 14.17.3333 will be in accordance with Sections 14.17.244 to 14.17.3030. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or
b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

Implementation of P272

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies

14.17.35.3 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position

14.17.35.4 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the

purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.5 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/ Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.6 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

HH Elective Metering from 1st April 2017. The following section describes how meters migrating to, or already within, Measurement Classes E,F and G will be charged in terms of TNUoS after 31st March 2017.

14.17.29.8 A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation for Non-Half Hourly (NHH) meters migrating to Measurement Classes E, F & G for the charging year which begins after 31 March 2017.

14.17.29.9 Notwithstanding 14.17.9, for each Charging Year which begins after 31 March 2017 demand associated with Measurement Classes F and G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year up until the Charging Year which begins after 31st March 2020. Demand associated with Measurement Class E will continue to be treated as Chargeable Demand Capacity (HH).

14.17.29.10 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from ELEXON i.e. Suppliers need not Supply any additional information.

14.17.29.11 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.16 and 14.17.17 for both Chargeable Demand Capacity and

Chargeable Energy Capacity should reflect the basis on which demand will be charged for TNUoS i.e. volumes associated with those Metering Systems that have transferred to Measurement Class F & G in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity.

Further Information

14.17.35 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded consumption and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.36 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.37 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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.

14.18.2 14.26 Classification of parties for charging purposes provides an illustration of how a party is classified in the context of Use of System charging and refers to the relevant paragraphs most pertinent to each party.

Structure of Generation Charges

14.18.3 Generation Tariffs are comprised of Wider and Local Tariffs. The Wider Tariff is comprised of (i) a Peak Security element, (ii) a Year Round Not-Shared element, (iii) Year Round Shared element and (iv) a residual element. The Peak Security element of the Wider Tariff is not applicable for intermittent generators as the PS flag is set to zero. The Year Round Not Shared element is multiplied by the YRNS Flag, which for Non-Conventional Carbon Generators results in no change to the tariff, whereas for Conventional Carbon generators the tariff is reduced by ALF

14.18.4 The Local Tariff contains a substation element and may also contain a circuit element. Specifically, all transmission connected generation will be liable to pay a local substation charge, with some of these also being liable to pay a local circuit charge. For the avoidance of doubt, embedded generation has a zero local tariff.

14.18.5 The intention of the charging rules is to charge the same physical entity only once.

14.18.6 The basis of the generation charge for Power Stations is the Chargeable Capacity and the short-term chargeable capacity (as defined below for positive and negative charging zones).

14.18.7 If there is a single set of Wider and Local generation tariffs within a charging year, the Chargeable Capacity is multiplied by the relevant generation tariff to calculate the annual liability of a generator.

$$Local\ Annual\ Liability = Chargeable\ Capacity \times Local\ Tariff$$

The Wider Tariff is broken down into four components as described in 14.18.3. The breakdown of the Wider Charge for Conventional and Intermittent Power Stations are given below:

Conventional Low Carbon-

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (PS\ Tariff + YRNS\ Tariff + (YRS\ Tariff \times ALF) + Residual Tariff)$$

Conventional Carbon

$$Wider\ Annual\ Liabiity\ Chargeable\ Capacity\ x\ (PS\ Tariff + (YRNS\ Tariff\ \times ALF) + (YRS\ Tariff\ \times\ ALF) + Residual\ Tariff)$$

Intermittent -

$$Wider\ Annual\ Liability = Ch\arg eable\ Capacity \times \left(YRNS\ Tariff + \left(YRS\ Tariff \times ALF\right) + \mathrm{Re}\, sidualTariff \right)$$

Where:
PS Tariff = Wider Peak Security Tariff
YRNS Tariff = Wider Year Round Not-Shared Tariff
YRS Tariff = Wider Year Round Shared Tariff

14.18.8 If multiple sets of Wider and Local generation tariffs are applicable within a single charging year, the Chargeable Capacity is multiplied by the relevant tariffs pro rated over the entire charging year, across the months that they are applicable for.

$$Annual\ Liability = Chargeable\ Capacity \times \left(\frac{a \times Tariff\ 1 + b \times Tariff\ 2}{12} \right)$$

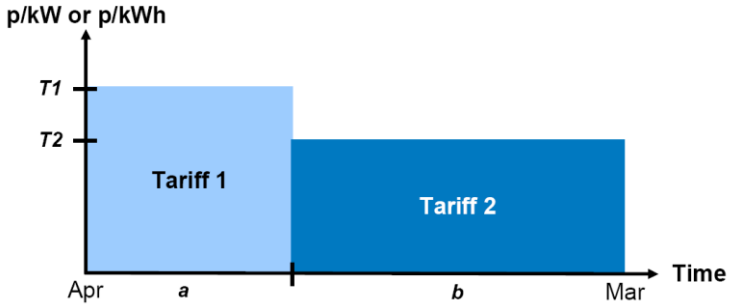
where:

Liability 1 = Original annual liability,

Liability 2 = Revised annual liability,

a = Number of months over which the original liability is applicable,

b = Number of months over which the revised liability is applicable.



14.18.9 For the avoidance of doubt if there are multiple sets of Wider and Local generation tariffs applicable within a single charging year and a tariff changes from being positive to negative or vice versa, the Chargeable Capacity for the entire charging year will be determined based on the net position of the pro rated tariffs for each affected generator.

Basis of Wider Generation Charges

Generation with positive wider tariffs

14.18.10 The Chargeable Capacity for Power Stations with positive wider generation tariffs is the highest Transmission Entry Capacity (TEC) applicable to that Power Station for that Financial Year. A Power Station should not exceed its

TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity, STTEC). For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

14.18.11 The short-term chargeable capacity for Power Stations situated with positive generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as appropriate.

14.18.12 For Power Stations, the short term chargeable capacity for LDTEC with positive generation tariffs referred to in Paragraph 14.18.11will be the capacity purchased either on a profiled firm[2] or indicative[3] basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second of 50MW. Further examples are provided in 14.16.6.

Generation with negative wider tariffs

14.18.13 The Chargeable Capacity for Power Stations with negative wider generation tariffs is the average of the capped metered volumes during the three settlement periods described in 14.18.14 below, for the Power Station (i.e. the sum of the metered volume of each BM Unit associated with Power Station in Appendix C of its Bilateral Agreement). A Power Station should not exceed its TEC as to do so would be in breach of the CUSC, except where it is entitled to do so under the specific circumstances laid out in the CUSC (e.g. where a User has been granted Short Term Transmission Entry Capacity). If TEC is exceeded, the metered volumes would each be capped by the TEC for the Power Station applicable for that Financial Year. For the avoidance of doubt, TNUoS Charges will be determined on the TEC held by a User as specified within a relevant bilateral agreement regardless of whether or not it enters into a temporary TEC Exchange (as defined in the CUSC).

14.18.14 The three settlement periods are those of the highest metered volumes for the Power Station and the two half hour settlement periods of the next highest metered volumes which are separated from the highest metered volumes and each other by at least 10 Clear Days, between November and February of the relevant Financial Year inclusive. These settlement periods do not have to coincide with the Triad.

Example

If the highest TEC for a Power Station were **250MW** and the highest metered volumes and resulting capped metered volumes were as follows:

[2] where an LDTEC Block Offer has been accepted (Profiled Block LDTEC) and a firm profile of capacity has been purchased.

[3] where an LDTEC Indicative Block Offer has been accepted (Indicative Profiled Block LDTEC) and a right to future additional capacity up to a requested level has been purchased, the availability of which will be notified on a weekly basis in accordance with the CUSC.

Date	19/11/08	13/12/08	06/02/09
Highest Metered Volume in month (MW)	**245.5**	**250.3**	**251.4**
Capped Metered Volume (MW)	**245.5**	**250.0**	**250.0**

Then, the chargeable Capacity for the Power Station would be:

$$\left(\frac{245.5+250+250}{3}\right) = \textbf{248.5 MW}$$

Note that in the example above, the Generator has exceeded its TEC on 13 December 2007 and 6 February 2008 and would therefore be in breach of the CUSC unless the generator had an approved STTEC or LDTEC value. (The STTEC and LDTEC charge for negative zones is currently set at zero).

14.18.15 The short-term chargeable capacity for Power Stations with negative generation tariffs is any approved STTEC or LDTEC applicable to that Power Station during a valid STTEC Period or LDTEC Period, as applicable.

14.18.16 For Power Stations with negative generation tariffs, the short-term chargeable capacity for LDTEC referred to in Paragraph 14.18.15 will be the capacity purchased either on a profiled firm or indicative basis and shall be assessed according to the capacity purchased on a weekly basis. The short-term chargeable capacity for LDTEC in any week may comprise of a number of increments, which shall be determined by considering LDTEC purchased previously in the Financial Year (whether or not in the same LDTEC Period). For example, if in a given week the LDTEC is 200MW but in a previous week the LDTEC had been 150MW, the short-term chargeable capacity in the latter week would comprise of two increments: one of 150MW and a second at 50MW.

14.18.17 As noted above, a negative LDTEC tariff in negative generation charging zones is set to zero. Accordingly no payments will be made for use of LDTEC (in any of its forms) in these zones.

Basis of Local Generation Charges

14.18.18 The Chargeable Capacity for Power Stations will be the same as that used for wider generation charges, except that each component of the local tariff shall be considered separately as to whether it is a positive or negative tariff component. This means that where a local circuit tariff is negative, the final charging liability for this element will be based on actual metered output as described in Paragraph 14.18.12.

Small Generators Charges

14.18.19 Eligible small generators' tariffs are subject to a discount of a designated sum defined by Licence Condition C13 as 25% of the combined residual charge for generation and demand. The calculation for small generators charges is not part of the methodology however, for information the designated sum is included in **The Statement of Use of System Charges.**

Monthly Charges

14.18.20 Initial Transmission Network Use of System Generation Charges for each Financial Year will be based on the Power Station Transmission Entry Capacity (TEC) for each User as set out in their Bilateral Agreement. The charge is calculated as above. This annual TNUoS generation charge is split evenly over the months remaining in the year. For positive final generation tariffs, if TEC increases during the charging year, the party will be liable for the additional charge incurred for the **full** year, which will be recovered uniformly across the remaining chargeable months in the relevant charging year (subject to Paragraph 14.18.21 below). An increase in monthly charges reflecting an increase in TEC during the charging year will result in interest being charged on the differential sum of the increased and previous TEC charge. The months liable for interest will be those preceding the TEC increase from April in year t. For negative final generation tariff, any increase in TEC during the year will lead to a recalculation of the monthly charges for the remaining chargeable months of the relevant charging year. However, as TEC decreases do not become effective until the start of the financial year following approval, no recalculation is necessary in these cases. As a result, if TEC increases, monthly payments to the generator will increase accordingly.

14.18.21 The provisions described above for increases in TEC during the charging year shall not apply where the LDTEC (in any of its forms) has been approved for use before the TEC is available, which will typically mean the LDTEC has been approved after the TEC increase has been approved. In such instances, the party shall commence payments for TEC during the LDTEC Period for LDTEC purchased up to the future level of TEC and LDTEC Charges will only apply to LDTEC that is incremental to the TEC increase. For the avoidance of doubt, where TEC has been approved after LDTEC in a given year, these provisions shall not apply and the LDTEC shall be considered additional to the TEC and charged accordingly.

Ad hoc Charges

14.18.22 For each STTEC period successfully applied for, a charge will be calculated by multiplying the STTEC by the tariff calculated in accordance with Paragraph 14.16.3. The Company will invoice Users for the STTEC charge once the application for STTEC is approved.

14.18.23 For Power Stations utilising LDTEC (in any of its forms) the LDTEC Charge for each LDTEC Period is the sum of the charging liabilities associated with each incremental level of short term chargeable capacity provided by LDTEC within the LDTEC Period (assessed on a weekly basis). The charging liability for a given incremental level of short term chargeable capacity is the sum of:

i) the product of the higher tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment for the first 17 weeks in a Financial Year (whether consecutive or not); and

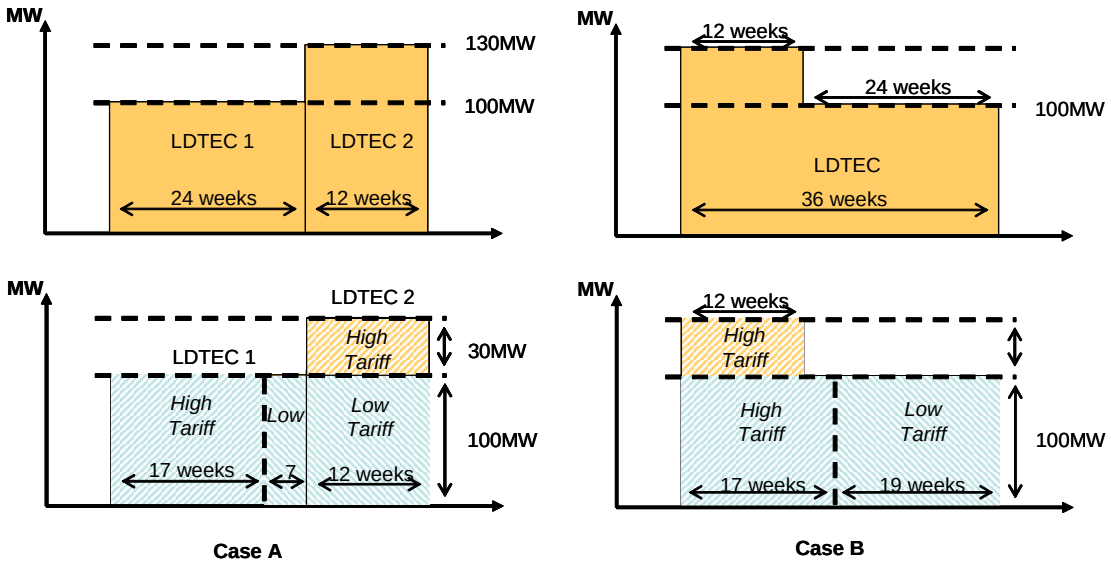
ii) the product of the lower tariff rate (calculated in accordance with Paragraph 14.16.6) and capacity purchased at this increment in any additional weeks within the same Financial Year (whether consecutive or not).

14.18.24 For each LDTEC Period successfully applied for, the LDTEC Charge will be split evenly over the relevant LDTEC Period and charged on a monthly basis. LDTEC charges will apply to both LDTEC (in any of its forms) and Temporary Received TEC held by a User. For the avoidance of doubt, the charging

methodology will not differentiate between access rights provided to a generator by LDTEC or through Temporary Received TEC obtained through a Temporary TEC Exchange (as defined in the CUSC).

Example

The diagrams below show two cases where LDTEC has been purchased: in Case A, two LDTEC Periods have been purchased; and in Case B one LDTEC Period has been purchased. The total capacity purchased in both cases is the same. The top diagrams illustrate the capacity purchased, while lower diagrams illustrate the incremental levels of short term chargeable capacities of LDTEC and the tariff rate that would apply to that capacity.



In both cases, the total amount charged for the LDTEC would be the same:

- ❑ Capacity charges at the higher tariff rate:
  - 17 weeks at the 100MW increment
  - 12 weeks at the 30MW increment
- ❑ Capacity charges at the lower tariff rate:
  - 19 weeks at the 100MW increment
- ❑

Embedded Transmission Use of System Charges "ETUoS"

14.18.25 The ETUoS charges are a component of Use of System charges levied on offshore generators whose offshore transmission connection is embedded in an onshore distribution network. The charge relates to the provision and use of the onshore distribution network.

14.18.26 The main purpose of ETUoS charges is to pass through the charges that are levied by the DNO on the NETSO to the offshore generator(s). This charge reflects the charges levied by the DNO for the costs of any works on and use of the DNO network in accordance with the DNO's charging statements and will include, but is not limited to, upfront charges and capital contributions in respect of any works as well as the ongoing and annual Use of System charges for generation connected to the distribution network.

14.18.27 In the case of some relevant transitional offshore generation projects, ETUoS will also be used to pass through historic DNO capital contributions forming part of the Offshore Transmission Owner tender revenue stream.

14.18.28 The specific nature of the ETUoS charge and the payment profile for these will depend upon the charging arrangements of the relevant DNO and reference should be made to the relevant DNO's charging statement. In terms of applicable transitional offshore generation projects the ETUoS payment profile will be consistent with the recovery of the Offshore Transmission Owner revenue stream.

14.18.29 Where a DNO's charge relates to more than one offshore generator, the related ETUoS charge will represent a straight pass through of the distribution charge specific to each relevant offshore generator. Where specific information is not available, charges will be pro-rated based on the TEC of the relevant offshore generators connected to that offshore network.

14.18.30 Invoices for ETUoS charges shall be levied by The Company on the offshore generator as soon as reasonably practicable after invoices have been received by The Company for payment such that The Company can meet its payment obligations to the DNO. The initial payments and payment dates will be outlined in a User's Construction Agreement and/or Bilateral Agreement.

14.18.31 As the ETUoS charges reflect the DNO charges to The Company, such charges will be subject to variation when varied by the DNO. Where the User disputes regarding the ETUoS charge please note that this will result in a dispute between The Company and DNO under the DCUSA.

Reconciliation of Generation Charges

14.18.32 The reconciliation process is set out in the CUSC and in line with the principles set out above.

14.18.33 In the event of a manifest error in the calculation of TNUoS charges which results in a material discrepancy in a User's TNUoS charge as defined in Sections 14.17.32 to 14.17.34, the generation charges of Users qualifying under Section 14.17.33 will be reconciled in line with 14.18.20 and 14.18.25 using the recalculated tariffs.

Further Information

14.18.34 **The Statement of Use of System Charges** contains the £/kW generation zonal tariffs for the current Financial Year.

14.19 Data Requirements

Data Required for Charge Setting

14.19.1 Users who are Generators or Interconnector Asset Owners provide to The Company a forecast for the following Financial Year of the highest Transmission Entry Capacity (TEC) applicable to each Power Station or Interconnector for that Financial Year. For Financial Year 2008/9 Scottish Generators or Interconnector Asset Owners provide to The Company a forecast of the equivalent highest 'export' capacity figure. This data is required by The Company as the basis for setting TNUoS tariffs. The Company may request these forecasts in the November prior to the Financial Year to which they relate, in accordance with the CUSC. Additionally users who are Generators provide to The Company details of their generation plant type.

14.19.2 Users who are owners or operators of a User System (e.g. Distribution companies) provide a forecast for the following Financial Year of the Natural Demand attributable to each Grid Supply Point equal to the forecasts of Natural Demand under both Annual Average Cold Spell (ACS) Conditions and a forecast of the average metered Demand attributable to such Grid Supply Point for the National Grid Triad. This data is published in table 2.4 of the Seven Year Statement and is compiled from week 24 data submitted in accordance with the Grid Code.

14.19.3 For the following Financial Year, The Company shall use these forecasts as the basis of Transmission Network Use of System charges for such Financial Year. A description of how this data is incorporated is included in 14.15 Derivation of the Transmission Network Use of System Tariff.

14.19.4 If no data is received from the User, then The Company will use the best information available for the purposes of calculation of the TNUoS tariffs. This will normally be the forecasts provided for the previous Financial Year.

Data Required for Calculating Users' Charges

14.19.5 In order for The Company to calculate Users' TNUoS charges, Users who are Suppliers shall provide to The Company forecasts of half-hourly and non-half-hourly demand in accordance with paragraph 14.17.14 and 14.17.15 and in accordance with the CUSC.

14.20 Applications

14.20.1 Application fees are payable in respect of applications for new Use of System agreements; modifications to existing agreements; and applications for short-term access products or services. These are based on the reasonable costs that transmission licensees incur in processing these applications.

Applications for short-term access

14.20.2 Application fees for short-term access products or services are fixed and detailed in the **Statement of Use of System Charges**. These are non-refundable except for the following limited instances:

- Where a User (or Users) withdraw their application in accordance with any interactivity provisions that may be contained within the CUSC; or

- Where the application fee covers ongoing assessment work that is contingent on the acceptance of the offer.

14.20.3 In either case, the refunded amount will be proportional to the remaining assessment time available.

14.20.4 To ensure that application fees for short-term access are cost reflective, fees may be comprised of a number of components. For instance, the LDTEC Request Fee is comprised of a number of components and the total fee payable is the sum of those components that apply to the type(s) of LDTEC Offer(s) requested. For example:

- The LDTEC Request Fee for an LDTEC Block Offer is the basic request fee.

- The LDTEC Request Fee for an LDTEC Indicative Block Offer is the sum of the basic request fee and the additional rolling assessment fee.

- The LDTEC Request Fee payable for a combined LDTEC Block Offer and LDTEC Indicative Block Offer is the sum of the basic request fee, the additional rolling assessment fee, and the additional combined application fee.

Applications for new or modified existing Use of System Agreements

14.20.5 Users can opt to pay a fixed price application fee in respect of their application or pay the actual costs incurred. The fixed price fees for applications are detailed in the **Statement of Use of System Charges**.

14.20.6 If a User chooses not to pay the fixed fee, the application fee will be based on an advance of transmission licensees' Engineering and out-of pocket expenses and will vary according to the size of the scheme and the amount of work involved. Once the associated offer has been signed or lapsed, a reconciliation will be undertaken. Where actual expenses exceed the advance, The Company will issue an invoice for the excess. Conversely, where The Company does not use the whole of the advance, the balance will be returned to the User.

14.20.7 The Company will refund the first application fee paid (the fixed fee or the amount post-reconciliation) and consent payments made under the

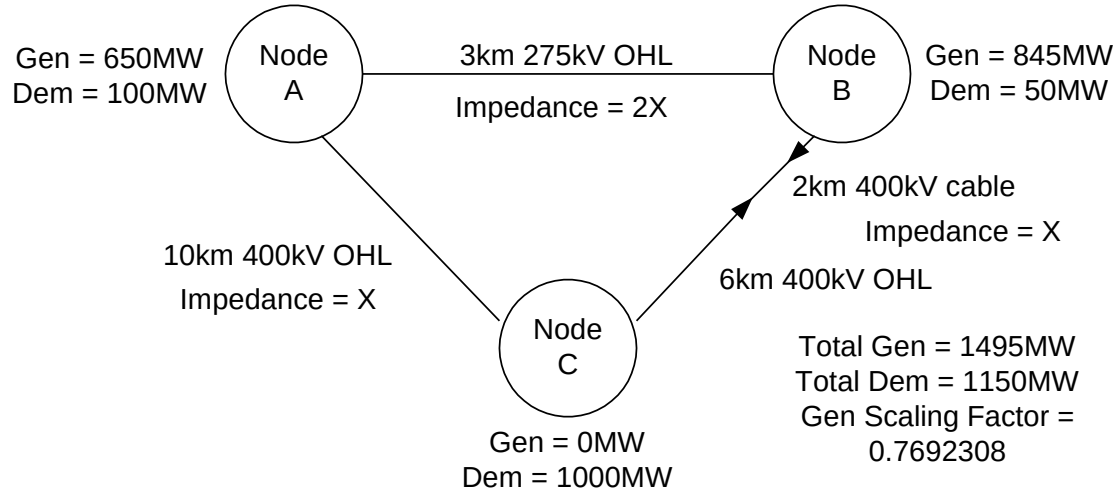
Construction Agreement for new or modified existing agreements. The refund shall be made either on commissioning or against the charges payable in the first three years of the new or modified agreement. The refund will be net of external costs.

14.20.8 The Company will not refund application fees for applications to modify a new agreement or modified existing agreement at the User's request before any charges become payable. For example, The Company will not refund an application fee to delay the provision of a new connection if this is made prior to charges becoming payable.

14.21 Transport Model Example

For the purposes of the DCLF Transport algorithm, it has been assumed that the value of circuit impedance is equal to the value of circuit reactance.

Consider the following 3-node network, where generation at node A is intermittent and generation at node B is conventional:



For both Peak Security and Year Round generation backgrounds, the nodal generation is scaled according to the relevant Scaling Factors as set out in the Security Standard, such that total system generation equals total system demand.

Peak Security background:

A fixed scaling factor of 0% is applied to intermittent generation at node A and a variable scaling factor is applied to the conventional generation at node B so that the total generation is equal to the total demand.

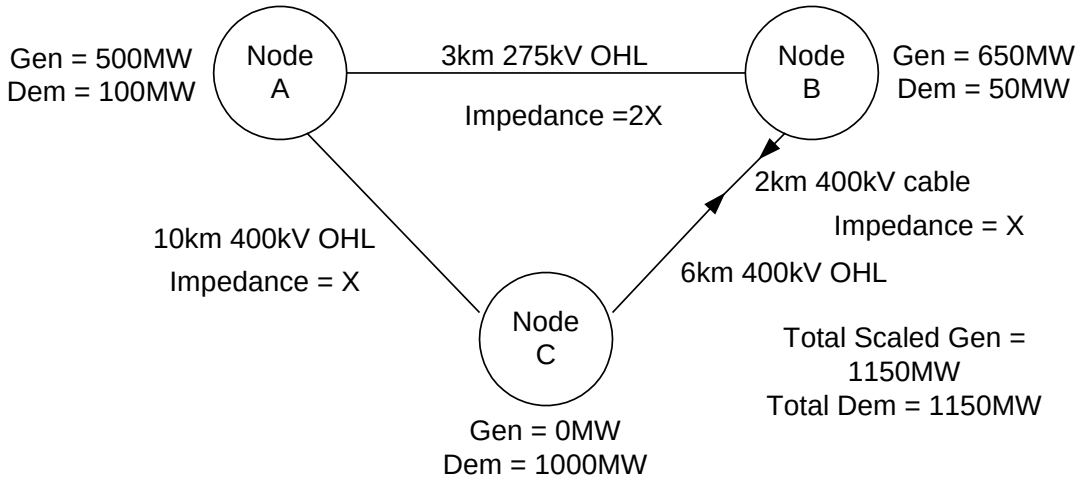
Node A Generation =

0 * 643MW = 0MW

Node B Generation = 1150/

1500 * 1500MW = 1150MW

This gives the following balanced system , where the actual generation after the application of scaling factors is shown:

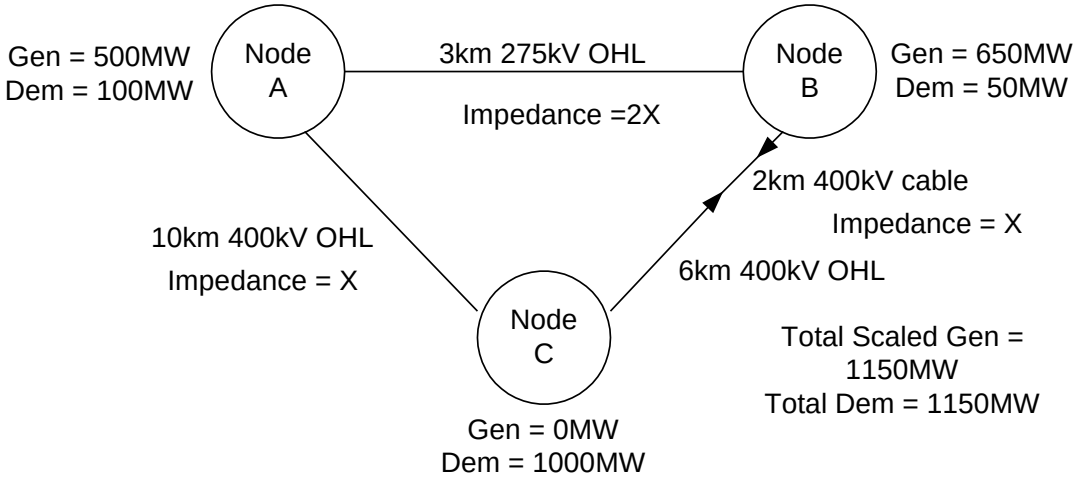


Assuming Node A is the reference node†,, each 400kV circuit has impedance X, the 275kV circuit has impedance 2X, the 400kV cable circuit expansion factor is 10 and the 275kV overhead line circuit expansion factor is 2, the DCLF transport algorithm calculates the base case power flows for Peak Security background as follows:

Node B exports, whilst Nodes A and C import. Hence the DCLF algorithm derives flows to deliver export power from Node B to meet import needs at Nodes A and C.

Step 1: Net export from Node B to Node A is 100MW; both routes BA and BC-CA have impedance 2X; hence 50MW would flow down both routes.

† For simplicity, fixed reference node has been used instead of a distributed reference node.



Step 2: Net export from Node B to Node C is 1000MW; route BC has impedance X and route BA-AC has impedance 3X; hence 750MW would flow down BC and 250MW along BA-AC

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derives the following;

Flow AC	= -50MW + 250MW	=	200MW
Flow AB	= -50MW – 250MW	=	-300MW
Flow BC	= 50MW + 750MW	=	800MW

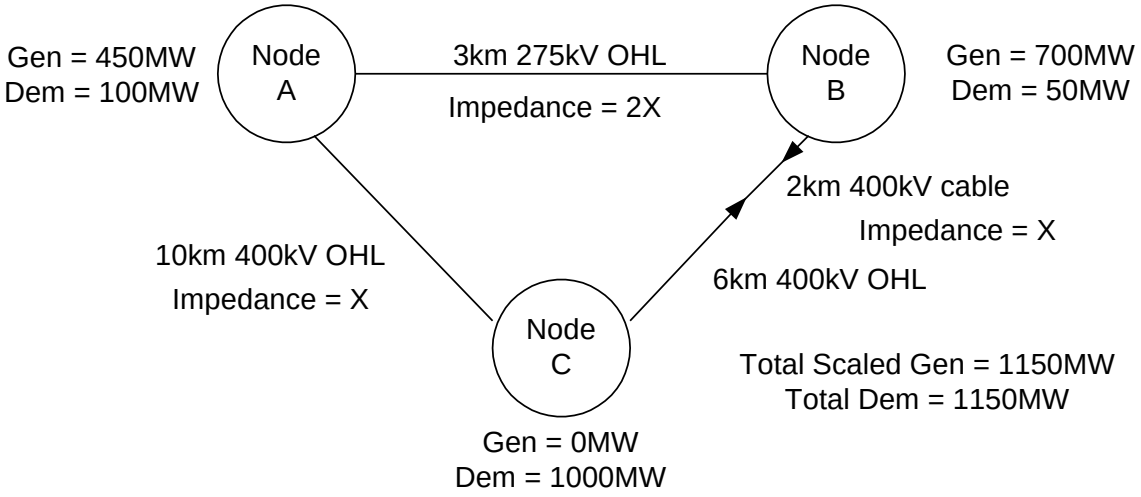
Year Round background:

A fixed scaling factor of 70% is applied to intermittent generation at node A and a variable scaling factor is applied to the conventional generation at node B so that the total generation is equal to the total demand.

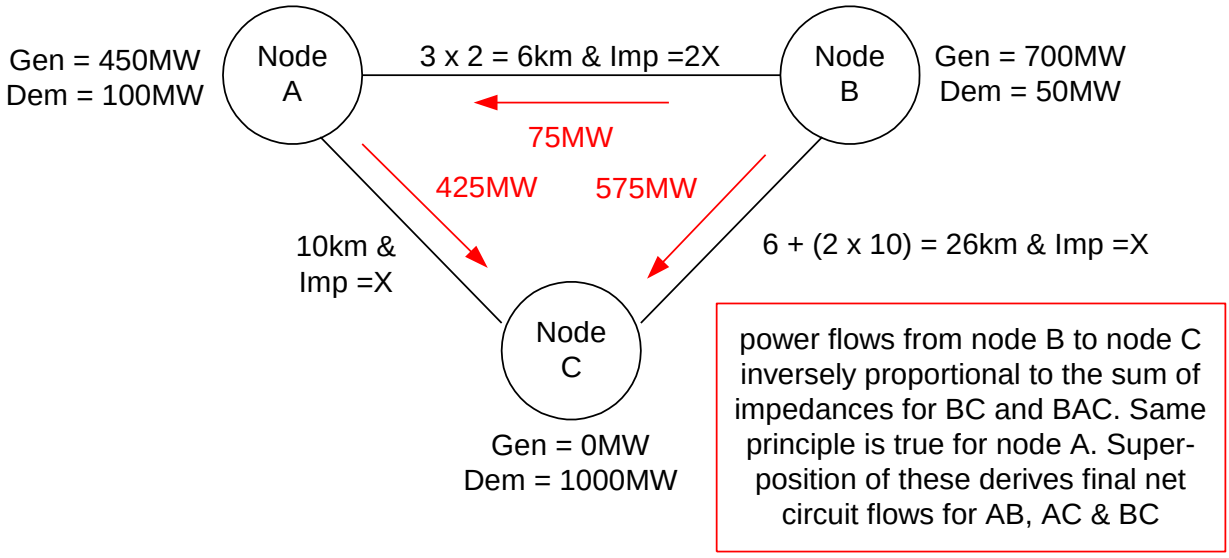
Node A Generation = 70% * 643MW = 450MW

Node B Generation = (1150-450)/1500 * 1500MW = 700MW

This gives the following balanced system, where the actual generation after the application of scaling factors is shown:



Assuming the same circuit impedances and expansion factors as used above in the Peak Security background, the DCLF transport algorithm calculates the base case power flows for Year Round background as follows:



Nodes A and B export, whilst Node C imports. Hence the DCLF algorithm derives flows to deliver export power from Nodes A and B to meet import needs at Node C.

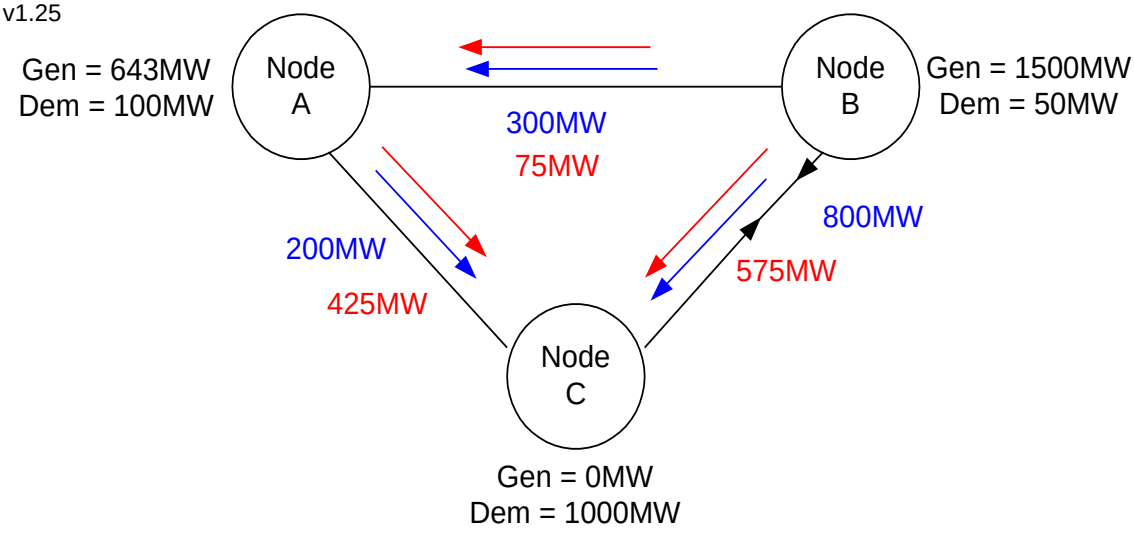
Step 1: Net export from Node A is 350MW; route AC has impedance X and route AB-BC has impedance 3X; hence 262.5MW would flow down AC and 87.5MW along AB-BC

Step 2: Net export from Node B is 650MW; route BC has impedance X and route BA-AC has impedance 3X; hence 487.5MW would flow down BC and 162.5MW along BA-AC

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derives the following;

Flow AC	= 262.5MW + 162.5MW	=	425MW
Flow AB	= 87.5MW – 162.5MW	=	-75MW
Flow BC	= 87.5MW + 487.5MW	=	575MW

Then, based on the background giving rise to highest flow, each circuit is tagged as either Peak Security or Year Round.

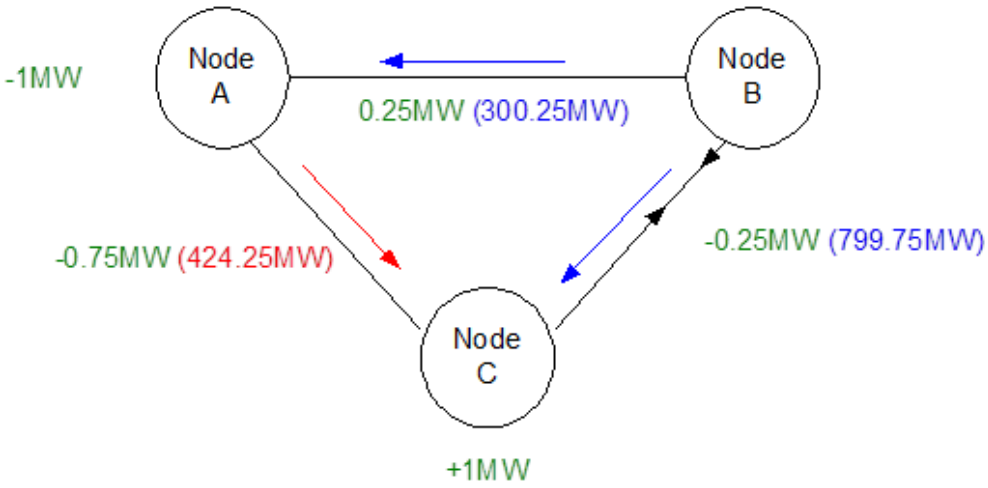


Therefore, circuits AB and BC are tagged as Peak Security and AC is tagged as Year Round.

Total Peak Security cost = (300 X 6) + (800 X 26) = 22,600MWkm
(base case)

Total Year Round cost = 425 X 10 = 4,250 MWkm
(base case)

We then 'inject' 1MW of generation at each node with a corresponding 1MW offtake (demand) at the reference node and recalculate the total Peak Security MWkm cost and Year Round MWkm cost (noting that each circuit is only in one background). The difference from the base case for Peak Security and Year Round costs is the marginal km or shadow cost for Peak Security and Year Round networks respectively. The size and direction of the incremental MW is shown below along with the resultant when superimposed on the relevant base case flow (i.e. higher of the Peak Security and Year Round) depicted in brackets:.



To calculate relevant Peak Security and Year Round the marginal km for node C:

Total Peak Security Cost = (300.25 x 6) + (799.75 x 26) =22,595

Total Year Round Cost = 424.25 X 10 = 4,242.5 MWkm

Marginal Peak Security cost = Incremental total Peak Security cost – Base case total Peak Security cost

= 22595 – 22600 = -5MWkm

Marginal Year Round cost = Incremental total Year Round cost – Base case total Year Round cost

= 4242.5 – 4250 = -7.5MWkm

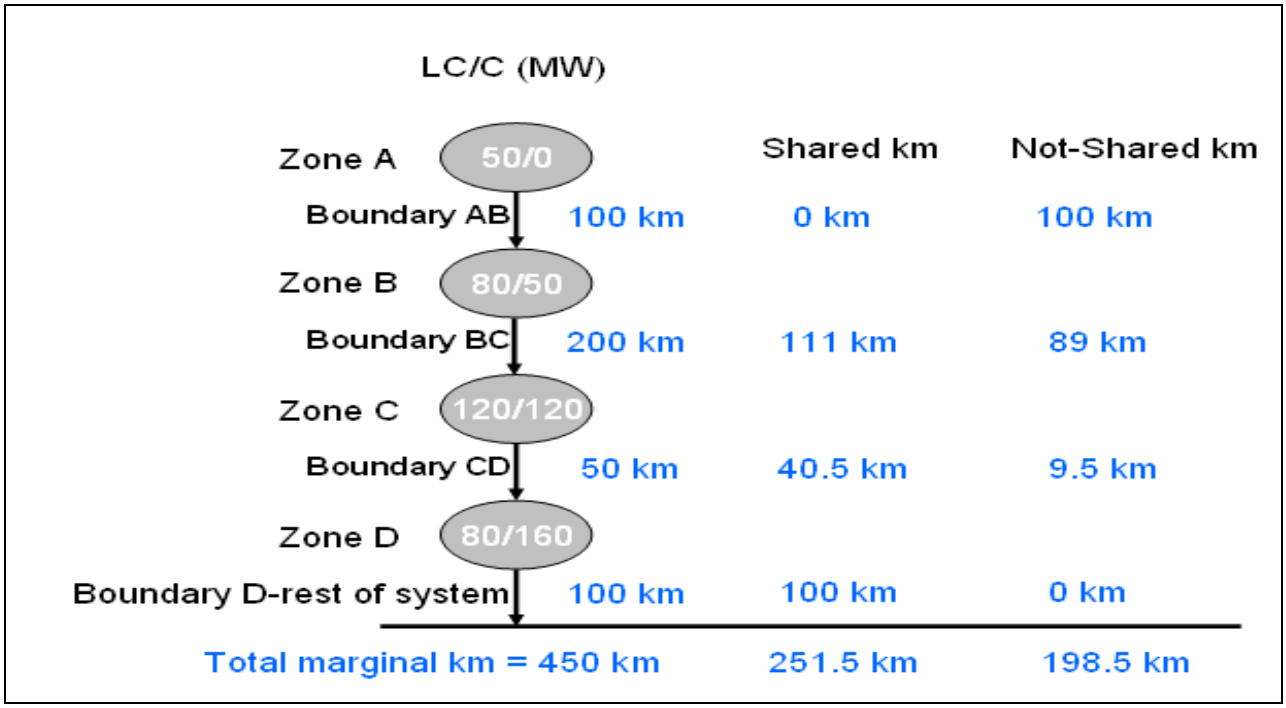
Thus the overall cost has reduced by .5 for Peak Security (i.e. the marginal km = 5) and by 7.5 for Year Round (i.e the Year Round marginal km = -7.5)

14.22 Illustrative Calculation of Boundary Sharing Factors (BSFs) and Shared / Not-Shared incremental km

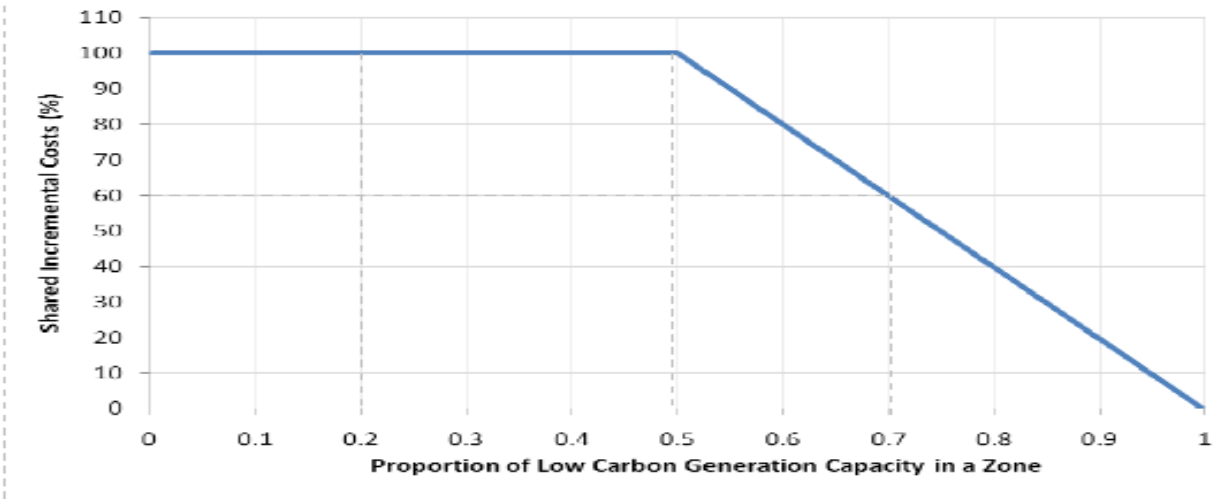
The following illustrative example shows how the boundary sharing factors and shared / not-shared incremental km are calculated for the transmission system described in the table below.

Generation Charging Zone	A	B	C	D
Zonal MWkm	450	350	150	100

The digram below shows the expanded connectivity of this transmission system.



up



The above figure illustrates how the Year Round marginal km are split into Shared and Not-Shared.

(a) For Boundary AB (where 50MW of the generation is Low Carbon (LC) and 0MW of the generation is Carbon (C) and Year Round boundary marginal km = 100km) -

$$\frac{LC}{(LC+C)}=\frac{50}{50+0}=1$$ which is greater than 0.5, therefore the following formula will be used to calculate the Boundary Sharing Factor (BSF) –

$$BSF=-2\times\left(\frac{LC}{LC+C}\right)+2 = -2\times\left(\frac{50}{50+0}\right)+2=0\ (0\%)$$

Year Round Shared marginal km = 0.0 * 100km = 0 km
Year Round Not-Shared marginal km = (100 – 0)km = 100 km

(b) For Boundary BC (where 130MW of generation is Low Carbon (LC) and 50MW of generation is Carbon (C) and Year Round boundary marginal km = 200km) –

$$\frac{LC}{(LC+C)}=\frac{(50+80)}{(50+80)+(0+50)}=0.722$$ which is greater than 0.5, therefore the following formula will be used to the BSF –

$$BSF=-2\times\left(\frac{LC}{LC+C}\right)+2 = -2\times\left(\frac{130}{130+50}\right)+2 = 0.556\ (55.6\%)$$

Year Round Shared marginal km = 0.556 * 200km = 111 km
Year Round Not-Shared marginal km = (200 – 111)km = 89 km

(c) For Boundary CD (where 250MW of generation is Low Carbon (LC) and 170MW of generation is Carbon (C) and Year Round boundary marginal km = 50km) –

$$\frac{LC}{(LC+C)}=\frac{(50+80+120)}{(50+80+120)+(0+50+120)}=0.595$$ which is greater than 0.5, therefore the following formula will be used to calculate the BSF –

$$BSF=-2\times\left(\frac{LC}{LC+C}\right)+2 = -2\times\left(\frac{250}{250+170}\right)+2=0.810\ (81\%)$$

Year Round Shared marginal km = 0.81 * 50km = 40.5 km
Year Round Not-Shared marginal km = (50 – 40.5)km = 9.5 km

(d) For Doundary D-rest of system (where 330MW of generation is Low Carbon (LC) and 330MW of generation is Carbon (C) and Year Round boundary marginal km = 100km) –

$$\frac{LC}{(LC+C)}=\frac{(50+80+120+80)}{(50+80+120+80)+(0+50+120+160)}=0.5$$ therefore it is at the threshold at which maximum sharing occurs between LC and C generation. Therefore 100% of the Year Round zonal marginal km will be shared. (i.e. BSF=1.0);

Year Round Shared marginal km = 1.0 * 100 = 100 km
Year Round Not-Shared marginal km = (100 – 100)km = 0 km
The shared zonal marginal km for each generation charging zone will be the sum of the relevant shared boundary marginal km as shown in the table below (assuming the node below D is the

centre of the system i.e. zonal MWkm of 0). These not-shared zonal incremental km are then use to calculate wider £/kW generation tariffs.

Boundary/Zone	A	B	C	D
A-B	0			
B-C	111	111		
C-D	40.5	40.5	40.5	
D-rest of system	100	100	100	100
Shared Zonal MWkm	251.5	251.5	140.5	100
Total Zonal MWkm	450	350	150	100

The not-shared zonal marginal km for each generation charging zone will be the sum of the relevant not-shared boundary marginal km as shown in the table below (assuming the node below D is the centre of the system i.e. zonal MWkm of 0). These not-shared zonal incremental km are then use to calculate wider £/kW generation tariffs.

Boundary/Zone	A	B	C	D
A-B	100			
B-C	89	89		
C-D	9.5	9.5	9.5	
D-rest of system	0	0	0	0
Not-Shared Zonal MWkm	198.5	98.5	9.5	0
Total Zonal MWkm	450	350	150	100

14.23 Example: Calculation of Zonal Generation Tariff

Wider
Let us consider all nodes in a generation zone in this example.

The table below shows a sample output of the transport model comprising the node, the Peak Security wider nodal marginal km and Year Round wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal across distributed reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand, for both Peak Security and Year Round generation backgrounds..

Gen Zone	Node	Wider Nodal Marginal km (Peak Security)	Scaled Generation (Peak Security)	Wider Nodal Marginal km (Year Round)	Scaled Generation (Year Round)
4	ABNE10	5.73	0.00	459.90	0.00
4	CLAY1S	239.67	0.00	306.47	0.00
4	CLUN1S	46.41	22.90	502.16	18.76
4	COUA10	45.39	0.00	423.30	0.00
4	DYCE1Q	162.70	0.00	357.81	0.00
4	ERRO10	46.82	56.13	534.03	45.99
4	FIDD1B	91.88	0.00	220.59	0.00
4	FINL1Q	79.69	12.35	495.63	10.12
4	GRIF1S	33.31	0.00	521.16	71.40
4	KIIN10	79.69	0.00	495.63	0.00
4	LOCH10	79.69	35.18	495.63	28.82
4	MILC10	117.69	0.00	328.86	0.00
4	PERS20	266.00	0.00	384.05	0.00
4	TUMB1Q	46.82	0.00	536.27	0.00
		Totals	**126.56**		**175.09**

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For this example zone this would be as follows:

Gen Zone	Node	Wider Nodal Marginal km (Peak Security)	Scaled Generation (Peak Security) (MW)	Gen Weighted Wider Nodal Marginal km (Peak Security)	Wider Nodal Marginal km (Year Round)	Scaled Generation (Year Round) (MW)	Gen Weig Wider N Margin (Year Ro
4	CLUN1S	46.41	22.90	8.39	502.16	18.76	5
4	ERRO10	46.82	56.13	20.76	534.03	45.99	14
4	FINL1Q	79.69	12.35	7.77	495.63	10.12	2
4	GRIF1S	N/A	N/A	N/A	521.16	71.40	21
4	LOCH10	79.69	35.18	22.15	495.63	28.82	8
		Totals	**126.56**			**175.09**	

i.e. 79.69 x 35.18 / 126.56

(ii) sum the generation weighted wider nodal shadow costs to give Peak Security and Year Round zonal figures

For this example zone this would be:

.**Peak Security**: (8.39 + 20.76+7.77+22.15) km = **59.07km**
Year Round: (53.80 + 140.27 + 28.65 + 212.52 + 81.58) = **516.82 km**

(iii) In this example we have assumed that accounting for sharing in the Year Round background gives:

Year Round Shared marginal km = 344.56km
Year Round Not-Shared marginal km = 172.26km

)

(iv) calculate the initial Peak Security wider transport tariff, Year Round Shared wider transport tariff and Year Round Not-Shared wider transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 4 and assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.8:

(a) Initial Peak Security wider tariff - $\frac{59.07 \text{ km} * £10.07/\text{MWkm} * 1.8}{1000}$ = **£1.071/kW**

b) Initial Year Round Shared wider tariff -

$\frac{344.56 \text{ km} * £10.07/\text{MWkm} * 1.8}{1000}$ = **£6.245/kW**

c) Initial Year Round Not-Shared wider tariff -

$$\frac{172.26 \text{ km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£1.309/kW}$$

Local

(v) If we assume (for the sake of this example) that the generator connecting at CLUN1S is a thermal plant with a Peak Security flag of 1 and an Annual Load Factor (ALF) of 60%, which connects via 10km of 132kV 100MVA rated single circuit overhead line from the nearest MITS node, with no redundancy, the substation is rated at less than 1320MW, and there is no other generation or demand connecting to this circuit, then:

a) referencing the table in paragraph 14.15.118, the local substation tariff will be £0.133/kW; and

b) running the transport model with a local circuit expansion factor of 10.0 applied to the 10km of overhead line connecting CLUN1S to the nearest MITS node and the wider circuit expansion factors applied to all other circuits, gives a local nodal maginal cost of 100MWkm. This is the additional MWkm costs associated with the node's local assets. Applying the expansion constant of £10.07/MWkm and local security factor of 1.0 and dividing by 1000 gives a local circuit tariff of £1.007/kW.

Residual

(vi) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from generation (calculated as c.27% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariffs divided by total expected generation.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (27% x £1067m) = £288m. Assuming the total recovery from both wider generation transport tariffs (i.e. wider Peak Security tariff, wider Year Round Shared tariff and wider Year Round Not-Shared tariff) and local generation tariffs (i.e. local substation tariff and local circuit tariff) is £70m and total forecast chargeable generation capacity is 67000MW, the Generation residual tariff would be as follows:

$$\frac{£288 - £70m}{65000MW} = £3.35/kW$$

(vii) Therefore the charges for thermal plant with a TEC of 100MW and an ALF of 60%, connecting at CLUN1S is:

= Wider Peak Security Tariff * PS Flag * TEC
= Wider Year Round Shared Tariff * ALF * TEC
= Wider Year Round Not-Shared Tariff * TEC
= Local substation Tariff * TEC
= Local circuit Tariff * TEC
= Residual Tariff * TEC

For this example
, the above changes are -

= 1.071 * 1 * 100,000

= 1.309 * 100, 000
= 0.133*100,000
= 1.007 **<u>* 100,000</u>**

= 3.35 * 100,000

(effectively, £10.617/kW * 100,000kW = £1,061,700)

(viii) Alternatively, if we assume that the generator connecting at CLUN1S is an intermittent wind generation plant (instead of a thermal plant) with a TEC of 100MW, PS Flag of 0 and an ALF of 30%, then the charges payable will be –

= 1.071 * 0 * 100,000
= 6.245 * 0.3 * 100,000
= 1.309 * 100,000
= 0.133 * 100,000
= 1.007 * 100,000
= 3.35 * 100,000

(effectively, £7.673/kW * 100,000kW = £767,300)

14.24 Example: Calculation of Zonal Gross Demand Tariff

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

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

Where the Demand (MW) is negative this indicates that the Demand node is Exporting rather than importing.

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

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Net Demand (MW)
14	ABHA4A	-77.25	-230.25	127
14	ABHA4B	-77.27	-230.12	127
14	ALVE4A	-82.28	-197.18	100
14	ALVE4B	-82.28	-197.15	100
14	AXMI40_SWEB	-125.58	-176.19	97
14	BRWA2A	-46.55	-182.68	96
14	BRWA2B	-46.55	-181.12	96
14	EXET40	-87.69	-164.42	340
14	HINP20	-46.55	-147.14	0
14	HINP40	-46.55	-147.14	0
14	INDQ40	-102.02	-262.50	444
14	IROA20_SWEB	-109.05	-141.92	462
14	LAND40	-62.54	-246.16	262
14	MELK40_SWEB	18.67	-140.75	83
14	SEAB40	65.33	-140.97	304
14	TAUN4A	-66.65	-149.11	55
14	TAUN4B	-66.66	-149.11	55
		Totals		**2748**

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

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

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

(ii) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

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

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

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

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

a) Peak Security tariff –

$$-\frac{120\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \textbf{-£2.47/kW}$$

b) Year Round tariff -

$$-\frac{82 * £10.07/\text{MWkm} * 1.8}{1000} = \textbf{-£1.49/kW}$$

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

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

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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

For zone 1:

-£2.47/kW + -£1.49/kW + £12.98/kW = **£9.32/kW**

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

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

14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

	Forecast HH Triad Gross Demand HHD_F (kW)	HH Gross Demand Monthly Invoiced Amount (£)	Forecast HH Triad Embedded Export $HHEE_F$ (kW)	HH Embedded Generation Monthly Invoiced Amount (£)	Forecast NHH Energy Consumption $NHHC_F$(kWh)	NHH Monthly Invoiced Amount (£)	Net Monthly Invoiced Amount (£)
Apr	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
May	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
Jun	12,000	10,000	-600	(250)	15,000,000	15,000	24,750
Jul	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Aug	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Sep	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Oct	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Nov	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Dec	12,000	10,000	-600	(250)	18,000,000	19,000	28,750
Jan	7,200	(6,000)	-600	(250)	18,000,000	19,000	12,750

Feb Mar	7,200 7,200	(6,000) (6,000)	-600 -600	(250) (250)	18,000,000 18,000,000	19,000 19,000	12,750 12,750
Total		72,000		(3,000)		216,000	297,000

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

= £18,000

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

$$\text{NHHC Reconciliation Charge} = \frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$$

$$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$$

$$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 = £500 - £12,000).

Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand = (9,500kW - 9,000kW) x £10.00/kW

Reconciliation Charge = £5,000

Final HH Embedded Export = (-550kW - -500kW) x £5.00/kW

Reconciliation Charge = -£250
Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} - 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1, 150 (£5,000 + -£250 + -£3,600)..

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

Terminology:

HHD_A = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

HHD_F = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$HHEE_A$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$HHEE_F$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$NHHC_A$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$NHHC_F$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

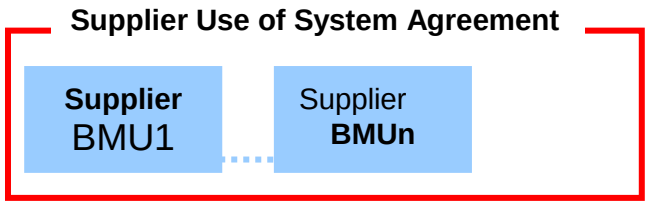
£/kW Tariff = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

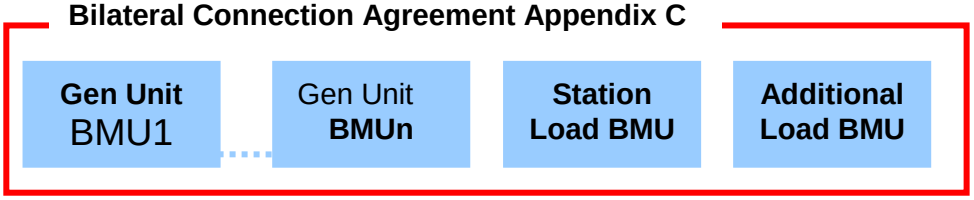
p/kWh Tariff = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

SUPPLIER	
	
Demand Charges See **14.17.13 and 14.17.18.**	Generation Charges None.

POWER STATION WITH A BILATERAL CONNECTION AGREEMENT	
	
Demand Charges See **14.17.18.**	Generation Charges See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.** For generators in positive zones, see **14.18.10 to 14.18.12.** For generators in negative zones, see **14.18.13 to 14.18.17.**

PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT

Bilateral Embedded Generation Agreement Appendix C

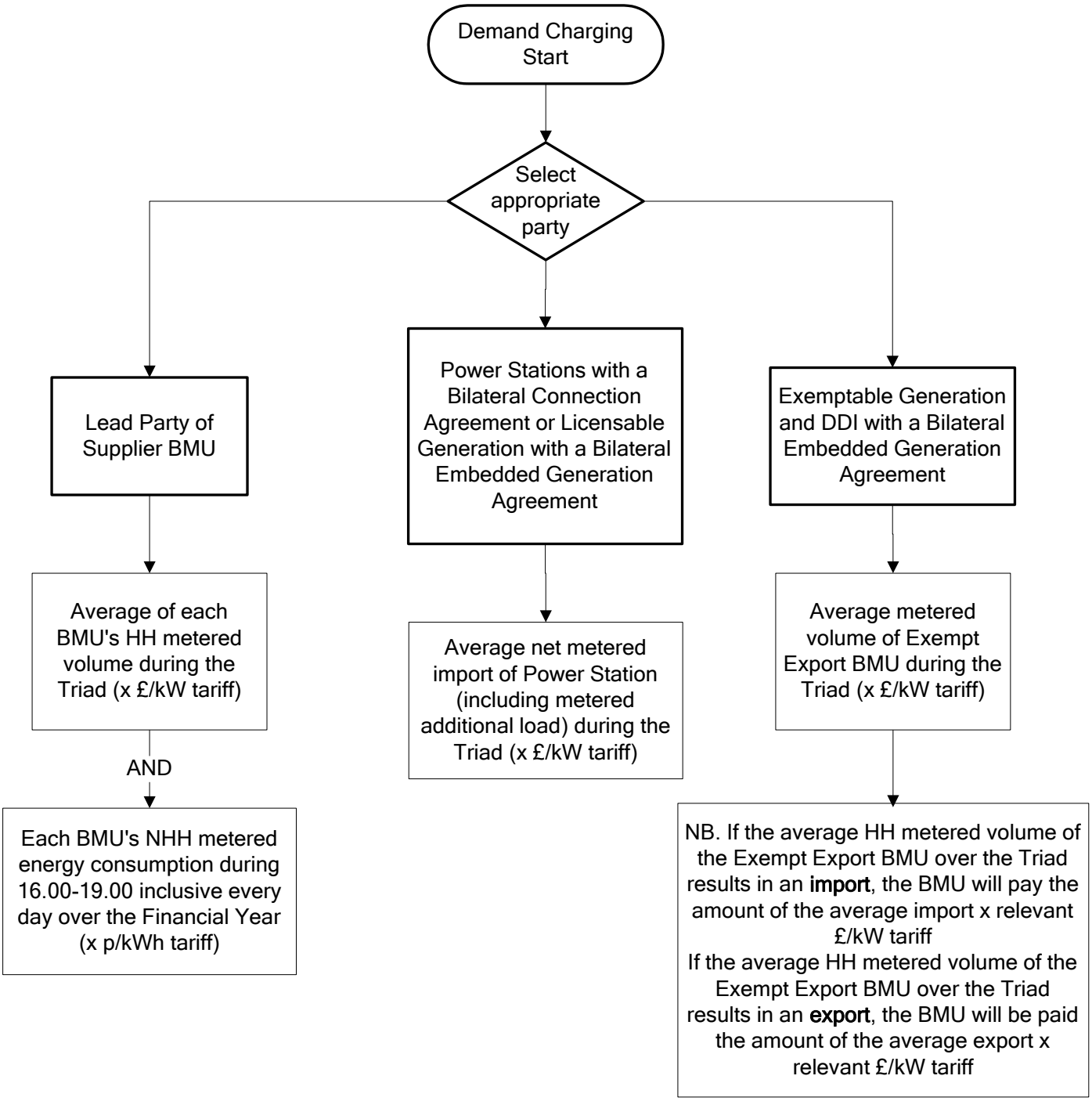
Demand Charges	Generation Charges
See **14.17.14, 14.17.15 and 14.17.18.**	See **14.18.1 ii).** For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.** For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.**

14.27 Transmission Network Use of System Charging Flowcharts

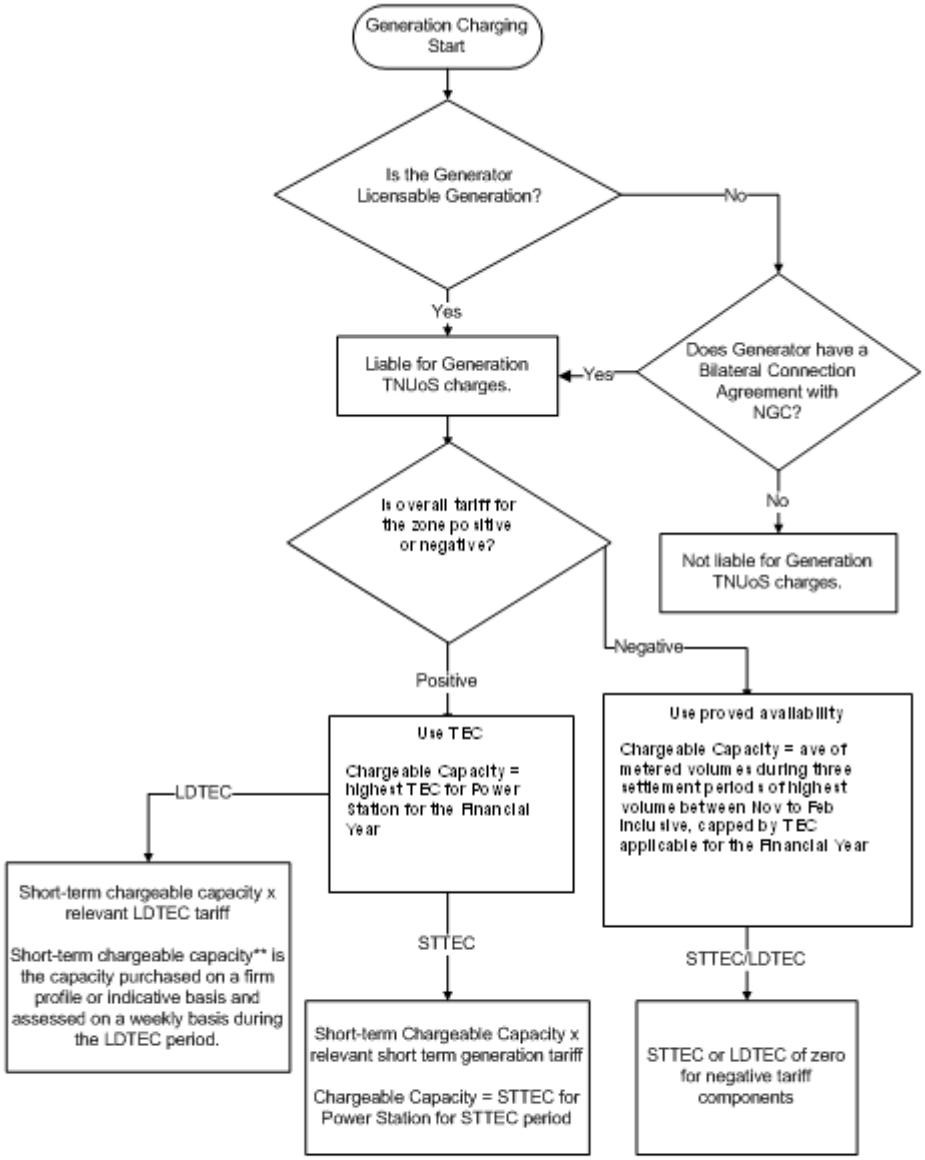
The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

Demand Charges



Generation Charges



14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

Example (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

Latest date for which settlement data is available.

ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

Example:

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

Example:

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = -150 * -7,200,000 /- 6,000,000

F = -180 kW

where:

M = -150 kW (period 1st July 2005 to 31st July 2005)

T = -7,200,000 kW (period November 2004 to February 2005)

W = -6,000,000 kW (period 1st July 2004 to 31st July 2004)

iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

Example:

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

14.29 Stability & Predictability of TNUoS tariffs

Stability of tariffs

The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity. This appendix seeks to highlight those elements.

Each node of the transmission network is assigned to a zone. The result of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters. The criteria used to establish generation zones are part of the methodology and are described in Paragraph 14.15.42.

These zones are themselves fixed for the duration of the price control period. The methodology does, however, allow these to be revisited in exceptional circumstances to ensure that the charges remain reasonably cost reflective or to accommodate changes to the network. In rare circumstances where such a re-zoning exercise is required, this will be undertaken in such a way that minimises the adverse impact on Users. This is described in Paragraph 14.15.45.

In addition to fixing zones, other key parameters within the methodology are also fixed for the duration of the price control period or annual changes restricted in some way. Specifically:

- the expansion constant, which reflects the annuitised value of capital investment required to transport 1MW over 1km by a 400kV over-head line, changes annually according to RPI. The other elements used to derive the expansion constant are only reviewed at the beginning of a price control period to ensure that it remains cost-reflective. This review will consider those components outlined in Paragraph 14.15.59 to Paragraph 14.15.69.

- the expansion factors, which are set on the same basis of the expansion constant and used to reflect the relative investment costs in each TO region of circuits at different transmission voltages and types, are fixed for the duration price control. These factors are reviewed at the beginning of a price control period and will take account of the same factors considered in the review of the expansion constant.

- the locational security factor, which reflects the transmission security provided under the NETS Security and Quality of Supply Standard, is fixed for the duration of the price control period and reviewed at the beginning of a price control period.

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within the Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of “indicative” tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority’s veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[4] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[4] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Section 2 – The Statement of the Balancing Services Use of System Charging Methodology

14.29 Principles

14.29.1 The Transmission Licence allows The Company to derive revenue in respect of the Balancing Services Activity through the Balancing Services Use of System (BSUoS) charges. This statement explains the methodology used in order to calculate the BSUoS charges.

14.29.2 The Balancing Services Activity is defined in the Transmission Licence as the activity undertaken by The Company as part of the Transmission Business including the operation of the transmission system and the procuring and using of Balancing Services for the purpose of balancing the transmission system.

14.29.3 The Company keeps the electricity system in balance (energy balancing) and maintains the quality and security of supply (system balancing). The Company is incentivised on the procurement and utilisation of services to maintain the energy and system balance and other costs associated with operating the system. Users pay for the cost of these services and any incentivised payment/receipts through the BSUoS charge.

14.29.4 All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with either Interconnectors or Virtual Lead Parties) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

14.29.5 BSUoS charges comprise the following costs:

(i) The Total Costs of the Balancing Mechanism
(ii) Total Balancing Services Contract costs
(iii) Payments/Receipts from The Company's incentive schemes
(iv) Internal costs of operating the System
(v) Costs associated with contracting for and developing Balancing Services
(vi) Adjustments
(vii) Costs invoiced to The Company associated with Manifest Errors and Special Provisions.
(viii) BETTA implementation costs

14.30 Calculation of the Daily Balancing Services Use of System charge

Calculation of the Daily Balancing Services Use of System charge

14.30.1 The BSUoS charge payable by customer c, on Settlement Day d, will be calculated in accordance with the following formula:

$$BSUoSTOT_{cd} = \sum_{i \in c} \sum_{j \in d} BSUoSTOT_{ij}$$

Where:

i	-	refers to the individual BM Unit
j	-	refers to an individual Settlement Period
$\sum_{i \in c} \sum_{j \in d}$	-	refers to the sum over all BM units 'i', for which customer 'c' is the Lead Party* summed over all Settlement Periods 'j' on a Settlement Day 'd'

14.30.2 A customer's charge is based on their proportion of BM Unit Metered Volume for each Settlement Period relative to the total BM Unit Metered Volume for each Settlement Period, adjusted for transmission losses by the application of the relevant Transmission Losses Multiplier.

For all liable importing and exporting BM Units in delivering Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

For all liable importing and exporting BM Units in offtaking Trading Units in a Settlement Period:

$$BSUoSTOT_{ij} = \frac{-1 * BSUoSTOT_j * QMBSUoS_{ij} * TLM_{ij}}{\left\{\left|\sum^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum^{-}(QMBSUoS_{ij} * TLM_{ij})\right|\right\}}$$

Where:

$BSUoSTOT_j$	Total BSUoS Charge applicable for Settlement Period j
$QMBSUoS_{ij}$	BM Unit Metered Volume (QM_{ij})** for BSUoS Liable BM Units, minus imports to SVA or CVA Storage Facilities, as relevant, registered to that BM Unit
TLM_{ij}	Transmission Loss Multiplier **

$\sum^{+}$ - refers to the sum over all BM Units that are in delivering Trading Units in Settlement Period 'j'

$\sum^{-}$ - refers to the sum over all BM Units that are in offtaking Trading Units in Settlement Period 'j'

* or CUSC party associated with the BMUnits (listed in Appendix C of the BEGA) who is exempt from also being a BSC Party

** Detailed definition in Balancing and Settlement Code Annex X2 – Technical Glossary

'delivering' and 'offtaking' in relation to Trading Units have the meaning set out in the Balancing and Settlement Code (excluding all Interconnector BMUs and Trading Units)

14.30.3 For the avoidance of doubt, BM Units that are registered in Trading Units will be charged on a net Trading Unit basis i.e. if a BM Unit is exporting to the system and is within a Trading Unit that is offtaking from the system then the BM Unit in essence would be paid the BSUoS charge. Conversely, if a BM Unit is importing from the system in a delivering Trading Unit then the BM Unit in essence would pay the BSUoS charge.

Interconnector BM Units

14.30.4 BM Unit and Trading Units associated with Interconnectors, including those associated with the Interconnector Error Administrator, are not liable for BSUoS charges. BM Units, including Secondary BM Units, which are associated with Virtual Lead Parties are not liable for BSUoS charges.

Storage Facilities

14.30.5 The BM Units associated with CVA Storage Facilities will not be charged BSUoS against imported volumes where the imports of that BM Unit are solely for the purposes of operating that CVA Storage Facility.

14.30.6 Where the BM Unit is a Supplier BM Unit and one or more SVA Storage Facilities are registered to that Supplier BM Unit, the Supplier shall be liable for BSUoS in accordance with 14.30.3, net of any imports to such SVA Storage Facilities where those imports are solely for the purposes of operating that Storage Facility

14.30.7 In all cases, where a facility ceases to be a CVA Storage Facillity, the exemption in para 14.30.5 shall no longer apply. The User , shall inform The Company as soon as is reasonably practicable and in any event no fewer than 5 Working Days from the date on which the facility ceased to be a CVA Storage Facility

Total BSUoS Charge (Internal + External) for each Settlement Period ($BSUoSTOT_{jd}$)

~~14.30.5~~14.30.8 The Total BSUoS charges for each Settlement Period ($BSUoSTOT_{jd}$) for a particular day are calculated by summing the external BSUoS charge ($BSUoSEXT_{jd}$) and internal BSUoS charge ($BSUoSINT_{jd}$) for each Settlement Period.

$$BSUoSTOT_{jd} = BSUoSEXT_{jd} + BSUoSINT_{jd}$$

External BSUoS Charge for each Settlement Period ($BSUoSEXT_{jd}$)

~~14.30.6~~14.30.9 The External BSUoS Charges for each Settlement Period ($BSUoSEXT_{jd}$) are calculated by taking each Settlement Period System Operator BM Cash Flow ($CSOBM_j$) and Balancing Service Variable Contract Cost ($BSCCV_j$) and allocating the daily elements on a MWh basis across each Settlement Period in a day.

$$BSUoSEXT_{jd} = CSOBM_{jd} + BSCCV_{jd}$$
$$+\left[(IncPayExt_d + BSCCA_d + ET_d - OM_d + BSC_d + SOTOC_d) \right.$$
$$*\left\{ \left|\sum\nolimits^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\} /$$
$$\left.\sum\nolimits_{j \in d}\left\{ \left|\sum\nolimits^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\} \right]$$

Calculation of the daily External Incentive Payment ($IncPayExt_d$)

~~14.30.7~~14.30.10 $IncPayExt_t$ is the external incentive payment for the Current **Financial Year**. This amount of this will be determined in line with Transmission Licence Special Condition 4M.

~~14.30.8~~14.30.11 For **Financial Year** 2018/19 $IncPayExt_d$ is calculated by dividing $IncPayExt_t$ for **Financial Year** 2018/19 by the amount of days remaining within the current incentive scheme year. $IncPayExt_d$ will be evenly spread and then apportioned by volume as per the current process (14.30.2).

Internal BSUoS Charge for each Settlement Period ($BSUoSINT_{jd}$)

~~14.30.9~~14.30.12 The Internal BSUoS Charges ($BSUoSINT_{jd}$) for each Settlement Period j for a particular day are calculated by taking the incentivised and non-incentivised SO Internal Costs for each Settlement Day allocated on a MWh basis across each Settlement Period in a day.

$$BSUoSINT_{jd} = \left[(SOPU_d + SOMOD_d + SOEMR_d + SOEMRCO_d + SOTRU_d) * RPIF_t\right]$$
$$* \left\{ \left|\sum\nolimits^{+}(QMBSUoS_{ijd} * TLM_{ijd})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ijd} * TLM_{ijd})\right| \right\}$$
$$/ \sum\nolimits_{j \in d} \left\{ \left|\sum\nolimits^{+}(QMBSUoS_{ij} * TLM_{ij})\right| + \left|\sum\nolimits^{-}(QMBSUoS_{ij} * TLM_{ij})\right| \right\}$$

Inclusion of Profiling Factors

~~14.30.10~~14.30.13 Profiling factors have been included to give an effective mechanism for calculating a representative level of the incentive payments to/from The Company according to the time of year. All PFT_k are assumed to be one for the duration of the current external incentive scheme

14.31 Settlement of BSUoS

Settlement and Reconciliation of BSUoS charges

14.31.1 There are two stages of the reconciliation of BSUoS charges described below:

- Initial Settlement (SF)
- Final Reconciliation (RF)

Initial Settlement of BSUoS

14.31.2 The Company will calculate initial settlement (SF) BSUoS charges in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Initial Settlement Run and the Initial Volume Allocation Run.

Reconciliation of BSUoS Charges

14.31.3 Final Reconciliation will result in the calculation of a reconciled charge for each settlement day in the scheme year. The Company will calculate Final Reconciliation (RF) BSUoS charges (with the inclusion of interest as defined in the CUSC) in accordance with the methodology set out in section 14.30 above, using the latest available data, including data from the Final Reconciliation Settlement Run and the Final Reconciliation Volume Allocation Run.

Unavailability of Data

14.31.4 If any of the elements required to calculate the BSUoS charges in respect of any Settlement Day have not been notified to The Company in time for it to do the calculations then The Company will use data for the corresponding Settlement Day in the previous week. If no such values for the previous week are available to The Company then The Company will substitute such variables as it shall, at its reasonable discretion, think fit and calculate Balancing Services Use of System charges on the basis of these values. When the actual data becomes available a reconciliation run will be undertaken.

Disputes

14.31.5 If The Company or any customer identifies any error which would affect the total Balancing Services Use of System charge on a Settlement Day then The Company will recalculate the charges following resolution of the error. Revised invoices and/or credit notes will be issued for the change in charges, plus interest as set out in the CUSC. The charge recalculation and issuing of revised invoices and/or credit notes will not take place for any day where the total change in the Balancing Services charge is less than £2000.

Relationship between the Statement of the Use of System Charging Methodology and the Transmission Licence

14.31.6 BSUoS charges are made on a daily basis and as such of this Statement sets out the details of the calculation of such charges on a daily basis. Customers may, when verifying charges for Balancing Services Use of System refer to the Transmission Licence which sets out the maximum allowed revenue that The Company may recover in respect of the Balancing Services Activity.

14.31.7 The Company has, where possible and appropriate, attempted to ensure that acronyms allocated to variables within the Balancing Services charging software, and associated reporting, match with the acronyms given to those variables used within this statement.

14.31.8 Balancing Services Use of System Acronym Definitions

For the avoidance of doubt "as defined in the BSC" relates to the Balancing and Settlement Code as published from time to time.

EXPRESSION	ACRONYM	Unit	Definition
BETTA Preparation Costs	BI	£	As defined in the Transmission Licence
Balancing Mechanism Unit	BM Unit or BMU		As defined in the BSC
Black Start Costs	BSC	£	As defined in the Transmission Licence (means he allowed revenue from and associated with Black Start services in accordance with paragraph 4G.5 of Special Condition 4G (Black Start Allowed Revenue Cost Incentive))
Balancing service contract costs – non-Settlement Period specific	$BSCCA_d$	£	Non Settlement Period specific Balancing Contract Costs for settlement day d less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing Service Contract Cost	$BSCC_j$	£	Balancing Service Contract Cost from purchasing Ancillary services applicable to a Settlement Period j less any costs incurred within these values relating to Supplementary Balancing Reserve and Demand Side Balancing Reserve
Balancing service contract costs – Settlement Period specific	$BSCCV_{jd}$	£	Settlement Period j specific Balancing Contract Costs for settlement day d
External Balancing Services Use of System charge	$BSUoSEXT_{jd}$	£	External System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Internal Balancing Services Use of System charge	$BSUoSINT_{jd}$	£	Internal System Operator (SO) Balancing Services Use of System charge applicable to Settlement Period j for settlement day d
Total Balancing Services Use of System charge	$BSUoSTOT_{cd}$	£	The sum determined for each customer, c, in accordance with this Statement and payable by that customer in respect of each Settlement Day d, in accordance with the terms of the Supplemental Agreement
Total Balancing Services Use of System charge	$BSUoSTOT_j$	£	Total Balancing Services Use of System Charge applicable for Settlement Period j
System Operator BM Cash Flow	$CSOBM_j$	£	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001 less any costs incurred within these values relating to

EXPRESSION	ACRONYM	Unit	Definition
			Supplementary Balancing Reserve and Demand Side Balancing Reserve
Daily balancing services adjustment	ET_d	£	Is the contribution on Settlement Day, d, to the value of ET_t where ET_t is determined pursuant to part B of Special Condition 4C of the Transmission Licence
Forecast incentivised Balancing Cost	FBC_d	£	Forecast incentivised Balancing Cost for duration of the Incentive Scheme as at settlement day d
Allowed Income Adjustment relating to the SO-TO Code	IAT	£	As defined in the Transmission Licence
External incentive payment	$IncPayExt_t$	£	As defined in the Transmission Licence.
Daily External incentive payment	$IncPayExt_d$	£	External Incentive payment for Settlement Day d
Cost associated with the Provision of Balancing Services to others	OM_d	£	Is the contribution on Settlement Day, d, to the value of OM_t where OM_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
Outage change allowance amount	ON	£	As defined in the Transmission Licence
BM Unit Metered Volume	QM_{ij}	MWh	As defined in the BSC
BSUoS Liable BM Unit Metered Volume	$QMBSUoS_{ij}$	MWh	QM_{ij} for all BM Units liable for BSUoS
Retail Price Index Adjustment Factor	RPIF		As defined in the Transmission Licence
Balancing services deemed costs	RT_d	£	Is the contribution on Settlement Day, d, to the value of RT_t where RT_t is determined pursuant to part 2 of Condition AA5A of the Transmission Licence
SOEMR Preparation Costs	SOEMR	£	As defined in the Transmission Licence
SOEMR Preparation Costs Adjustment	SOEMRCO	£	As defined in the Transmission Licence
Incremental change from SO Opening Base Revenue Allowance	SOMOD		As defined in the Transmission Licence

EXPRESSION	ACRONYM	Unit	Definition
SO Opening Base Revenue Allowance	SOPU		As defined in the Transmission Licence
SO-TO funding allowance	SOTOC	£	As defined in the Transmission Licence (means the SO-TO Mechanism cost allowance calculated in accordance with 4C.29 Special Condition 4J (SO-TO Mechanism))
Revenue Adjustment with respect to actual and assumed RPI values	SOTRU		As defined in the Transmission Licence
Tax Allowance	T	£	As defined in the Transmission Licence
Transmission Loss Multiplier	TLM_{ij}		As defined in the BSC
Total System Energy Imbalance Volume	$TQEI_j$	MWh	As defined in the Balancing and Settlement Code in force immediately prior to 1 April 2001
Final Reconciliation Settlement Run			As defined in the BSC
Final Reconciliation Volume Allocation Run			As defined in the BSC
Initial Settlement Run			As defined in the BSC
Initial Volume Allocation Run			As defined in the BSC
Lead Party			As defined in the BSC

12 Annex 3: CMP 281 Attendance Register

The CMP 281 Attendance register can be found here.

13 Annex 4: Paper presented to the working group by Engie

CMP281: Removal of BSUoS Charges from Energy taken from the Grid System by Storage Facilities

Summary

Storage operators currently pay BSUoS on both their import and export volume from and to the grid. CMP281 proposes to remove the liability from storage to pay BSUoS charges on imported volume. Engie has conducted an analysis of both the costs and benefits of such a measure for other market participants (particularly focused on consumers).

It is estimated that removing BSUoS from transmission connected pumped hydro imports pumping will increase overall BSUoS by on average 2p/MWh and by 5p/MWh if the increase is just applied to those paying BSUoS overnight.

Offsetting this increase, there will be a benefit in terms of lower peak traded prices as the pumped storage 'fuel' costs will be lower allowing it to generate in periods when it would have been 'out of the money' due to paying BSUoS on imports. This is estimated to save consumers around £36m giving a net benefit of around £15m. On top of this the cost of managing constraints arising from excess overnight generation can be expected to fall.

Estimated Cost Impact

If implemented, the storage sites that would become exempt from import BSUoS charges are the existing pumped storage (PS) sites (Foyers, Cruachan, Dinorwig and Ffestiniog) and existing and planned battery storage projects.

Engie has examined historic BSUoS charges to understand the impact of CMP281. In 2015 the volume of imports to PS sites totalled 3,701GWh out of a total generation and demand volume of 526,408GWh (includes only generation and demand subject to BSUOS charges). PS sites contributed £10.64m to the total BSUOS charge of £1,135m. The cost of BSUoS was £2.16/MWh (£1,135m divided by 526,408GWh) and would have been £2.17/MWh if PS had been exempt from paying BSUOS on imports (£1,135m divided by 522,707GWh). The impact on average BSUOS charges across the year would have been £0.016/MWh in 2015. Similar impacts would have occurred in 2016 and 2017 YTD (see table 1).

Table 1: BSUoS Costs/Volumes since 2015

Year	PS Imports BSUoS (£k)	PS Imports (GWh)	Total BSUOS (£k)	Total Volume (GWh)	Actual BSUoS Cost (£/MWh)	CMP281 BSUoS Cost (£/MWh)
2015	10,643	3,701	1,135,132	526,408	2.16	2.17
2016	12,247	4,002	1,219,830	522,303	2.34	2.35
2017 (H1)	6,127	2,020	601,007	254,545	2.36	2.38

The overall cost to other market participants from removing BSUoS charges on imports would have been an annualised £10.6m to £12.2m since 2015. Looking just at the impact on overnight BSUoS, the impact on other market participants between 23:00 and 07:00 would be around 5p/MWh on average.

However, additional PS demand would have occurred overnight with CMP281 in place (estimate 246.4GWh of additional pumping) which would reduce the impact on other market participants. In addition, by increasing demand in regions with excess generation (particularly during high wind/low demand periods where currently PS is uneconomic due to high BSUoS charges), the additional consumption would have contributed to alleviating constraint costs. Therefore, overall the cost of implementing CMP281 would be less than the £10.6m to £12.2m range outlined above.

Estimated Benefits

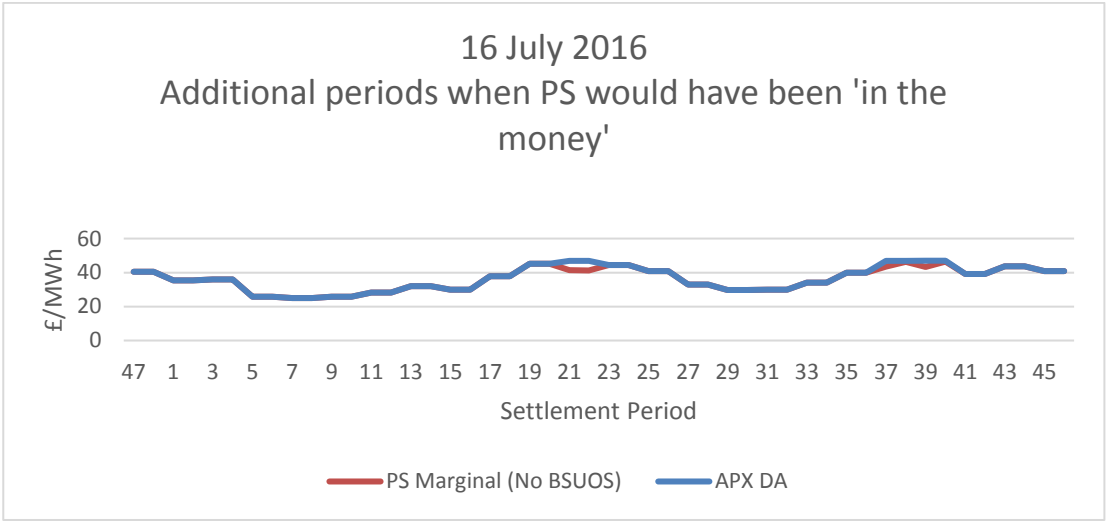
Engie has investigated the potential benefit to consumers from removing the BSUOS charge from volume imported by storage sites. The basic premise is that import BSUoS increases the price at which storage sites are able to generate during demand peaks. The result is PS generates for fewer hours each year and when it is generating at the margin sets a higher wholesale price.

The trader's BSUOS expectation would not be a flat value across a year but would be based on wind/demand forecasts and how these drive BSUOS costs. There is uncertainty about what the overall pumping cost will be but traders will make a judgement and trade to their expectation of the BSUoS cost of replacing the stored energy (potentially with a risk premium added to cover forecast error). Removing BSUOS costs mean traders will factor zero BSUOS into offer prices, which will reduce them compared to their previous expectation and lead to the lower extended peak prices.

To determine the benefit, ENGIE looked at a 12 month period from 14th July 2016. Engie calculated the cost of pumping using a simplified formula to create by adding BSUoS to the next day's APX DA auction price. Dividing by 0.75 (to represent a 75% efficient PS site) gives an estimate of the strike price at which PS sites could generate in the following demand peak.

Removing BSUoS charges from pumping costs changes the formula above to just the APX DA auction price divided by 0.75. This means the reduction in generation costs from removing BSUoS is amplified and has a greater impact on costs during peak demand periods.

To determine the impact of removing BSUoS charges from import volume, Engie compared the highest priced 8 hours clearing in the APX DA auction for extended peaks (Ext PK) to the cost of generation of PS. It is assumed for simplicity that pumping occurs overnight. The aim is to find the settlement periods where PS is marginal and where the reduction in pumping costs will reduce the wholesale price. Ranking the overnight periods and matching the lowest prices to the highest extended peak prices shows the half hours where PS is deeply in the money (no price impact) or out of the money even without paying BSUoS costs on imports (no price impact). Marginal periods are defined as ones that cleared between the cost of generation with BSUoS and the cost without BSUoS. These are the periods where CMP 281 would have an impact.



Removing BSUoS and assuming that PS generates at cost would allow PS to break even in settlement periods 19 to 23 and 37 to 40 in the example above (price data taken from 16th July 2016) where previously it would have been out of the money.

For the 12 months from 14th July 2016, the average Ext PK price (including weekends, settlement periods 15 to 46) was £50.05/MWh. Following the methodology above for PS means the average price falls to £49.92/MWh. Out-turn demand for the period examined is 198.4GWh meaning a total saving to consumers of £25.8m. The net benefit of this change is therefore around £15m.

An alternative way of looking at the benefit would be to look at the average BSUoS costs for the same period (£2.69/MWh) and apply the above methodology to again determine the periods when pumped storage would move to being in the money. The result is the benefit drops from £0.14/MWh to £0.09/MWh or £17.9m giving a net benefit of around £9m. Given that BSUoS

costs are higher overnight to manage the excess of wind on the system, using an average value is not appropriate. Whilst it can rightly be argued that traders will not have perfect foresight of BSUoS, as noted above they would make a judgement using in house analysis tools. Their judgement would produce a more relevant value than a flat assumption.

Other Benefits

One clear benefit of this reform is that it will encourage investment in new storage assets (particularly transmission connected battery storage projects) by improving the economics of such projects. As it stands there is a strong correlation between periods of high wind and low demand (when storage sites could offer a valuable service helping to manage renewable intermittency) and high BSUoS costs (often more than £10/MWh). Removing BSUoS costs from pumping improves the arbitrage potential in these periods and removes a major uncertainty.

Other benefits to the proposal include lower break even costs for providing ancillary services (particularly response services), which would translate into lower procurement costs and potential cost reductions in the Balancing Mechanism and Capacity Market.

If the modification was widened such that all transmission connected generation did not pay BSUoS when its net HH transmission connected metering was negative, the average increase in BSUoS to the remainder of the market would be around 4p/MWh over the same period. An assessment has not been made of the impact on overnight BSUoS as transmission connected generation may also be consuming during the daytime.

14 Annex 5 Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*James Anderson* *james.anderson@scottishpower.com 0141 614 3006*
Company Name:	*ScottishPower Energy Management limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*; (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the

	Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We believe that the CMP281 Original proposal will better facilitate the Applicable CUSC Objectives (ACOs). Storage facility operators are currently liable for BSUoS on both their import and export volumes (in addition to the BSUoS cost implicit in their energy purchase cost). This means that storage operators pay a higher proportion of BSUoS costs than their competitors in the provision of ancillary services. Removing demand BSUoS charges from storage will therefore better facilitate competition (ACO (a)). The Proposal is neutral against the other ACOs
2	**Do you support the proposed implementation approach?**	The Proposal should be implemented in line with the beginning of the first Charging Year following approval – preferably 1 April 2020.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com* No.

Specific questions for CMP281

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

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	As outlined in the Working Group Report, CMP281 will have a negligible impact on other BSUoS payers. Removing the £12m of BSUoS paid by storage facilities in prior charging years would have increased the average BSUoS charge to others by around £0.02/MWh (0.8%) which is well within the level of forecasting accuracy. As currently drafted, Generation Licence holders will require to satisfy themselves that supply taken at their generation premises are solely associated with the generation activities and certify this to National Grid's BSUoS billing team. As a one-off exercise which relieves the Generation Licence holder of liability for demand BSUoS this should not prove too onerous.
6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	Yes. As outlined in the Working Group Report Section 4.1, CMP281 delivers the change proposed in the Government and Ofgem's Smart Systems and Flexibility Plan (July 2017) and is in line with the direction of travel of Ofgem's work on the TCR/SCR dealing with recovery of residual charges from demand. The analysis within the Workgroup Report indicates that there is currently no effective signal provided by demand BSUoS charges. Removal of demand BSUoS would therefore not be detrimental to operation of the transmission system or to consumers. Should a more cost reflective method of recovering BSUoS costs which provides a effective signal be developed under the TCR/SCR then this can be defined and implemented following implementation of CMP281.

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Paul Youngman* *Paul.Youngman@drax.com* *01757 612757*
Company Name:	*Drax Power Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*;

	(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes, we believe that the Original Proposal (removing BSUoS liability on imports from all facilitates supplied under a generation licence) better facilitates the Applicable CUSC Objectives. **Applicable CUSC Charging Objective (a) – Positive** In addition to the BSUoS costs implicit in their 'fuel cost', currently storage providers pay BSUoS on both their import and export volumes. Storage providers are therefore contributing disproportionally towards the cost of balancing the system compared to other generation technologies. This is distorting competition. The removal of BSUoS liability on imports from all generation facilities supplied under a generation licence is a simple and effective solution that will address the defect and better facilitate effective competition in the generation of electricity. Ultimately reducing costs for the end consumer. When the proposal was first raised the solution applied only to imports to storage facilities, this was then amended so the original proposal now includes all facilities supplied under a generation licence. Our preference is for this approach which: • Levels the playing field by correcting the defect related to storage whilst not introducing any other distortions between different technology types • Should be relatively easy to implement at least cost to the consumer
2	**Do you support the proposed implementation approach?**	We support implementing CMP281 on the 1st April 2019 to coincide with the start of the Charging Year. If implementation cannot be achieved for the 1st April 2019, CMP281 should be implemented as soon as possible thereafter.

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

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	We believe the main impacts have been captured in the proposal and consultation.
6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	In our view the current proposal has a positive impact on competition and levels the playing field between different types of generation. We believe this is in line with Ofgem intent and the objective of the Smart Systems and Flexibility Plan.

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Nicola Percival* *nicola.percival@innogy.com* *07557 758 382*
Company Name:	*Innogy Renewables UK Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*;

	(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No. innogy does not see that the implementation of CMP281 would better facilitate any of the CUSC objectives. If implemented this modification would positively discriminate to benefit only licenced storage connected to the transmission network, of which only pumped storage is currently identifiable as 'storage' in the generation licence. There were two DCUSA change proposals looking to remove residual charges from storage/embedded generation – DCP319 and DCP321. These were broadly the DCUSA's version of CMP280 and CMP281. We note that the DCUSA proposals have both had proposer support withdrawn, this coming swiftly after a direction from Ofgem that CMP280, DCP319 and DCP321 should apply to storage only and not all generation. The reason for the withdrawal of support is that the proposer felt that removing residual charging for storage only (not generation more broadly) would create a distortion between storage and all other embedded generation. No workgroup members for DCP319/321 chose to support these proposals or raise alternatives following Ofgem's letter and the proposer's withdrawal of support. Innogy feels that the proposer of CMP281 (and CMP280) should follow suit given that this modification will create a similar distortion[1]. Ofgem have made it clear that they "*reserve the option, if necessary, of bringing storage charges back into the TCR SCR…*"[2]. Innogy encourages Ofgem to do so. Innogy are supportive of proposals which would level the playing field for all types of network users across both transmission and distribution networks. However CMP281 does not do this. The identified defect is indicative of a much deeper set of issues related to broader policy (eg the Smart Systems Plan, BSUoS PSO), which is much wider than just the CUSC and DCUSA. It is important that the workgroup, and especially Ofgem, considers CMP281 in the context of the withdrawn DCUSA modifications as well as other CUSC change proposals looking at reforming the current structure of BSUoS e.g. CMP308 and the TCR SCR and upcoming SCR.
2	**Do you support the proposed implementation approach?**	We do not support the modification, and so we do not support the implementation approach either.

[1] Which is referred to by the proposer on page 13, and elsewhere, in the workgroup consultation. The report is contradictory in places, which has likely created confusion for some respondents.

[2] Ofgem Targeted Charging Review Significant Code Review launch letter, 4th August 2017

Q	Question	Response
3	**Do you have any other comments?**	It is important that network charges do not prevent a level playing field between different providers of flexibility. Any future review on BSUoS looking into its cost reflectivity / who should pay BSUoS would affect all parties within the energy system, regardless of where on the network they connect. Changes to charging for storage should be part of this wider review of BSUoS charging rather than being taken through the piecemeal code governance process, particularly where piecemeal changes would create further distortion. This will allow for a whole system treatment of storage across both transmission and distribution and ensure those facilities have been treated fairly alongside other forms of generation. In addition, we note that in all four of the FES scenarios from 2018 pumped storage is assumed not to contribute many more TWh than today: "*Very little opportunity for new pumped storage sites that haven't already been developed*"[3] and transmission-connected storage of any kind is not expected to increase much by 2030. On page 14 of the workgroup consultation the Proposer refers to FES data that between 7GW and 10GW of storage would be connected to the grid by 2030. The statement is correct but this accounts for all types of storage, connected at both transmission and distribution. The estimation of the impacts of CMP281, should it be implemented, appears to have been calculated based on historic data, but the inference that this could become more significant over time is flawed and misleading. Innogy are also concerned about the wording used in the Smart Systems and Flexibility Plan: Progress Update. In Annex A, action 1.1, under 'What we will do next' it states: *"Industry will finalise charging code modifications to address the storage issues identified in the Plan, and it is expected that these will be submitted promptly to Ofgem for approval."* This suggests that Ofgem is predisposed to approve the modifications CMP280 and CMP281 before the workgroup and consultation phases are finalised.

[3] Data Workbook http://fes.nationalgrid.com/fes-document/

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

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	
6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	No. CMP281 would create new distortion rather than levelling the playing field. The workgroup discussions have been eye-opening in discovering the complexity and interlinkedness of these modifications with broader policy (eg the Smart Systems Plan, BSUoS PSO) and, in innogy's view, have shown that a standalone CUSC Mod is an inappropriate way to explore further how the playing field can truly be levelled. These issues are better suited to a more formal review, which is **not** a priority over the current TCR and upcoming SCR. Please refer to our answers to Questions 1 and 3 for full detail.

CUSC Workgroup Consultation Response Proforma

CMP81 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	No. We do not think competition is better served by the proposal because it does not resolve any differences between CVA and SVA. We can see that this modification does to some extent level the playing field between transmission connected storage and generation on the basis that storage will import comparatively more than conventional generation and to that extent we are not so opposed to it. However, we note that the proposal does not really address the stated defect and is encroaching on the remit of Ofgem's TCR.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No. We do not think competition is better served by the proposal because it does not resolve any differences between CVA and SVA. The rationale given for not extending the proposal to SVA as presented on page 13 of the consultation document is specious; a supplier may be charged BSUoS on a net basis, but the demand and generation that make up the supplier's net position are settled by them discretely on the gross impact they have on that net position.
2	**Do you support the proposed implementation approach?**	No. We are opposed to this. The document states the following: *Any implementation date is dependent on gaining a decision from The Authority in the August before the start of a Charging year. Therefore, we would need a decision from the Authority by August 2019 to be able to implement this modification for April 2020.* This suggests a mere eight months' notice. Traditionally, pricing modification proposals of this nature have had a longer lead time.
3	**Do you have any other comments?**	Please see answer to Q6
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	We do not envisage that there will be much of an impact on billing operations.

6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	Page 8 of the consultation document states the following: *The proposed solution under the CMP281 modification was discussed in the context of the legislative framework outlined above. The proposal as originally defined required separate identification of storage facilities reflecting the proposed definition of storage under the new form of Generation Licence. In the context of the activities permissible under the Electricity Act and the generation licence it became clear the such detailed provisions may not be required as part of the CMP281 solution. Consequently the CMP281 proposal was refined. It is now based on the removal of "off taking" BSUoS charges from all generation facilities operated under a generation licence*. The defect, however, was defined as follows: *Under the current Charging Methodology, storage providers pay BSUoS on both their import and export volumes (in addition to the BSUoS costs implicit in their 'fuel cost'). Storage providers are therefore contributing more towards the cost of balancing the system than other users. Storage providers, who compete with generators in the provision of ancillary services, are therefore at a competitive disadvantage, which is likely to distort market outcomes and so disadvantage consumers.* Ironically, therefore, the "refined" proposal reduces charges for generation and storage but does not completely level the playing field between generation and storage as far as charging is concerned, save for the fact that storage would generally have greater levels of import. More generally, the original proposal probably is moving towards Ofgem's and Govt's intentions with regards to placing network costs on demand. However, we are inclined to think that the "refined" proposal jumps the gun of the TCR. Ofgem recommended in the Targeted Charging Review consultation that changes to charging for storage should be taken forward ahead of any wider changes to residual charging. This proposed solution does not fulfil that requirement.

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Respondent:	*Binoy Dharsi (binoy.dharsi@edfenergy.com)*
Company Name:	*EDF Energy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*; (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity

	Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Ofgem state in their TCR consultation (published 13th March 2017 paragraph 1.31) *"We think that the way charges affect storage at present create a relative disadvantage for storage operators, in comparison with generators connected at the same voltage level"…." This is because…transmission-connected storage pays BSUoS as both demand and generation. In order to secure a more level playing-field, we think that storage should be liable to pay only….one set of BSUoS charges."* Given Ofgem's statement in the above cited extract we believe that the Original Proposal delivers an appropriate solution.
2	**Do you support the proposed implementation approach?**	Yes.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	We do not believe there will be any issues (beyond business as usual) in relation to tariff stability. The impact is on a very small percentage of the entire BSUoS cost. We do not foresee any significant impact on operations, billing or processes in the implementation of the Original proposal.

6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	Yes. We believe the proposal solution will ensure that competition between generators and storage assets at the same voltage level will be on a fairer basis.

CUSC Workgroup Consultation Response Proforma

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Respondent:	*Yonna Vitanova* *+44 (0)20 7901 3000. Yonna.Vitanova@RenewableUK.com*
Company Name:	*RenewableUK* *https://www.renewableuk.com/*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*;

	(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response

1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No, we do not believe that CMP281 original proposal or any of the identified alternatives would better facilitate the Applicable CUSC Objectives. We are concerned that if implemented the modification would not improve competition between supply and generation of electricity, but it would create a benefit for only one type of generation (large pump hydro). The consultation document relies on National Grid Future Energy Scenarios (FES) data suggesting that between 7GW and 10GW of storage would be connected to the grid by 2030, however this accounts for both transmission and distribution connected storage. In fact, the latest FES document predicts transmission connected storage capacity to be comprised up of 4TWh pumped hydro facilities and less than 1TWh battery storage by 2030 in its Community Renewables scenario. This does not present a significant growth from today. Indeed, the consultation itself relies on analysis showing that the pumping volume was approximately 4TWh in 2026/17, representing 0.78% of the total volume (520TWh) liable for BSUoS charges. We are particularly concerned that such misinterpretation would not lead to accurate estimation within the impact assessment of the change proposal and needs to be revised before any further analysis is carried out. Removing BSUoS charging from imports for transmission connected storage is particularly discriminatory against embedded storage facilities with the latter still subject to residual elements of EDCM and CDCM distribution charges. We would like to note that DCP319 and DCP321 change proposals looking to remove residual charges from storage/embedded generation have been withdrawn from DCUSA recently with no alternative being raised. In this context implementing the solution under CMP281 would create a significant distortion in the way storage is treated across transmission and distribution and in itself benefit transmission connected storage facilities only. While we are supportive of the proposals which aim to encourage a level playing field between different providers of flexibility we believe that distributed storage should be treated no differently. Currently there is no alternative proposal which would ensure equal treatment of storage across both transmission and distribution. CMP281 would also have cross-code impacts which have not been considered so far. Thus, it is also important to consider the proposal in the context of these DCUSA modifications as well as other CUSC change proposals looking at reforming the current structure of BSUoS e.g. CMP308. We are mindful that a wider review of BSUoS charging methodology is likely to be raised later on this year separately

Q	Question	Response
		from the Targeted Charging Review Significant Code Review and Ofgem work under Access and Forward-looking charges. As BSUoS charges are not split into residual and forward-looking elements in the same way as TNUoS and DUoS, such wider review would look at whether certain elements of this charge can be isolated and removed to ensure cost reflectivity. Appropriate charging for storage should be part of a wider review on BSUoS to ensure a wholistic overview of the issues across generation and demand.
2	**Do you support the proposed implementation approach?**	No, we do not support the proposed implementation approach as this will unduly favour only one set of generation (large pump hydro).
3	**Do you have any other comments?**	It is important that network charges do not prevent a level playing field between different providers of flexibility. We are concerned that any future review on BSUoS looking into its cost reflectivity would affect all parties within the energy system, including storage providers. Changes to storage charging should be part of a wider review of BSUoS charge rather than being taken through the piecemeal code governance process. This will allow for a whole system treatment of storage across both transmission and distribution and ensure those facilities have been treated fairly alongside other forms of generation.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	

6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	Please refer to our answer to Q1.

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **12 November 2018** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Andrew Colley andrew.colley@sse.com*
Company Name:	*SSE plc*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*; (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity

	Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes. SSE agrees that the current BSUoS charging regime requires storage providers to contribute more towards the cost of balancing the system than other users, leaving them at a competitive disadvantage when compared to other flexibility providers. Perpetuation of this distortion could hinder the development of new storage projects to help provide flexibility options for the Total System. Electricity storage facilities import electricity from the Transmission System in order to store it for reinjection at an appropriate time to be used by end consumers. The storage facility does not have self-consumption as its primary purpose. The current charging regime therefore can result in double counting of energy to the end consumer - when imported by the storage facility (and considered to be self-consumption); and when exported and recorded as consumption by end consumers. This adds to the costs of operation of storage, resulting in a competitive distortion which may also result in additional costs being passed through to end consumers. SSE believes that the proposal will remove a distortion in competition between different types of energy producers, ensuring that certain users do not pay disproportionate costs, resulting in a fairer allocation of costs and thereby better facilitating applicable objective a)
2	**Do you support the proposed implementation approach?**	Yes

Q	Question	Response
3	**Do you have any other comments?**	SSE support the criteria proposed by the workgroup to determine the scope of Parties that should receive relief against the import charge, i.e. supplies associated with licensed generation activities (including storage). We believe that this greatly simplifies the solution and that it is consistent with the current direction of travel to equitably recover revenue from end-use consumption and ensure a level playing field for flexibility providers. However, we would not want to delay progress of the modification as a result of it being subsumed within the current charging SCR (by virtue of the wider coverage of licensed generators that would benefit). If the workgroup considers this a realistic risk, then SSE would support an alternative that reflects the Original Proposal (i.e. limited to CVA storage facilities) to address the current disadvantage for storage operators, as opposed to the Amended Original.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	The main impact for CUSC Parties will be a redistribution of costs as liabilities are removed from licensed storage and generation providers. SSE do not consider the estimated impact of this redistribution (as detailed in Chapter 14 at approx. 2p per MWh) to be significant. It will reduce the operating costs of storage facilities in particular, allowing them to compete on a more level playing field with other flexibility providers to the ultimate benefit of consumers. SSE currently operate a Transmission connected storage facility so would expect to change cost modelling and back-office systems to reflect the revised charging arrangement if approved. We estimate that our systems and process costs would be relatively small however, with the majority of the impact falling upon National Grid ESO's and ELEXON's processes and systems.

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

6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	Yes.

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Respondent:	Urmi Mistry Urmi.mistry@nationalgrid.com 07814792971
Company Name:	National Grid Electricity System Operator (NGESO)
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*;

	(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response

1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We believe the proposed original (applicable to storage only) and the amended solution (applicable to all generation) creates some unintended consequences and so does not better facilitate the applicable CUSC objectives: • Objective (a) – This modification will have a negative impact on this objective. Regarding the original proposal of storage only, it is discriminatory in nature. Storage will be exposed to less use of system costs than other forms of generation creating a market distortion potentially limiting competition. Where the modification solution is applicable to all generation, this has a marginally less negative impact on this objective. This solution may also conflict with the outcomes of Ofgem's Significant Code Review (SCR) into residual charging and as such it is difficult to assess whether it is appropriate to take this proposal forward at this time. • Objective (b) – As it currently stands this modification will have a negative impact on this objective because it would cause a breach of Transmission Licence Condition C26. This condition states that 'The licensee shall use all reasonable endeavours to ensure that in its application of the use of system charging methodology in accordance with standard condition C5 (Use of system charging methodology), use of system charges resulting from transmission constraints costs are treated by the licensee such that the effect of their recovery is shared on an equal per MWh basis by all parties liable for use of system charges' (as stated on page 22 of the consultation document). This modification would cause BSUoS liable parties (generators and suppliers) to pay unequal amounts as only a portion of BSUoS costs are removed from liable parties. Therefore, if this modification were approved this would cause a breach of licence for the transmission owner. To avoid this occurring the licence condition would need to be updated. • Objective (c) – neutral • Objective (d) – neutral • Objective (e) – There will be a negative impact on this objective. If the proposal is implemented as suggested/discussed by the workgroup so far, it will introduce complexity in administration and implementation of the CUSC. The proposed process suggested on page 8 of the report, is that National Grid are notified of which BMUs are owned by a Licence holder and then the exemption is applied by National Grid to these units. This process at a high level would

Q	Question	Response
		require significant changes to IT systems resulting in substantial implementation costs. This process would involve a new system to; o maintain a register of relevant generators/BMUs, o quality assure the data in the register, o synchronise the register with Elexon's Central Registration Agency, o interface and provide data to existing systems from the register, e.g. daily submissions of data to the Charging and Billing (CAB) system and so a new input source and consequential changes to internal systems. New processes will also need to be established to support the new system such as dispute, data error assurance and data correction. This would replicate a process already carried out by Elexon during the BMU registration process. Therefore, the workgroup should consider this when looking at implementation as this would be the more efficient option and have the lowest overall cost to the consumer.
2	**Do you support the proposed implementation approach?**	If this modification is approved, we would support the approach detailed on page 15 of the consultation document ('Implementation Information') and in section 7. This would only be practical if there was an Authority decision in the July/August before the start of a Charging Year. If a decision is received later than July/August 2019 then implementation should be no earlier than April 2021, owing to the significant system changes required to facilitate this CMP.

3	**Do you have any other comments?**	We have a few comments for the workgroup to consider: 1. Further considerations for the Workgroup: We feel that the fundamental issue is with the BSUoS charging methodology, its principles and how it is calculated; therefore, this needs to be considered and is vitally important to this modification. The defect and issues analysed by the workgroup highlight the fact that the current BSUoS methodology is not appropriate for the electricity system of today. This is highlighted within the 'wider defect' section, on page 11 of the consultation document, which mentions the counter intuitive nature of BSUoS where behaviour by parties which is beneficial for the network, is penalised. This is another fundamental question which needs further consideration as this modification will only redistribute the cost incurred in any one settlement period to a smaller number of parties and so exacerbate the wider defect. In October NGESO ran a series of Workshops to start a wider piece of work to consider BSUoS in more detail and begin a larger reform of the BSUoS charge. We feel this is a better route to address the questions surrounding treatment of storage in a more holistic and non-discriminatory manner. There is also a significant amount of industry work underway that will materially affect the direction of this modification and BSUoS, such as the TCR SCR, Access & Forward Looking Charges reform and the Storage Licence Consultation (which is still awaiting decision from November 2017). All of these things will impact the BSUoS methodology fundamentally and so any solutions proposed as part of this modification may become redundant in the future or create larger distortions as results from these larger pieces of work become clear. The CUSC modification process dictates that the baseline is used to assess proposals against, however this modification overlaps with other work-streams which aim to make a fundamental change to current arrangements. So, to ensure the solution is future-proof and fit for purpose, these areas of work need to be considered within the solution. Additionally, NGESO are not allowed, under our Licence, to unduly discriminate between any persons, class or classes of persons (Licence Condition C7 'Prohibition on discriminating between users'). There has been no clear direction from Ofgem that Storage should be treated uniquely from any other form of generation, this is also not reflected or evidenced in the report strongly enough. Therefore, by applying BSUoS to a certain group of industry parties mainly based on differing

		business costs (fuel cost in proposal form) cannot be used as a strong enough reason to discriminate. There is currently a storage licence consultation which is with Ofgem for decision. This consultation looks to introduce regulatory arrangements for storage into the Generation Licence. This closed in November 2017 and is still awaiting a decision. This further adds to the argument that Storage is no different from any other form of generation. If the proposal goes ahead with the updated solution covering all generation, there will be discrimination between transmission connected and embedded generation and between generation and demand/supply parties. Therefore, this should be considered further. The current direction of travel of CMP281 uses the Licence as a basis to identify those parties who are liable for BSUoS and those who aren't. The Licence refers to a legal entity rather than a specific generating station or BMU. Therefore, this will be complex to implement for the BSUoS methodology as currently BSUoS is calculated on a Trading Unit/BMU basis. There has been no clear way for NGESO to be able to use this information to clearly identify these units without significant costs incurred and inefficient processes introduced. This process of identifying the exemptible parties needs further consideration. Another aspect that is mentioned on page 21 of the report is the Public Service Obligation (PSO), which states that costs are spread equally across parties and links to the Transmission Licence Condition C26 (applicable CUSC objective (b)). The PSO is something that needs to be considered further by the workgroup and steps should put in place to address it. If this is not done before this modification is implemented, then NGESO will be in breach of its Licence Another area to consider is that Ofgem published their decision on CMP250 on the 25th October 2018. Ofgem rejected this modification but made suggestions on further work regarding BSUoS, such as future assessment of the components of BSUoS and evaluating their impact, whether they are cost recovery/cost reflectivity and consideration of impacts wider than the CUSC e.g. licence impacts. Therefore, it would be prudent to ensure these areas are considered and clear within the report to give Ofgem as much information as possible as to whether this modification will have an impact on the components of BSUoS.

Q	Question	Response
		Modification GC0096 is referenced in the consultation document on page 17 which looks to introduce technical requirement for Storage. This Grid Code modification has moved on since this section was written and poses some questions which need consideration: o The proposed definition of 'Electricity Storage Facility' excludes Pumped Storage. This is a concern as it creates a new category on the same level as Power Station and so this will need to be reflected in the CUSC. To keep definition consistent across codes, this exclusion of Pumped Storage would mean that any solution created under CMP281 and assuming the definitions aligned with the Grid Code, the Pumped Storage stations defined in the Grid Code will still be liable for use of system charges. Therefore, the addition of 'Electricity Storage Facility and Pumped Storage' should solve this issue within the CUSC. We encourage the proposer and any proposers of alternatives to ensure this is captured within their solution. 2. General Comments The figures presented in the report looking at material impact of this modification, consumer impact and impact on RCRC (residual cashflow reallocation cashflow) do not consider the future network and the predicted increase from 3GW of storage on the system to between 7GW and 10GW by 2030. Therefore, the numbers presented in the report do not provide any future estimation of the impact of this modification (Annex 2, impact on consumers and materiality sections) therefore it is hard to understand the impacts of this modification, true cost to industry parties and to the end consumer fully. This modification, at present, doesn't have a clear solution or clear understanding of how this will be implemented, therefore this needs to be fully considered by the workgroup and noted so it is clear to Ofgem and industry. We are of the view that a much broader reform of the BSUoS methodology is needed, it will have longer term benefits and be more valuable for all industry parties and consumers. It will also create a charging arrangement that is fit for purpose, clear and transparent.

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	Not at this point in time. However, it should be noted that DCUSA modification DCP319 and DCP321 are being narrowed in scope following a letter from Ofgem. Both look to address the same issues as CMP280 and CMP281 but on the distribution network. This should be noted as this modification may receive the same direction from Ofgem, following the increase in scope to all generation. Also, that if CMP281 were approved it will create a further distortion between the transmission and distribution charging arrangements if these DCUSA modifications are not also approved.

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	Impact on NGESO: • We have detailed the high-level system changes required for NGESO in the System changes section of consultation document (page 15 of the report). • How we identify these units is not clear from the consultation document and needs to be fully considered. It may be that Elexon would be more easily able to identify these sites and therefore a consequential BSC modification would be necessary to ensure data is provided to the ESO at lowest cost overall to the end consumer.

6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	In our view, the original proposal will not level the playing field in the way that Government and Ofgem intended in recent publications. It would be prudent to wait for more information to be published by Ofgem on the TCR SCR before this modification goes any further. • In July 2017 Ofgem & BEIS published 'Upgrading our Energy System – Smart Systems and Flexibility Plan'. In this document, they stated 'These views are that storage facilities should not pay the 'demand residual' element of network charges at transmission and distribution level, and that storage providers should only pay one set of balancing system charges.' Therefore, this modification would be fulfilling this intention as indicated by Ofgem & BEIS. • However, the modification does not consider the update in Ofgem's position and the possibility of a forward-looking element (if found). Following Ofgem's Storage Charging Summary note (Feb 2018) publication (as noted in the consultation document), storage should pay forward-looking charges on both import and export. This modification, at present, will not facilitate this. If a forward-looking element is found within BSUoS, under this modification storage (and possibly all generation) will pay no form of BSUoS on their imports at all. As the solution is not clear for this modification, it could result in multiple changes being needed in the future (change upon change etc…) which will reduce certainty in the market and impact competition. • The proposal also does not consider Ofgem's work on the TCR SCR or Access & Forward Looking charges fully. They are looking at residual charges and suggest wider areas of BSUoS need to be looked at. This work will have a knock-on impact to this change proposal. Aligning with this work will ensure that arrangements put in place for generation will be equivalent with arrangements for storage parties. • This modification doesn't address BSUoS embedded benefits issue. Ofgem have noted that other embedded benefits will be kept under review and so waiting for further direction from Ofgem on how this will be addressed will be beneficial for this modification when looking to create a solution.

PaulCUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Paul Jones* paul.jones@uniper.energy
Company Name:	*Uniper UK Limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*; (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the

	Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	Yes, subject to clarification of some points we raise in our response to 3 below. It should facilitate objective a) by promoting competition in the wholesale market.
2	**Do you support the proposed implementation approach?**	Yes.

Q	Question	Response
3	**Do you have any other comments?**	There seems to be some confusion about the exact solution being proposed in the text. Section 3 on page 6 of the consultation says that section 14.29.4 will be changed to prevent all off-taking Exemptible Storage BMUs from being charged BSUoS. However, section 19 on page 23 implies that all off-taking BMUs and Trading Units associated with generation operating under a generation licence will be exempt, which seems to be in keeping with other text in the consultation. Our support above is made assuming this latter interpretation. In the text in section 19, reference is made to Demand BMUs. However, this does not seem to be defined anywhere. The text will presumably need to be tidied up generally. For instance, it currently refers to supply "under a Generation licence" which seems to imply that a generation licence directly authorises you to supply when it is the provisions of the Electricity Act which allows this to happen under an exemption. A number of power stations are charged on a Trading Unit basis, so that station demand is netted from any generation at the same station. We assume that the wording in section 19 is aimed at allowing this to continue. Therefore, it is only when the Trading Unit becomes negative, due to station demand being higher than any output during the period, that the charge becomes zero. Accepting that it is always preferable to keep legal text simple, it's not clear from the present drafting that this is indeed the case. The implementation costs for the modification seem quite high. It may be worth exploring whether costs could be reduced by making the changes to systems and processes required for this modification at the same time as any needed under Ofgem's charging review.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No thank you.*

Specific questions for CMP281

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	We do not anticipate a significant implementation issue for ourselves. It is possible that there may be contracts which could be affected, but presumably these will have appropriate regulatory reopener clauses.
6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	It would seem to. A modification which solely looked at removing the charge from storage, but did not introduce equivalent treatment for generation, would have introduced another form of discriminatory treatment.

CUSC Workgroup Consultation Response Proforma

CMP81 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

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Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

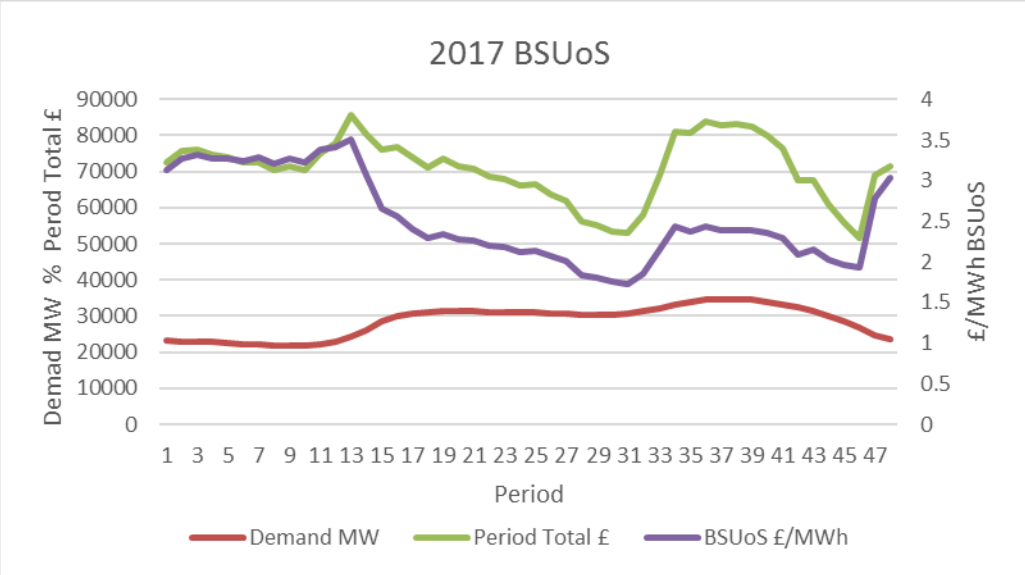
These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to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

Respondent:	*Libby Glazebrook* *Libby.glazebrook@engie.com*
Company Name:	*ENGIE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** **…….** .

Standard Workgroup consultation

1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	**Background** The current methodology of collecting BSUoS from storage demand is leading to increased customer costs. We believe that the proposal to only charge demand BSUoS to end consumption or ENGIE's alternative which does not charge BSUoS on CVA storage imports will deliver customer benefits and improve the efficiency of the current power market in the despatch and scheduling of generation to meet demand. Appendix 1 (attached) details analysis provided by ENGIE to the working group that sets out the issue and the cost savings associated with changes to the current arrangements if applies to CVA storage. CMP 281 was raised in July 2017 and the report demonstrates the issue has been examined by the group and that the group has a good understanding of the range of possible solutions. We believe that it is now time for the group to move forward in a timely fashion with a solution (or solutions) that can be presented to the Authority. **Economic rationale for only charging end consumption** Academic literature (e.g Diamond-Mirrlees et al) on production efficiency recognised that the most efficient way to collect fixed revenue (e.g BSUoS) is to apply it only to end consumption. An example of this is rail and postal services that are not subject to VAT. A simple assumption for VAT collection could be that it will be possible to raise more VAT if it is applied to postage and rail costs. This assumption is incorrect - it is optimal to have no distortions in production of goods based on recovering fixed (tax like) costs. Businesses that use postage will simply apply the additional VAT plus their processing expenses (inefficiency cost) and apply this cost to the cost of goods and services which are passed on to the end consumer. In addition, competition between business will be improved if they can compete on the basis of their business designs and production costs that do not include tax-like charges. A more efficient outcome is to recover the same (higher) amount of VAT directly from consumers. Since the cost of the additional inefficiency does not need to be collected, costs will be lower and competition between business will result in a more efficient outcome, based on their business designs rather than the application of a tax-like charge. The application of BSUoS is similar - it should not distort production decisions and leads to the ultimate conclusion that BSUoS should be applied only to end consumption. Although BSUoS is a half-hourly charge, most of the individual elements relate to actions that are required across multiple time periods with the magnitude determined principally by the demand shape. At all points in the day generation and demand must match so actions in one time period cannot be divorced for those in other time periods. In reality, although the cost (£m) may be flat across the day, this will drive a high BSUoS price at low demand periods. The shape of BSUoS (£/MWh) is simple a cost recovery across a varying number of consumers, exacerbating the current distortion. ***Economic rational for not applying BSUoS to storage imports*** The chart below shows for 2017 the average period daily cost of BSUoS (green line), average period demand (red line) as well as the demand. £/MWh charge (purple line). As can be seen the period costs allocated overnight and over the system peak are similar but the resulting £/MWh change is far from

flat. Driven principally by demand and the need to ensure sufficient head- and foot-room during lower demand periods, the overnight rate is roughly 1.5 times the daytime rate. This is driven by the methodology which recovers a similar period amount over lower demand periods.



This effect leads to higher daytime wholesale prices as storage is subject higher levels of BSUoS on its imports. Appendix 1 details analysis by ENGIE that explores this more with a real world example based on the use of storage on the transmission system.

The current arrangements and three possible solutions

The working group report identifies a number of possible solutions to the issue raised by the proposer and sets out the current position. We have simplified these and put them in table form below broken down into three scenarios based on affected groups:

Current position BSUoS liability	A	B	C
	Transmission Storage	Transmission Generation Demand	Embedded Storage and generation
Demand BSUoS	Pays	Pays	Pays
Generation BSUoS	Pays	Pays	Receives

The efficient positions from a customer's perspective are shown below:

Possible Solution BSUoS liability	A	B	C
	Transmission Storage	Transmission Generation demand	Embedded Storage and generation demand
Demand BSUoS	Exempt	Exempt	Exempt
Generation BSUoS	Pays	Pays	Pays

For each scenario we suggest how the working group should address further work, potentially proposing two solutions to the Authority based on scenarios A and B.

A The narrow scope simple solution

The simple solution exempts transmission-connected storage and embedded storage over 100MW from liability for demand BSUoS and hence improves the cost reflectivity of the system. The group has struggled to arrive at a definition of this type of storage as a storage class within the generation licence is not in place yet. This is why the group moved to the wider solution that applies to all transmission connected generation.

There are currently four transmission connected pumped storage facilities and one transmission connected battery storage facility. Whilst it should be easy to identify these, in practice, in the absence a storage class within the generation licence it has proved difficult for the group to come to a solution and, as such, a definition has not been developed.

We put forward the following solution to the narrow scope simple solution and have raised this as a consultation alternative:
==========
A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):

All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Storage BMUs shall be disregarded.

For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology –

An Exemptible Storage BMU is a BMU that :

is listed in Appendix C of a bilateral connection agreement (BCA) that is associated with an electricity storage facility as set out in the Generation Licence;

or

is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptable Large power station Agreement (BELLA) above 100MW in size and are associated with an electricity storage facility as set out in the Generation Licence;

or

the Authority has directed that the BMU is an Exemptible Storage BMU for the purposes of the CUSC.

Part (a) of definition is designed to only cover transmission-connected storage as only this type of storage has a BCA and will be active once the definition of storage in included in the generation licence. We do not believe that any BEGA or BELLA storage facilities exist but have put the definition (b) in for completeness. Again this is only active once a storage licence is in place.

Part (c) allows an Exemptible Storage BMU to be identified prior to a licence definition being in place with the Authority issuing a notice to National Grid. The Authority would issue a notice identifying for the storage facility, all the BMU's listed in Appendix C of the storage facility bilateral connection agreement (BCA). The BCA details the BMU's that are included in the power station/trading site.

Part C flow chart is contained in Appendix 2

An example of a BCA for a storage facility is shown below.

NATIONAL GRID COMPANY plc

and

FIRST HYDRO COMPANY

AGREEMENT TO VARY THE
BILATERAL CONNECTION AGREEMENT
FOR FFESTINIOG

Appendix C

Connection Entry Capacity and Transmission Entry Capacity

Company: First Hydro Company

Connection Site: Ffestiniog

Part 1 Connection Entry Capacity

Connection Entry Capacity Expressed as an instantaneous MW figure

Part 2 Transmission Entry Capacity

Transmission Entry Capacity (TEC) expressed in average MW taken over a half-hour settlement period

Part 3 BM Units Comprising Power Station

T_FFES-1	(Associated with FFES_01Z)
T_FFES-2	(Associated with FFES_02Z)
T_FFES-3	(Associated with FFES_03Z)
T_FFES-4	(Associated with FFES_04Z)
T_FFES-ST1	(Station Demand)

Using this methodology, the Authority could issue notices for all transmission-connected storage facilities to National Grid.

B The wider scope solution to include transmission generation demand

Whilst the simple solution improves cost reflectivity of the system by exempting transmission-connected storage demand from BSUoS liability, there would be some additional benefit to the wider system by exempting all transmission connected demand used for generation from BSUoS liability. The effects detailed in Appendix 1 would incrementally less than those from storage demand but would still give additional consumer benefit.

Again we believe that a simple solution should be adopted for this methodology by the group and example text is shown below. This is the same as the new original modification proposal.

==========
A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):

All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period,except that energy taken from the system by Exemptible Demand BMUs shall be disregarded.

For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology –

An Exemptible Demand BMU is a BMU that :

is listed in Appendix C of a bilateral connection agreement (BCA) that is associated with a Generation Licence;
or

is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptible Large power station Agreement (BELLA) above 100MW in size and associated with a Generation Licence;

This definition would not be dependent on a storage licence and would apply to all transmission connected demand associated with generation.

C The complete transmission and distribution solution

Whilst we would support the inclusion of embedded storage facilities in a solution, the development of a solution requires significant changes to the current embedded benefits methodology for all embedded generation to ensure that embedded storage is treated the same as transmission storage.

Currently embedded storage is roughly neutral to BSUoS as it pays on demand and receives on generation, so it is not as pressing an issue for this type of storage as it is for transmission connected storage.

ENGIE raised CMP307 “Expanding the BSUoS charging base to include embedded generation” to start the process of addressing the embedded

Standard Workgroup consultation		
		benefits issue". Following this. the Authority has indicated that embedded benefits are being reviewed as part of the current TCR SCR and has decided to not allow the progression of CMP 307. We believe that there is little point in the group developing a solution for embedded storage (CVA below 100 MW and SVA) without dealing with the wider BSUoS embedded benefits issue which is now being dealt with by Ofgem as part of the TCR SCR.
2	**Do you support the proposed implementation approach?**	Yes although this is not clearly set out in the consultation. We believe that National Grid as ESO will need to identify the best way to implement the solution. This could be achieved by it "flagging" units that are not charged BSUoS as part of its systems. Alternatively, if the ESO believe that this flagging process is best achieved in the BSC than we would expect National Grid ESO to raise an appropriate modification.

Standard Workgroup consultation		
3	**Do you have any other comments?**	CMP 281 was originally raised to remove the BSUoS charge from transmission connected storage imports and thus ensure that this type of storage only pays one set of balancing charges. This could also be achieved through the revised Original proposal (which applies to all licenced generation – limited to those with a BCA (and BELLA/ BEGA over 100 MW). ENGIE would support either of these changes. Ofgem set out proposals in their 'Smart System and Flexibility Plan' to reduce BSUoS charges for storage and reiterated these concerns in their November 2017 TCR update. To address Ofgem's specific concern, CMP 281 should have storage only solution as well as the wider solution. We do however note that National Grid estimated costs of between £0.5 and £1m to deliver to storage only solution. No costs have been provided for the wider proposal so it is not possible to compare solutions and have a cost benefit trade off. If the costs of delivering the storage only solution is much higher, then a pragmatic way forward that encompasses Ofgem's specific concern would be to adopt the new original proposal. Ideally, all storage would be subject to the same BSUoS charges to give the greatest consumer benefit. This currently is not the case as embedded storage receives BSUoS when it exports as an embedded benefit and pays BSUoS when it imports (both of these either directly or via the supplier). ENGIE's CUSC modification CMP307 would have addressed the export side of BSUoS as it would have removed the embedded benefit and instead charged embedded storage when exporting. The Authority directed that CMP307 must not be made whilst the TCR SCR is ongoing as the TCR SCR is looking at embedded benefits. The anticipated storage definition within the generation licence could within CMP 281 be used to remove the BSUoS import charge from all licenced storage. However, this would create the situation where embedded storage was not paying BSUoS on its imports and continued to receive BSUoS as an embedded benefit. There would not therefore be a level playing field in BSUoS charging for all storage. Ideally, both these changes therefore need to be in place before BSUoS import charges for embedded storage are removed. There is therefore no reason for CMP281 to address embedded storage for the time being. It is however likely that the storage class within the generation licence will be put in place before the embedded BSUoS benefits issue is resolved. In the response to Q4, ENGIE has suggested an alternative modification that just limits CMP281 to storage with a BCA (and BELLA/BEGA over 100 MW) and a storage generation licence or, in the absence of storage generation licence, a notice to National Grid from Ofgem. Ofgem will need to give thought as to whether it is appropriate to create differences in the payment of BSUoS for transmission and distribution connected storage once the licence is in place

Standard Workgroup consultation		
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider**?	**If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website1, and return to the CUSC inbox at cusc.team@nationalgrid.com** Yes. To address the points made in the response to Q3, the following definition of an "An Exemptible Storage BMU" is proposed. We put forward the following solution to the narrow scope simple solution and have raised this as a consultation alternative: ========== A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting): All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Storage BMUs shall be disregarded. For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology – An Exemptible Storage BMU is a BMU that : is listed in Appendix C of a bilateral connection agreement (BCA) that is associated with an electricity storage facility as set out in the Generation Licence; or is listed in a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Embedded Licence exemptible Large power station Agreement (BELLA) above 100MW in size and are associated with an electricity storage facility as set out in the Generation Licence; or the Authority has directed that the BMU is an Exemptible Storage BMU for the purpose of the CUSC Part (a) of definition is designed to only cover transmission-connected storage as only this type of storage has a BCA and will be active once the definition of storage in included in the generation licence. We do not believe that any BEGA or BELLA storage facilities exist but have put definition (b) in for completeness. Part (c) allows transmission-connected storage to be identified prior to a licence definition being in place with the authority issuing a notice to National Grid. The Authority would issue a notice identifying for each transmission connected storage BMU (Appendix C part 3 of the BCA).

Specific questions for CMP281

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

5	Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?	The modification will result in a lowering of overall cost to consumers based on more efficient market operation. In terms of billing arrangements, it is likely to have minimal effect on both National Grid and other parties to the CUSC.
6	Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?	As noted in the response to Q3, ENGIE would support just limiting CMP281 to CVA storage or widening it to all transmission connected generation demand. Removing BSUoS charges from all but “end consumption” will lead to a more efficient energy system with reduced costs for consumers. It is for Ofgem to decide whether or not the scope of the modification should just be limited to storage and for Ofgem to take into account the cost differential of the two options. It is important that both options are put to Ofgem to given them the choice.

APPENDIX 1

CMP281: REMOVAL OF BSUOS CHARGES FROM ENERGY TAKEN FROM THE NATIONAL GRID SYSTEM BY STORAGE FACILITIES

Summary

Storage operators currently pay BSUoS on both their import and export volume from and to the grid. CMP281 proposes to remove the liability from storage to pay BSUoS charges on imported volume. Engie has conducted an analysis of both the costs and benefits of such a measure for other market participants (particularly focused on consumers).

It is estimated that removing BSUoS from transmission connected pumped hydro imports pumping will increase overall BSUoS by on average 2p/MWh and by 5p/MWh if the increase is just applied to those paying BSUoS overnight.

Offsetting this increase, there will be a benefit in terms of lower peak traded prices as the pumped storage 'fuel' costs will be lower allowing it to generate in periods when it would have been 'out of the money' due to paying BSUoS on imports. This is estimated to save consumers around £36m giving a net benefit of around £15m. On top of this the cost of managing constraints arising from excess overnight generation can be expected to fall.

Estimated Cost Impact

If implemented, the storage sites that would become exempt from import BSUoS charges are the existing pumped storage (PS) sites (Foyers, Cruachan, Dinorwig and Ffestiniog) and existing and planned battery storage projects.

Engie has examined historic BSUoS charges to understand the impact of CMP281. In 2015 the volume of imports to PS sites totalled 3,701GWh out of a total generation and demand volume of 526,408GWh (includes only generation and demand subject to BSUOS charges). PS sites contributed £10.64m to the total BSUOS charge of £1,135m. The cost of BSUoS was £2.16/MWh (£1,135m divided by 526,408GWh) and would have been £2.17/MWh if PS had been exempt from paying BSUOS on imports (£1,135m divided by 522,707GWh). The impact on average BSUOS charges across the year would have been £0.016/MWh in 2015. Similar impacts would have occurred in 2016 and 2017 YTD (see table 1).

Table 1: BSUoS Costs/Volumes since 2015

Year	PS Imports BSUoS (£k)	PS Imports (GWh)	Total BSUOS (£k)	Total Volume (GWh)	Actual BSUoS Cost (£/MWh)	CMP281 BSUoS Cost (£/MWh)
2015	10,643	3,701	1,135,132	526,408	2.16	2.17
2016	12,247	4,002	1,219,830	522,303	2.34	2.35
2017 (H1)	6,127	2,020	601,007	254,545	2.36	2.38

The overall cost to other market participants from removing BSUoS charges on imports would have been an annualised £10.6m to £12.2m since 2015. Looking just at the impact on overnight BSUoS, the impact on other market participants between 23:00 and 07:00 would be around 5p/MWh on average.

However, additional PS demand would have occurred overnight with CMP281 in place (estimate 246.4GWh of additional pumping) which would reduce the impact on other market participants. In addition, by increasing demand in regions with excess generation (particularly during high wind/low demand periods where currently PS is uneconomic due to high BSUoS charges), the additional consumption would have contributed to alleviating constraint costs. Therefore, overall the cost of implementing CMP281 would be less than the £10.6m to £12.2m range outlined above.

Estimated Benefits

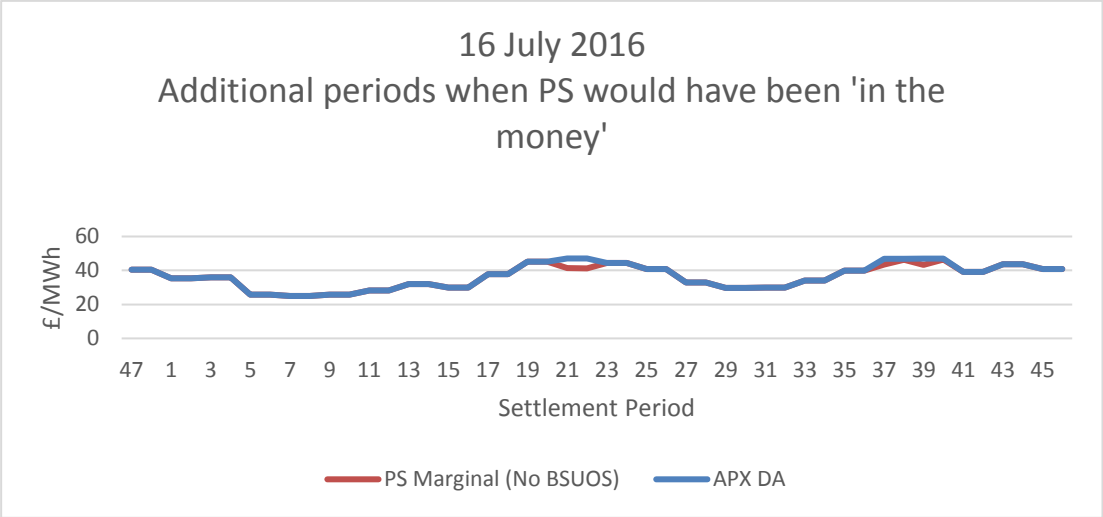
Engie has investigated the potential benefit to consumers from removing the BSUOS charge from volume imported by storage sites. The basic premise is that import BSUoS increases the price at which storage sites are able to generate during demand peaks. The result is PS generates for fewer hours each year and when it is generating at the margin sets a higher wholesale price.

The trader's BSUOS expectation would not be a flat value across a year but would be based on wind/demand forecasts and how these drive BSUOS costs. There is uncertainty about what the overall pumping cost will be but traders will make a judgement and trade to their expectation of the BSUoS cost of replacing the stored energy (potentially with a risk premium added to cover forecast error). Removing BSUOS costs mean traders will factor zero BSUOS into offer prices, which will reduce them compared to their previous expectation and lead to the lower extended peak prices.

To determine the benefit, ENGIE looked at a 12 month period from 14th July 2016. Engie calculated the cost of pumping using a simplified formula to create by adding BSUoS to the next day's APX DA auction price. Dividing by 0.75 (to represent a 75% efficient PS site) gives an estimate of the strike price at which PS sites could generate in the following demand peak.

Removing BSUoS charges from pumping costs changes the formula above to just the APX DA auction price divided by 0.75. This means the reduction in generation costs from removing BSUoS is amplified and has a greater impact on costs during peak demand periods.

To determine the impact of removing BSUoS charges from import volume, Engie compared the highest priced 8 hours clearing in the APX DA auction for extended peaks (Ext PK) to the cost of generation of PS (taking account of the BSUoS cost applied to exports). It is assumed for simplicity that pumping occurs overnight. The aim is to find the settlement periods where PS is marginal and where the reduction in pumping costs will reduce the wholesale price. Ranking the overnight periods and matching the lowest prices to the highest extended peak prices shows the half hours where PS is deeply in the money (no price impact) or out of the money even without paying BSUoS costs on imports (no price impact). Marginal periods are defined as ones that cleared between the cost of generation with BSUoS and the cost without BSUoS. These are the periods where CMP 281 would have an impact.



Removing BSUoS and assuming that PS generates at cost would allow PS to break even in settlement periods 19 to 23 and 37 to 40 in the example above (price data taken from 16th July 2016) where previously it would have been out of the money.

For the 12 months from 14th July 2016, the average Ext PK price (including weekends, settlement periods 15 to 46) was £50.05/MWh. Following the methodology above for PS means the average price falls to £49.92/MWh. Out-turn demand for the period examined is 198.4GWh meaning a total saving to consumers of £25.8m. The net benefit of this change is therefore around £15m.

An alternative way of looking at the benefit would be to look at the average BSUoS costs for the same period (£2.69/MWh) and apply the above methodology to again determine the periods when pumped storage would move to being in the money. The result is the benefit drops from £0.14/MWh to £0.09/MWh or £17.9m giving a net benefit of around £9m. Given that BSUoS costs are higher overnight to manage the excess of wind on the system, using an average value is not appropriate. Whilst it can rightly be argued that traders will not have perfect foresight of BSUoS, as noted above they would make a judgement using in house analysis tools. Their judgement would produce a more relevant value than a flat assumption.

Other Benefits

One clear benefit of this reform is that it will encourage investment in new storage assets (particularly transmission connected battery storage projects) by improving the economics of such projects. As it stands there is a strong correlation between periods of high wind and low demand (when storage sites could offer a valuable service helping to manage renewable intermittency) and high BSUoS costs (often more than £10/MWh). Removing BSUoS costs from pumping improves the arbitrage potential in these periods and removes a major uncertainty.

Other benefits to the proposal include lower break even costs for providing ancillary services (particularly response services), which would translate into lower procurement costs and potential cost reductions in the Balancing Mechanism and Capacity Market.

If the modification was widened such that all transmission connected generation did not pay BSUoS when its net HH transmission connected metering was negative, the average increase in BSUoS to the remainder of the market would be around 4p/MWh over the same period. An assessment has not been made of the impact on overnight BSUoS as transmission connected generation may also be consuming during the daytime.

Appendix 2

Stage 1 Initial request

A CUSC party writes to Ofgem and requests a “part C” notice be issued to National Grid relating one of its power stations that it believes should be categorised as storage and lists the BMUs it considers should be an “Exemptible Storage BMU”

The application provides sufficient evidence to allow Ofgem to consider the request typically including:

a) Bilateral Connection Agreement listing the BMU’s: and
b) Outline details of the type of storage (e.g. pumped hydro, battery compressed air) and details of the location of the site; and
c) A directors statement that the power station is used as:-

(a) a means of converting electricity imported from the National Grid system into a form of energy which can be stored, and of storing the energy which has been so converted; and
(b) a generating unit which is wholly or mainly used to re-convert the stored energy into electrical energy for the purpose of its supply to the National Grid system.

Stage 2

Ofgem consider the request asking for additional information if it requires any then if appropriate issues the “part C “ notice to National Grid ESO with a copy to the requesting party. The notice would state the applicable date.

Stage 3

National Grid ESO would ensure notified BMUs were treated as Exemptible Storage BMU’s from the applicable date and not subject to demand BSUoS.

CUSC WORKGROUP CONSULTATION ALTERNATIVE REQUEST FORM

Please send your completed form along with your completed Workgroup Consultation Response to ###### by ####.

Please note that any responses received after the deadline may not receive due consideration by the Workgroup.

Respondent Name and contact details	*Simon Lord* *Simon.Lord@engie.com*
CMP281 [Add – Title of the Modification]	
Capacity in which the WG Consultation Alternative Request is being raised : (i.e. CUSC Party, BSC Party or "National Consumer Council ")	CUSC party First Hydro

Description of the Proposal for the Workgroup to consider*(mandatory by proposer)*:

The alternative to CMP 281 simplifies the original CMP 281 solution by ensuring it only applies to transmission connected and larger embedded (over 100 MW) storage power stations with a BCA

Extension to embedded storage is not appropriate without further reform of the embedded benefit regime. Ofgem has recently stated that embedded BSUoS benefits are now part of the current TCR SCR and such a change must not be made whilst the TCR SCR is ongoing.

The Appendix C of the CUSC lists BMU's that are contained in the BCA. The part of the solution that utilises the storage class within the generation licence does not go into further details as until the Generation licence is changed by Ofgem and a storage class is created, there is no value in going further and "second guessing" how the licence may be drafted. It is recognised that a further change may be needed depending on storage class licence drafting.

Part (c) of the legal text therefore allows Ofgem to issue a notice to National Grid ESO prior to the creation of the storage class within the generation licence to designate "Exemptible storage BMUs". This will facilitate a timely implementation of this modification.

==========

A solution is to amend the text in CUSC 14.29.4 along the following lines (subject to legal drafting):

All CUSC Parties acting as Generators and Suppliers (for the avoidance of doubt excluding all BMUs and Trading Units associated with Interconnectors) are liable for Balancing Services Use of System charges based on their energy taken from or supplied to the National Grid system in each half-hour Settlement period, except that energy taken from the system by Exemptible Storage BMUs shall be disregarded.

For purpose of Section 14(2) of the CUSC – The Statement of the Balancing Services Use of System Charging Methodology –

An Exemptible Storage BMU is a BMU that :

(a) is listed in Appendix C of a Bilateral Connection Agreement (BCA) that is associated with an electricity storage facility as set out in the Generation Licence;

or

(b) is listed in a Bilateral Embedded Generation Agreement (*BEGA*) or Bilateral Embedded Licence exemptible Large power station Agreement (BELLA) above 100MW in size and are associated with an electricity storage facility as set out in the Generation Licence;

or

(c) the Authority has directed that the BMU is an Exemptible Storage BMU for the purpose of the CUSC

==========

Ofgem Notice process (Part 3) not part of CUSC

Stage 1 Initial request
A CUSC party writes to Ofgem and requests a "part C" notice be issued to National Grid relating one of its power stations that it believes should be categorised as storage and lists the BMU's is considers should be "Exemptible Storage BMU"
The applicant party provides sufficient evidence to allow Ofgem to consider the request typically including :-

a) Bilateral Connection Agreement listing the BMU's,
b) outline details of the type of storage (e.g. pumped hydro, battery compressed air) and details of the location of the site.
c) A directors statement that the power station is used as:-

(a) a means of converting electricity imported from the National Grid system into a form of energy which can be stored, and of storing the energy which has been so converted; and
(b) a generating unit which is wholly or mainly used to re-convert the stored energy into electrical energy for the purpose of its supply to the National Grid system.

Stage 2
Ofgem consider the request asking for additional information if it requires any then if appropriate issues the "part C " notice to National Grid ESO with a copy to the requesting part. The notice would state the applicable date.

Stage 3
National Grid ESO would ensure notified BMU's were treated as Exemptible Storage BMU's from the applicable date and not subject to demand BSUoS.

Description of the difference(s) between your proposal compared to Original / Workgroup Alternative(s)

Builds on the solution proposed by the working group and includes an ability for Ofgem to notify National Grid ESO that a power station and associated BMU's should be treated as exemptible storage BMU's.

Justification for the proposal (*including why the Original proposal / Workgroup Alternative(s) does not address the defect*) *(mandatory by proposer)*:

Includes an ability for Ofgem to notify National Grid ESO that a power station and associated BMU's should be treated as exemptible storage BMU's prior to the implementation of the storage licence condition within the generation licence

Impact on the CUSC *(this should be given where possible)*
As per original CUSC proposal:

Impact on Core Industry Documentation *(this should be given where possible)*:
As per original CUSC proposal

Impact on Computer Systems and Processes used by CUSC Parties *(this should be given where possible)* :
As per original CUSC proposal*:*

Justification for the proposal with Reference to Applicable CUSC Objectives* *(mandatory by proposer)*:

Impact of the modification on the Applicable CUSC Objectives (Charging): Relevant Objective Identified impact

a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity);	**Positive :- Removing a distortion in competition will better facilitate competition.**
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	**A Positive : BSUoS charges are not intended to be cost reflective, this proposal will have little impact on cost reflectivity other than removing a distortion whereby some users pay a disproportionate amount of the costs.**

Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	No

Notes:

1. Applicable CUSC Objectives* - These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1. Reference should be made to this section when considering a proposed Modification.

CUSC Workgroup Consultation Response Proforma

CMP281 Removal of BSUoS Charges from Energy Taken from the National Grid System by Storage Facilities'

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **12 November 2018** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Joseph Henry at joseph.henry@nationalgrid.com

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

Respondent:	*Bill Reed bill.reed@rwe.com*
Company Name:	*RWE Supply & Trading GmbH*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection); (c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses*; (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity

	Transmission plc Licence under Standard Condition C10, paragraph 1; and (e) Promoting efficiency in the implementation and administration of the CUSC arrangements.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP281 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	CMP281 will better facilitate CUSC Objective (a). It will remove BSUoS charges from off takes related to electricity generators at facilities (BMUs and Trading Units) where that person is carrying on activities authorised by a Generation Licence. The proposed solution is a non-discriminatory approach towards implementation with respect to all Generation Licensees. The solution facilitates the BEIS/Ofgem Smart Systems and Flexibility Plan by enabling storage to benefit from the proposed arrangements once the relevant Generation Licence changes are implemented.
2	**Do you support the proposed implementation approach?**	We support the proposed implementation approach for the CMP281 solution. We note that the proposal as originally defined would have required new administrative proposals with respect to the definition of storage in the CUSC which would have been cumbersome to implement and difficult to enforce.
3	**Do you have any other comments?**	We have no other comments.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP281

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

5	**Can you confirm how CMP281 will impact CUSC Parties (for example, operations, billing, contractual, tariff stability, processes and information flows)?**	The CMP281 solution will have no impact on our billing or contracts and we do not believe that there would be any material implications for tariff stability.
6	**Do you believe CMP281 original proposal would level the playing field in the way that Ofgem and Government have intended in recent publications?**	The proposed CMP281 solution ensures that all generation including existing pumped storage generation would be relieved from the obligation to pay off taking BSUoS. This is compatible with the approach taken by BEIS/Ofgem in the designation of storage under the Generation Licence as envisaged in the Smart Systems and Flexibility Plan.