Code Administrator Consultation

CMP368: Updating Charges for the Physical Assets Required for Connection, Generation Output and Generator charges for the purpose of maintaining compliance with the Limiting Regulation

CMP369: Consequential changes to Section 14 of the CUSC as a result of the updated definitions introduced by CMP368

CMP368: To give effect to the Authority determination within the CMP317/327 decision published to amend the definition of Assets Required for Connection, create new definitions of 'GB Generation Output' and define Generator charges for use in the Limiting Regulation range calculation.

CMP369: To update CUSC with the updated definitions introduced by CMP368 and update the GCharge element to facilitate the removal of 'Large Distributed Generators' charges from the compliance calculation as directed by the Authority.

Modification process & timetable

1. **Proposal Form** 16 April 2021
2. **Workgroup Consultation** 11 June 2021 – 02 July 2021
3. **Workgroup Report** 02 August 2021
4. **Code Administrator Consultation** 10 August 2021 – 01 September 2021
5. **Draft Modification Report** 06 September 2021
6. **Final Modification Report** 23 September 2021
7. **Implementation** 01 April 2022

Have 5 minutes? Read our Executive summary

Have 20 minutes? Read the full Code Administrator Consultation

Have 30 minutes? Read the full Code Administrator Consultation and Annexes.

Status summary: The Workgroup have finalised the proposer's solution as well as 19 alternative solutions (for CMP368 only). We are now consulting on this proposed change.

This modification is expected to have a: High impact on those CUSC Users who pay TNUoS charges.

Governance route	This modification has been assessed by a Workgroup and Ofgem will make the decision on whether it should be implemented.	
Who can I talk to about the change?	**Proposer:** James Stone, National Grid ESO James.Stone@nationalgrideso.com Phone: 07971002704	**Code Administrator Chair**: Jennifer Groome Jennifer.Groome@nationalgrideso.com Phone: 07966130854

How do I respond?	Send your response proforma to cusc.team@nationalgrideso.com **by 5pm on 1 September 2021.**

Contents

Executive summary

Following the Authority's approval of the CMP317/327 Original Proposal, changes to the CUSC TNUoS charging methodology from 1 April 2022 are now required to ensure alignment with the Authority's decision.

What is the issue?

CMP368: The required changes to CUSC Section 11 include, in the assessment of compliance with the range, local charges in respect of local assets to the extent that such assets were pre-existing at the time the generator paying those charges wished to connect to the NETS. A further change to the CUSC is also required to facilitate the Authority's decision to remove charges and volumes associated with Large Distributed Generators (LDG) from the calculation determining compliance with the range.

CMP369: Section 14 of the CUSC needs to be updated to ensure that Generation Output, Generator charge variables and the definition of Charges for Physical Assets Required for Connection used within the methodology for assessing compliance with the Limiting Regulation are aligned with the definitional changes introduced by CMP368.

What is the solution and when will it come into effect?

Proposer's solution: Updates to Section 11 and Section 14 of CUSC as outlined above.

Implementation date: 1 April 2022.

Summary of potential alternative solution(s) and implementation date(s):

19 WACMs have been raised for CMP368, all with an implementation date of 1 April 2022. The WACMs build off the following variants:

- Whether to *include* **or** *exclude* the *volumes and charges* **or** *volumes only* associated with *LDG* **or** *Distributed Generators* in/from the compliance calculation.
- Whether to *include* **or** *exclude* demand transmission charges paid by generators (previously referred to as Station Demand in the Workgroup Consultation) in/from the compliance calculation.
- What the appropriate timestamp should be for determining Pre-Existing Assets.
- What constitutes as a sufficient level of 'interconnectedness' for charges associated with assets to not fall within the Connection Exclusion.

CMP368 Workgroup conclusions: The Workgroup by majority concluded that the Original, WACM7, WACM17, WACM18 and WACM19 better facilitated the applicable objectives than the current CUSC.

CMP369 Workgroup conclusions: The Workgroup concluded unanimously that the Original better facilitated the Applicable Objectives than the Baseline.

What is the impact if this change is made?

This change will have a high impact on those CUSC Users who pay TNUoS charges.

Interactions

CMP368 and its proposed definition changes has an interaction with CMP369 which is being proposed alongside this modification and that updates Section 14 of the CUSC to align the charging methodologies to the updated definitions.

What is the issue?

Proposer's View

CMP368: To maintain compliance with Regulation 838/2010 (the Limiting Regulation), NGESO perform a compliance assessment to ensure that the average annual transmission charge for all Generators is set within a range of €0-2.50/MWh when setting tariffs and that if this is not met an ex-post reconciliation process is performed to amend charges for Generators.

The Limiting Regulation specifies that "Charges for Physical Assets Required for Connection" (amongst others) are excluded when assessing compliance. These are currently expressed within the "Charges for Physical Assets Required for Connection" (the 'Connection Exclusion') definition in Section 11 of the CUSC.

The definition within the CMP317/327 Original Proposal approved by the Authority on 17 December 2020, excludes all local charges for local circuits and local substations paid by Generators when assessing compliance with the range in the Limiting Regulation. However, as part of their decision[1] the Authority stated, "We consider that charges paid by generators in relation to Local Assets which existed at the point at which such generator(s) wished to connect to the NETS do not fall within the Connection Exclusion".

In the decision, the Authority made it clear that they expected the ESO to bring forward a modification proposal to include, in the assessment of compliance with the range, local charges in respect of local assets (i.e. local substations and local circuits) to the extent that such assets were pre-existing at the time the Generator paying those charges wished to connect to the National Electricity Transmission System (NETS).

In addition, the Authority also expected any CUSC modification proposal(s) to remove from the calculation determining compliance with the range the TNUoS Charges payable by Large Distributed Generators and their associated volumes (MWh).

CMP369: CMP369 has been drafted to give effect to this direction and to refer to the definitions introduced in CMP368 which introduce definitions of these terms.

Why change?

Following the Authority's approval of CMP317/327 'Original Proposal', changes to the CUSC TNUoS charging methodology from 1 April 2022 are now required to ensure alignment with the Authority's decision to include, in the assessment of compliance with the range, local charges in respect of local assets to the extent that such assets were pre-existing at the time the generator paying those charges wished to connect to the NETS.

This interpretation was reinforced following the CMA decision regarding the recent 'SSE Code Modifications Appeal 2021[2]' whereby the CMA clarified (within paragraphs 6.91) the principles governing the correct interpretation of the "Connection Exclusion', stating:

[1] https://www.ofgem.gov.uk/system/files/docs/2020/12/cmp317327_decision_171220.pdf

[2] https://assets.publishing.service.gov.uk/media/60632cd6d3bf7f0c8c97d9f2/SSE_v_GEMA____-.pdf

"6.91 (d) The reference in the Connection Exclusion to 'the system' means the transmission system as it exists at the point that a new Generator wishes to be connected to it. We also note the following:

(i) For the purposes of the application of the ITC Regulation [this is the Limiting Regulation] in GB, 'the system' is 'the transmission system of Great Britain'.
(ii) Currently, the entire GB transmission system comprises the NETS. For so long as that remains the case, treating the NETS as 'the system' is correct (see paragraph 2.8).
(iii) In terms of the relevant point in time at which the determination should be made as to which Local Assets are considered 'pre-existing' (that is, part of the NETS), we note that GEMA's initial view was that the date of execution of the contracts between NGESO and the relevant Generator would be a reasonable proxy as to when a Generator wished to connect. This initial view was not specifically challenged in the present appeal and therefore we do not need to decide this point.

(e) When deciding whether or not a charge falls within the Connection Exclusion, it is necessary to ask whether the physical asset to which it relates is 'required for connection' by the Generator in question to 'the system' as it exists at that point. That is the same as asking whether, 'but-for' the asset, the Generator would be connected to the system.

(f) The physical assets which are determined to fall within the Connection Exclusion for a Generator continue to be required by that Generator for connection to the pre-existing system even once the Generator is operational. Put another way, connecting equipment for a Generator continues after the initial act of connecting to be 'required for connection to the system'. For the purposes of a Generator, the ambit of 'the transmission system' does not widen immediately upon the act of connecting that Generator.

In the decision above the CMA specify that the "system" for the purposes of the Limiting Regulation is the NETS and that charges for connections to this system should be considered "Charges for Physical Assets Required for Connection". However, the Proposer considers that it is clear that the system should be considered at the point that a Generator wishes to connect. This aligns with the direction given in Ofgem's CMP317/327 decision letter and means that charges for local assets which existed at the point at which such Generator(s) wished to connect to the NETS do not fall within the Connection Exclusion.

CMP369: Following the Authority's approval of CMP317/327 'Original Proposal', changes to the CUSC TNUoS charging methodology from 1 April 2022 are now required to ensure alignment with the Authority's decision to remove from the calculation determining compliance with the range the TNUoS Charges payable by 'Large Distributed Generators' and their associated volumes. To facilitate this, Section 14 of the CUSC needs to be updated to ensure that Generation Output, Generator charge variables and the definition of Charges for Physical Assets Required for Connection used within the methodology for assessing compliance with the Limiting Regulation are aligned with the definitional changes introduced by CMP368.

What is the solution?

Proposer's solution

CMP368

CMP368 seeks to:

- Amend the definition of "Charges for Physical Assets Required for Connection" (which determines the scope of the "Connection Exclusion") to exclude local charges for pre-existing assets, and;
- Exclude TNUoS Charges and volumes associated with TNUoS-liable Distributed Generators who are party to a Bilateral Embedded Generation Agreement and are Licensable Generation.

Amend the definition of "Charges for Physical Assets Required for Connection"

A change to Section 11 of the CUSC is required to exclude from the definition of "Charges for Physical Assets Required for Connection" charges for those assets that were pre-exisiting at the time the generator wished to connect. This will reflect the Authority interpretation that charges paid by generators in relation to local assets which existed at the point at which such generator(s) wished to connect to the NETS do not fall within the Connection Exclusion, thus allowing NGESO to include local charges related to such pre-existing assets, in the assessment of compliance with the Limiting Regulation range.

It is proposed that that those assets which should be regarded as 'pre-existing' local assets would be determined by reference to the assets that existed as at the date of the Bilateral Connection Agreement for those generators who wished to connect to the National Electricity Transmission System. This will then allow the timestamping of assets to the associated Generator and/or TEC values (for Onshore) to be identified.

Exclude TNUoS Charges and volumes associated with TNUoS-liable Distributed Generators who are party to a Bilateral Embedded Generation Agreement and are Licensable Generation

In addition to updating the definition of "Charges for Physical Assets Required for Connection", a further change to Section 11 of the CUSC is also required to define the 'Generation Output' element used within the charging methodology calculation to determine compliance with the range. It is proposed that this definition would be total Output of GB generation liable for the TNUoS generation charge, excluding the associated volumes (MWh) relating to TNUoS-liable Distributed Generators who are party to a Bilateral Embedded Generation Agreement and are Licensable Generation.

Furthermore, Section 11 of the CUSC will also require a change to define the forecast generator revenue and actual charge elements used within the charging methodology calculation specifically ensuring that Large Distributed Generator Charges are not considered as per Ofgem's CMP317/327 decision.

CMP369

The CMP369 proposal is to update the definition of 'GO' and 'GOa' (used within the calculation detailed within Section 14.14.5 and 14.17.37 of the CUSC for the purpose of compliance with the Limiting Regulation) to align with the definition of GB Generation Output introduced by CMP368.

Additionally, propose to update the legal text relating to 'GCharge' (used within the same calculations and sections of the CUSC) to adopt the definitions of 'Forecast Transmission Generator TNUoS Charges' and 'Actual Transmission Generator TNUoS Charges' also introduced via CMP368. This will then allow NGESO to facilitate the Authority's CMP317/327 decision by removing from the calculation determining compliance with the range those volumes and charges associated with Large Distributed Generators and to take into account charges for pre-existing assets in tariff setting and any ex-post reconciliation processes.

This Proposal will affect the overall level that Generators and Suppliers pay for their Transmission Network Use of System (TNUoS) charges by incorporating the definitions within CMP368 thereby altering the amount that the Adjustment Tariff for Generators and residual charge for Suppliers recovers.

Workgroup considerations

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

Before discussing the Proposer's solution, the Authority Representative provided the Workgroup with guidance, (which can be found in Annex 3) on the Authority's expectations regarding the scope of CMP368 and CMP369. The Authority Representative stated that this guidance is to mitigate any risk that the modification process could result in no proposals being developed that are fully aligned with the correct interpretation of the Limiting Regulation, as occurred in CMP317/327.

The Authority Representative noted that this guidance has also been provided to help reduce any perceived requirement for industry to develop multiple alternative proposals, providing for different outcomes.

To aid their understanding, the Workgroup discussed a number of High-Level Principles, covering various scenarios in relation to how assets would be categorised, for example when they would/would not fall within the Connection Exclusion, and how the associated charges would be derived. These are included in Annex 7.

The Workgroup discussed the Terms of Reference provided by the Panel and agreed to an amendment to take into account the CMA's decision[3] of 30 March 2021 on the SSE appeal.

Section 11 - Definitional Changes proposed by CMP368

[3] https://assets.publishing.service.gov.uk/media/60632cd6d3bf7f0c8c97d9f2/SSE_v_GEMA____-.pdf

Large Distributed Generators

The Proposer stated that they have interpreted the CMP317 & CMP327 Ofgem decision to mean that a change is required to *"Remove from the calculation determining compliance with the range the TNUoS Charges payable by 'Large Distributed Generators' and their associated volumes"*.

The Proposer considers that, in practice, this means that both the TNUoS charges and the volumes associated with TNUoS-liable Distributed Generators who are party to a Bilateral Embedded Generation Agreement and are Licensable Generation should not be considered when calculating compliance with the Limiting Regulation.

The Proposer worked out the overall impact that this removal would have on the revenue liable for consideration in the calculation of compliance with the Limiting Regulation.

(£m)	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Revenue from large embedded generation	6.01	7.09	7.50	9.18	9.11	9.30

However, a Workgroup member noted that the approach suggested by the Proposer for the charges paid by TNUoS-liable Distributed Generators did not comply with the wording in the Limiting Regulation, namely:

> "*Annual average transmission charges paid by producers is <u>annual total transmission tariff charges paid by producers</u> divided by the total measured energy injected annually by producers to the transmission system of a Member State*"[4] [emphasis added]

An alternative has been raised to ensure that only the charges were included when the ESO calculating compliance with the statutory range, but the volumes were not as the energy from distribution connected generation was not injected to the transmission system.

It was queried by a Workgroup member whether the ESO are obligated to publish the calculation/data to determine compliance with the Limiting Regulation. The Proposer confirmed that this was not an obligation. A Workgroup member showed concern that without visibility of the calculation there is no evidence that the ESO has complied with the Direction or Limiting Regulation and suggested that a change be made to the legal text to obligate the ESO to publish the calculation/data determining compliance. The Proposer considered that the suggestion by a Workgroup member to change was not necessary given it is already being provided. However, following the Workgroup Consultation there was further support for this being part of the legal text. The Proposer agreed to include a hook within the CMP369 legal text (14.14.6) to facilitate this suggestion.

Charges for Physical Assets Required for Connection

It was noted by the Workgroup that the 'Connection Exclusion' has been defined, within the Limiting Regulation, as:

[4] Limiting Regulation, Part B paragraph 2.

> *"Charges paid by producers for physical assets required for connection to the system or the upgrade of the connection"*[5].

The Proposer stated that Ofgem have specified that charges for "pre-existing" assets (PEA) should not fall within the 'Connection Exclusion' when assessing compliance with the Limiting Regulation.

The Proposer considers "pre-existing" to mean the date when a generator signs its Bilateral Connection Agreement (BCA) with NGESO, and that the charges for those local assets that form part of the pre-existing NETS should therefore be included in the assessment of compliance with the Limiting Regulation; and therefore local charges associated with those pre-existing assets will not be part of the 'Connection Exclusion'.

This approach would also require the ESO to determine the charges for those local assets that were Non Pre-Existing Assets (NPEA). A Workgroup member believed this should include taking account of those Post-BCA Assets (i.e. those assets not forming part of the BCA signed by the generator with NGESO, that are built after the date when the generator signs its BCA). Another Workgroup member wondered if such assets should be considered an "upgrade of the connection" notwithstanding that the upgrade was not triggered by that generator, but instead by another generator, because the wording in the Limiting Regulation refers to "the connection" not "their connection".

A Workgroup member challenged what is meant by the term 'producer' and 'generator' in this context. It was confirmed by the Proposer and another Workgroup member that the definition of 'producer' is not defined in the Regulation 838/2010[6], however it is defined in Directive 2009/72/EC[7], where producer is defined in Article 2 as "*a natural or legal person generating electricity*". It was also noted that during the latest (2021) and previous (2018) CMA appeal decisions relating to the Limiting Regulation that Ofgem, the appellants and the CMA have all agreed that the term 'producer' and 'generator' are the same.

The Workgroup also examined the CUSC in terms of storage and confirmed that storage which generates electricity is classed as a generator, regardless of whether or not it holds a Generator Licence. The Proposer shared with the Workgroup Ofgem's 'Decision on clarifying the regulatory framework for electricity storage: changes to the electricity generation licence'[8] (published October 2020) which states:

> *"Alongside government, we have clarified our view that in the energy system, storage provides services equivalent to generation. Therefore, our view is that electricity storage – for licensing purposes - should be treated as electricity generation."*

The Workgroup considered the definitions that may be applicable following the CMA decision and the adoption of the relevant EU legislation into GB legislation. Specifically,

---

[5] Limiting Regulation, Part B paragraph 2(1)
[6] https://www.legislation.gov.uk/eur/2010/838/contents/adopted
[7] https://www.legislation.gov.uk/eudr/2019/944/article/2
[8] Decision on clarifying the regulatory framework for electricity storage: changes to the electricity generation licence (ofgem.gov.uk)

the definitions applicable for licenced generation and clarification of producer, generator and energy storage as set out in the recast electricity directive 2019/944[9]. The distinction between different types of storage and treatment with the CUSC, Grid Code and RFG was also briefly touched upon. It was also noted that Regulation (EU) 2019/943[10] establishes that 'network charges shall not discriminate either positively or negatively against energy storage'.

A Workgroup member questioned if the proposal affected how storage would be treated when assessing compliance with the Limiting Regulation. The Proposer noted that they are not proposing to amend the existing treatment of charges and volumes related to transmission connected storage assets i.e. storage in a transmission connected power station is treated the same way as other generating units and as such the associated charges and exporting volumes are included for the purpose of the compliance assessment. Therefore, as now, the transmission charges paid by pump storage and other storage like, for example, batteries and the associated volumes will be included (rather than excluded) when undertaking the Compliance Calculation.

A Workgroup member questioned what counts as the signing of the BCA agreement, in terms of whether this is the date when the generator and ESO enter into the relevant BCA agreement or when they sign the offer. The Authority Representative confirmed that in the Authority's view it is the date when the BCA is signed.

A Workgroup member also challenged what happens with the agreements which have not yet been signed, however TO investment plans have been either already designed, or already approved by the Authority (and thus the associated local assets could therefore be considered as 'pre-existing' and not required for the connection of the individual generator in question).

The Proposer confirmed that from the BCA documentation the ESO would be able to determine the necessary enabling works associated with a generator. This could allow the ESO to assess what element of the local charges were PEA or NPEA.

However, a Workgroup member noted that where those works (such as Shared Secured Enabling Works) were not for assets required for a generators' connection then they should not be placed into the 'Connection Exclusion' as they did not meet the autonomous test set by the CMA.

The Authority Representative provided the Workgroup with their view on what they interpret 'Connection Exclusion' to mean:

> *"Connection Exclusion is that charges paid by a generator fall within the Connection Exclusion if they are for assets that were required to connect that generator to the system, as the system existed at the time when the generator wished to connect, or for the upgrade of that connection. In this context we consider the system to be the 'NETS'."*

Currently it is the case that charges for offshore assets are associated with a specific project, until there are integrated offshore systems, and the Proposer considers there are currently no pre-existing assets to consider other than any existing interlinks; however, it

[9] https://www.legislation.gov.uk/eudr/2019/944/article/2
[10] https://www.legislation.gov.uk/eur/2019/943/contents

was noted by the Workgroup this may change in the medium term with, for example, the ongoing Offshore Transmission Network Review being undertaken jointly by BEIS, and Ofgem.

Charges for onshore assets need to be assessed against an updated definition of Charges for Physical Assets Required for Connection to ensure that these are appropriately accounted for in the calculation of compliance.

The Proposer provided the below estimates of the additional revenue that would be captured at the point of tariff setting based on the Proposers' interpretation of the PEA charges and the inclusion of those charges in the compliance calculation.

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.6*	1.94*	2.10*	3.69*	18.42*	19.27*

*Based on an "anchor project", i.e. local charges for sole users are connection exclusion; if multiple projects are in the same local network, assuming the one with the highest TEC triggered the local assets and thus pay connection exclusion.

The Proposer provided a spreadsheet to explain how the compliance calculation is calculated. This can be found in Annex 6.

Pre-existing Assets: Areas to Consider

Area for consideration	Proposer View	Workgroup Member(s) View(s)
TNUoS local charges with respect to transmission infrastructure assets which were built as "enabling works" for the relevant generator(s);	Enabling works by definition appear to not be pre-existing as they would not be needed but for that connection.	Some of the enabling works may not be required for the connection of a generator (so should not be within the 'Connection Exclusion') which means the ESO needs to assess each situation on a case by case (or rather BCA by BCA) basis.
The treatment of local charges for offshore assets and specifically the treatment of offshore interlinks;	Offshore assets are not pre-existing as they are required for a specific generator other than interlinks which would need to be considered on the basis of the generator that drove the investment.	The Workgroup agreed that charges for offshore assets are generally associated with a specific project and that until either (i) there are integrated offshore systems or (ii) an interlink is built the Workgroup consider there to be no pre-existing assets to consider (other than any existing interlinks).
Trigger events such as increases in TEC; reduction in TEC or closure of a generating unit(s);	Any changes in TEC should only drive a change to consideration of pre-existing if it results in additional reinforcement or system build. Only the incremental reinforcement should be	

	considered connection exclusion.	
Upgrades to the system and associated local circuits and substations for single generators or clusters of generators;	Pre-existing assets will exist where generators post the first connection are charged for these unless the enabling works are necessary for all generators.	No comment from the workgroup.
Generator "splits" whereby part of a generation unit is sold to another party and subsequently requires a new Bilateral Connection Agreement between NGESO and the Generator;	A new BCA and/or replanting should not in and of itself drive re-consideration of whether assets are pre-existing or not.	A producer is a person or legal entity not a generating unit, therefore the signing of a new BCA would mean a producer connecting to pre-existing assets and therefore this should drive re-consideration.
Generator "splits" whereby part of a generation unit is novated to another party	If there is a novation of agreements a new BCA is not required i.e. the name of the party is changed on the existing BCA.	If there is a novation, no new BCA is required.
The treatment of negative local circuit tariffs.	Negative local circuit tariffs should be assessed under the same principles as above.	The Workgroup agreed with the Proposer's statement that negative local circuit tariffs should not be treated differently.

Business Rules

The Proposer drafted a series of Business Rules to assist in the formulation of the proposed solution. The Proposer considered that these could form an Appendix within Section 14 of the CUSC and would provide further clarity and allow all parties to understand the process that the Proposer would follow and, if appropriate, seek to change them in the future via a CUSC modification proposal as any such Appendix would still fall within CUSC governance.

Determining Pre-Existing Assets and Non Pre-Existing Assets

1. To maintain compliance with the Limiting Regulation The Company will ensure that within the Adjustment Tariff setting process in 14.14.5 (v) Total Generator Charges will include charges for Pre-Existing Assets (PEA) contained within local charges.
2. For each charging year The Company will apportion the total amount of revenue recovered through local charges into charges related to "Pre-Existing Assets" (PEA) and charges related to "Non Pre-Existing Assets" (NPEA).
3. The Company will assign charges to each category at the time of tariff setting.
4. The categorisation of charges will be reviewed annually at the end of the charging year. This will ensure that any change to asset function for example assets being withdrawn or those assets required to connect an individual Generator to the system being deployed for a different purpose (i.e. the introduction of demand) is appropriately reflected in the categorisation.

5. Only charges for NPEA will be excluded from the calculation of the Adjustment Tariff.
6. Only charges for NPEA will be excluded from the calculation of ex-post compliance with the Limiting Regulation detailed in 14.17.37.
7. Local charges will be considered charges for PEA where these relate to assets that existed prior to the execution of the Bilateral Connection Agreement (BCA) unless there is a minor change to the BCA such as a change of legal entity, or a Modification Application whereby changes detailed within the Modification Application result in further work to local assets.
8. Local charges will be considered NPEA where these relate to assets that were built for the purposes of connecting a Generator or upgrading the connection of a Generator.
9. The Company will isolate the TEC value for each Generator associated with NPEA, and the local circuit tariffs associated with NPEA, to calculate the correct values.

Local tariffs

a. In cases where all the assets within a local network fall into NPEA then the full value of the local tariff will be used as the NPEA tariff. (i.e. offshore circuits, sole use assets, shared enabling works)
b. In cases where there are multiple assets within a local network that have differing classification, then the local tariff for a specific Generator site will be apportioned based on the relevant MWkM associated with each element of the tariff. I.e. if a PEA made up 3MWkM of the tariff and the remaining NPEA made up 2MWkM then the NPEA would attract 2/5 of the value of the local tariff.

TEC

c. When calculating the local charge for a Generator, its TEC is used as the charging base.
d. The TEC value for a Generator associated with its NPEA will be isolated from its total TEC, and is called its NPEA TEC.
e. The local charge derived from NPEA TEC and NPEA tariffs is the NPEA charge, and will be excluded from the calculation of compliance with the Limiting Regulation.
f. Local charges other than the NPEA charge will be deemed as PEA charges and will be included in the calculation of compliance with the Limiting Regulation.

It was highlighted by the Proposer that this solution would require additional resource and therefore incur implementation costs. The implementation would need an initial one-off cost for the identification and categorisation of assets and the potential creation of an asset register, and then ongoing costs at a reduced amount. Initially the proposer estimated the initial cost to be in the region of circa £500-700k (including 1 Full Time Employee and potentially 4 consultants), with ongoing costs of circa £200k per annum. However in a later Workgroup meeting, the Proposer amended this estimate to the value of £200k with ongoing costs of £200k per annum (for two additional FTEs), as they had a clearer understanding of the process and scope of the required data.

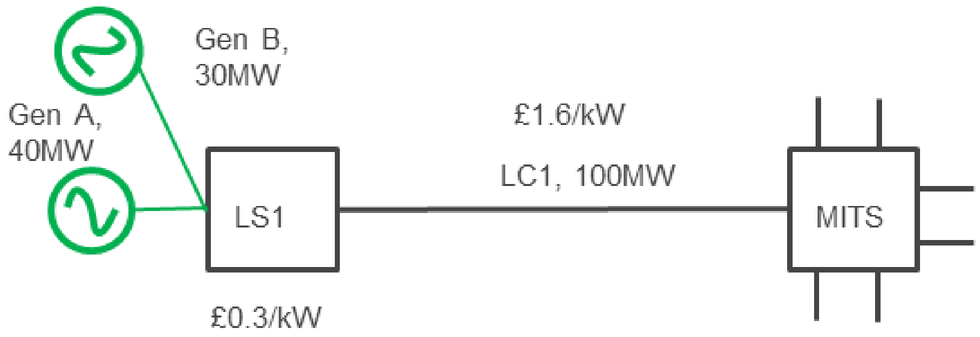
However, a Workgroup member noted that this was a matter of legal compliance with a Regulation that had been in existence for around 12 years, rather than something new. During this time the ESO (or its predecessor) had been through at least two price controls so it could be the case that the cost of compliance had already been factored into those price control settlements by the ESO / Ofgem. If so, then stakeholders had paid and continue to pay those costs already. The Workgroup member questioned whether these additional £500-700k initial costs and £200k ongoing costs were to also be recovered or whether this would be double counting. The Proposer highlighted that the indicative costs being discussed were in relation to the additional work required for the proposed solution to identify and categorise both assets required for connection, those assets considered to be pre-existing, as well as the potential creation of an asset register. As such, the Proposer expressed that it was highly unlikely there would be any double counting given this would be additional work to that included in any previous business plans and subsequent price control settlements.

Illustrative Examples – Potential Scenarios

Figures 1-7 (below) illustrate various scenarios that may arise in terms of identifying those charges that are associated with PEA or NPEA; the high-level principles and rules around how pre-existing local assets may be assigned; and how the associated charges would be allocated.

1. Scenarios for consideration with diagrams, and the proposer/Workgroup's views.
2. In all diagrams, circuits in green are owned by generators and are thus not transmission circuits (in the context of TNUoS local circuit charge, transmission circuits are defined as circuits owned by transmission owners).

Figure 1

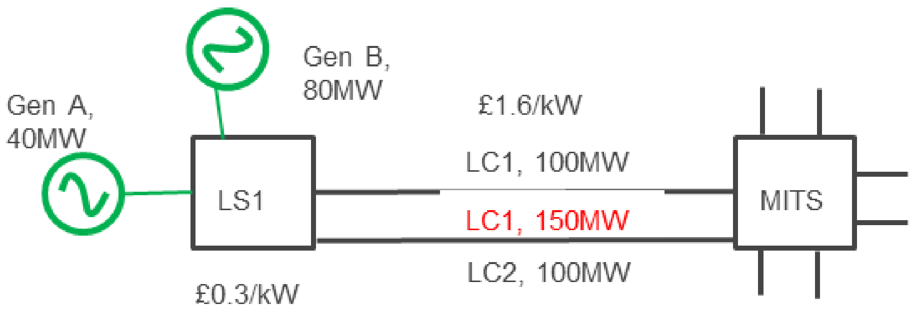


In Figure 1 there are 2 potential scenarios:

1. The TO offers and agrees a connection solution to build assets to connect both Generator A and Generator B. In this example, the works would be classed as "shared enabling works" within the BCA and as such assets required to connect, meaning the local charges associated with both generators would fall within the Connection Exclusion.
2. Generator A is already connected. However, at a later point in time, Generator B then wishes to connect. The TO may offer a connection solution to Generator B using the same point (the existing bay) at the local substation which Generator

A is already connected to. In this case, the local charges associated with Generator A still fall within the Connection Exclusion as they were required for it to connect. However, the local charges for Generator B would be classed as pre-existing (and would not fall within the Connection Exclusion) as Generator B would be utilising assets that were installed to connect the first generator and were already in use prior to them wishing to connect.

Figure 2



In the next example (Figure 2 above) Generator A required both the local substation and local circuit to be built to connect, therefore both sets of charges at this point in time fall within the Connection Exclusion.

At a later date, Generator B then connects but this time a new bay is required at the substation to allow its connection, meaning both Generator A's and B's local substation charges would fall within the Connection Exclusion.

However, as Generator B has agreed 80MW of TEC the existing 100MW local circuit cannot accommodate this increase in capacity without further reinforcements. In this case there are two possible scenarios required to connect Generator B to the system:

1) Thermal uprating of the local circuit from 100MW to 150MW or;
2) A second 100MW local circuit is built to accommodate the need for the additional capacity.

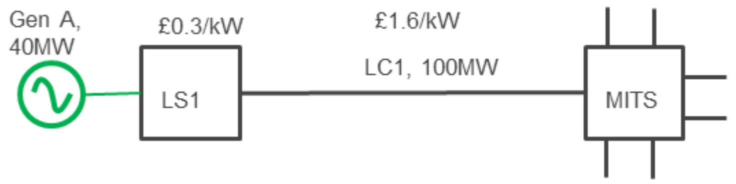
In both cases this would mean that Generator B is now the "trigger generator" of the local circuit asset reinforcements (either upgrade or new build) which were required to connect Generator B to the system.
The local circuit charges associated with generator A and calculated using the circuit rating of 100MW and single local circuit configuration, would fall within the NPEA; the local circuit charge associated with generator B using the single circuit configuration, would fall within NPEA. The remaining local circuit charges associated with generator A and B, using the local network configuration as in the relevant charging year, would be treated as charges associated with pre-existing assets.

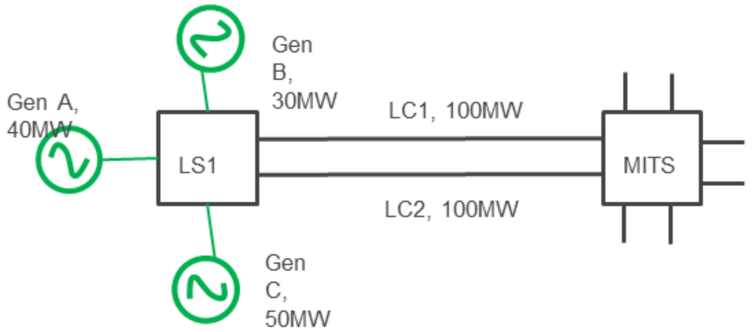
A Workgroup Member highlighted that if a new generator connects to a pre-existing local circuit, or an existing bay in an existing local substation, then no parts of those local assets are required for connection. Even if the capacity of parts of those local assets is increased, or additional new local circuits are built, none of those new network assets were required to connect the new generator. A generator could have connected to the local assets without those additions, even if it may have needed to be curtailed to manage local congestion. This interpretation is consistent with the approach currently used when connecting generators to the GB Distribution network on a financially non-firm basis and this principle is also applied to the GB Transmission network through the approach of Connect and Manage, a UK Government policy implemented some ten years ago which has not been repudiated or reversed by the UK Government, or Ofgem or the ESO. They further suggested that the Limiting Regulation exclusion reference to "upgrade of the connection" is only relevant for upgrades to assets that are required for connection, so if the assets are not required for connection, then it should not be relevant whether, or not they may have been part of an upgrade.

The Workgroup member also explained that the Limiting Regulation exclusion reference to "upgrade of the connection" is not relevant for these incremental network costs, because the relevant local assets being upgraded are pre-existing, so are not and never were part of the connection or required for the connection of the generator in question.

Figure 3

In the first diagram below, Generator A is already connected to the system but requests to increase its TEC from 40MW to 120MW. This triggers the need for the current 100MW local circuit to be uprated to 120MW. As the Generator in question is the only user triggering this required reinforcement work then the local circuit charge associated with the full 120MW of TEC (including both the initial 40MW at first connection and the additional 80MW upgrade) would fall within NPEA.

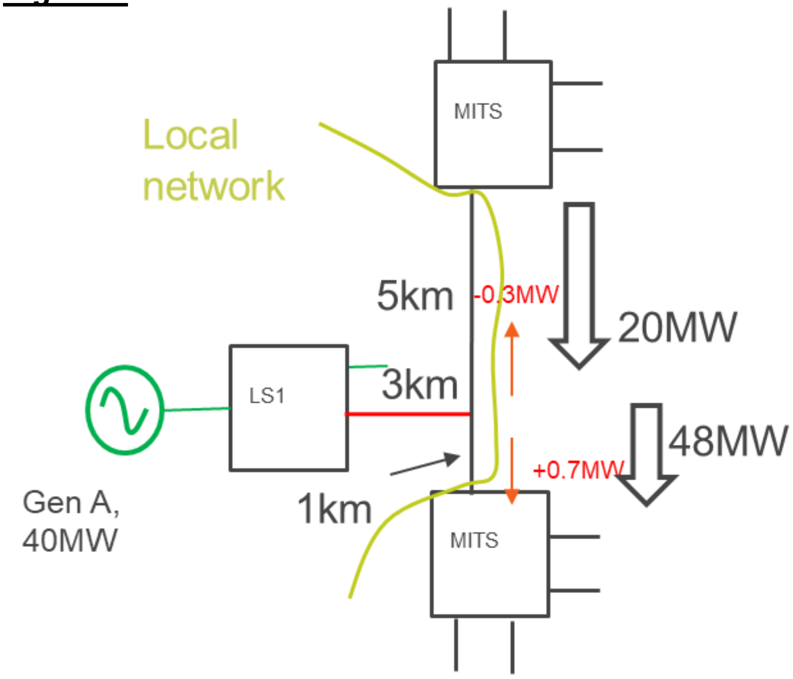




In the second diagram, an additional 100MW local circuit is built for Generator A to accommodate the increase in TEC to 120MW (rather than the option to uprate the existing circuit - detailed in the first example). In this case both local circuit charges would be classed as secured enabling works for Generator A and therefore would fall within NPEA.

However, after the assets are built, Generator A then requests to reduce its TEC to 40MW and both Generator B and C connect to new bays at the substation but without the need for any additional reinforcements to the local circuits due to the spare capacity now available (from Generator A's TEC reduction). In this scenario, the local substation charges for all Generators would fall within NPEA as all Generators required these assets to be built to connect. However, the local circuit charges relating to Generator B and C would be classed as PEA as they would be utilising assets already in existence/built at the point in time they wished to connect to the system.

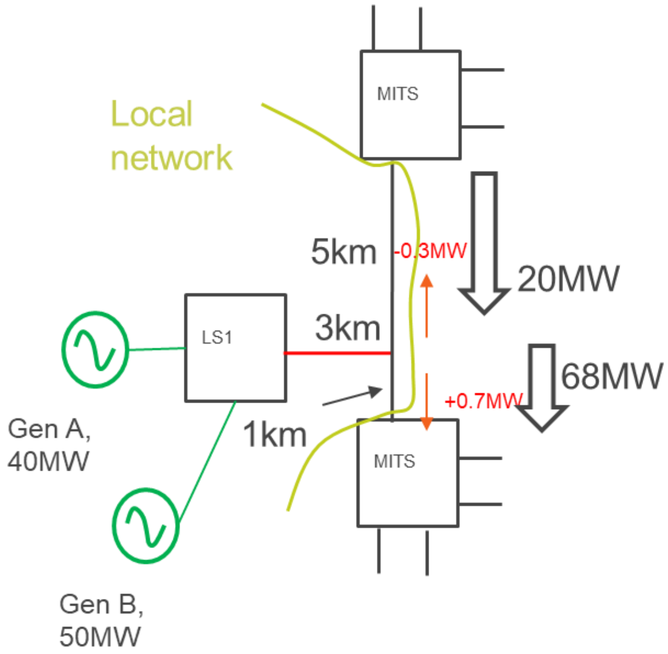
Figure 4



In the fourth diagram, the 3km of circuit section (in red) is built to connect generator A into the system. The two circuit sections in black, at 5km and 1km respectively, were part of the wider network prior to connection of generator A, and now become part of the local network.

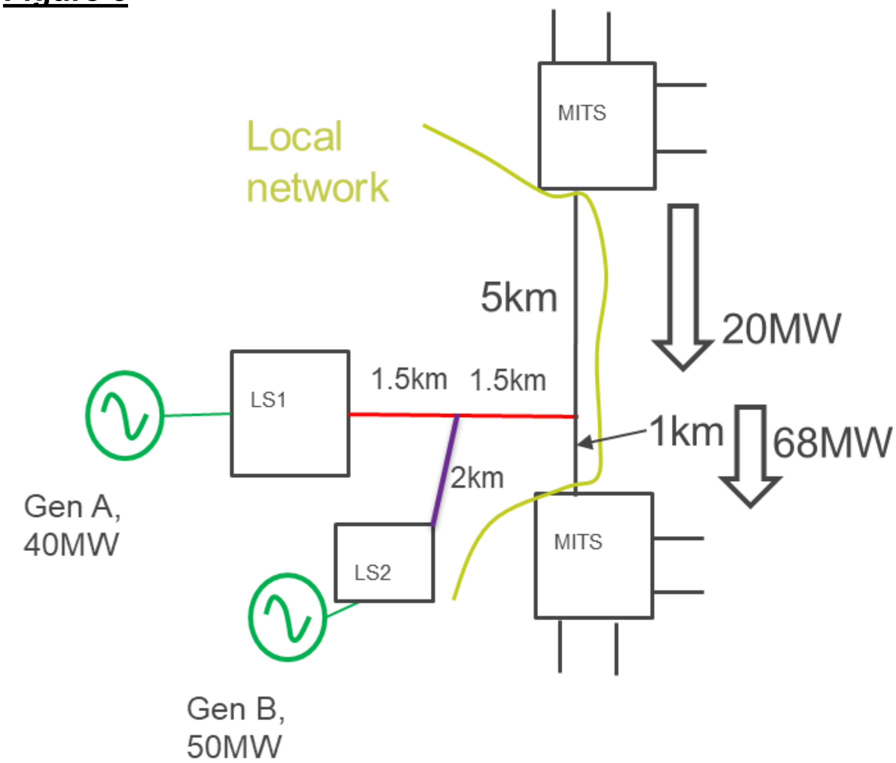
As the circuit sections in black were in the network when generator A wishes to connect, they are treated as PEA. The 3km of new section is an asset required for generator A's connection. The local circuit tariff will need to be broken down into two parts to reflect tariff elements associated with NPEA, and PEA. By applying the local circuit methodology (the incremental MWkm method), the local circuit tariff associated with the red section is 3km * 1MW = 3MWkm, while the local circuit tariff associated with the black sections is 5km*(-0.3MW) +1km*0.7MW = -0.8MWkm.

Figure 5



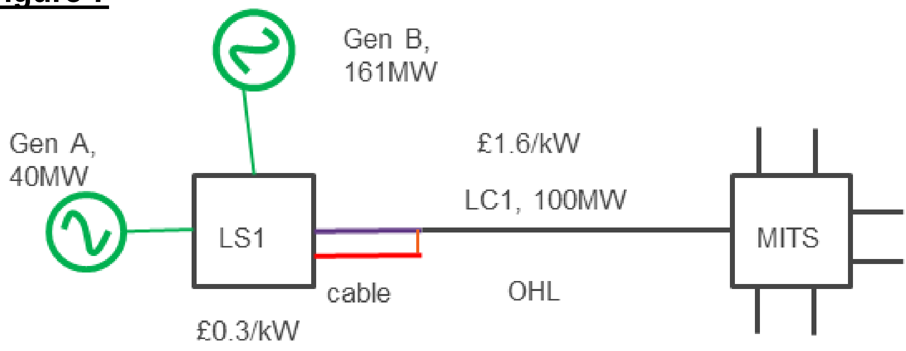
In the fifth diagram, after generator A (and the 3km of new circuit section) is energised, generator B also apply for a connection at the non-MITS substation LS1. Although both generators have the same local circuit tariff (as they connect at the same non-MITS substation), part of the local charge collected from generator A reflects the 3km of asset built for generator A (40MW) and should be treated NPEA; all local charges collected from generator B are charges associated with PEA.

Figure 6



In the sixth diagram, the circuit sections in red were built for generator A. Later generator B asked for a connection, and the purple circuit was built for generator B. Therefore, local charge associated with NPEA for generator A is the local tariff reflecting 3km of red section; and local charge associated with NPEA for generator B is the local tariff reflecting 2km of purple section. Local charges collected from generators A and B, after deducting the amounts of NPEA for them, will fall within PEA.

Figure 7



In the seventh diagram, the local circuit (between LS1 and the nearest MITS) has a small section of cable (about 300m), shown in purple, that links the overhead line to the substations. Generator A is the existing generator, and local circuit LC1 was built to connect generator A to the NETS. Local charges for generator A are NPEA.
Now generator B applies for a connection, and the related reinforcement work is to double up the small section of cable (show in red). In theory, the asset in red is new asset built for generator B, however, when building the circuit model for TNUoS tariff calculation, this reinforcement work is not explicitly captured in circuit modelling (as the circuit before and after reinforcement will have negligible parameter changes apart from thermal rating change), therefore local charges collected from generator B will all be treated as PEA.

Issues relating to "interconnectedness"

A Workgroup member noted that the CMA decisions noted, at paragraph 6.99(c)[11], the following regarding issues related to 'interconnectedness':

> *"The ITC Regulation [this is the Limiting Regulation] does not rule out the possibility that assets required by individual Generators for connection to the system could become assets deployed in the system for different purposes.*
>
> *If the function of assets, initially required by any such Generators for connection to the system, did change in this way, the charges applied for such assets may no longer fall within the Connection Exclusion, depending on the particular facts arising…Relevant factors may include the degree of interconnectedness between assets, and possibly also between Generators, suppliers and other users. However, these matters are complex and call for highly specialist technical expertise and the exercise of judgement by reference to the particular facts of the case."*

A Workgroup member highlighted that there are a few ways that 'interconnectedness' (as used by the CMA) could be taken into account when addressing the question of pre-existing assets:

[11] Pages 139-140.

1. **Option 1**: Only exclude charges for transmission network assets that are new (not pre-existing) and form a part of a single user generator only spur (GOS). This uses an objective test that any non-zero amount of interconnectedness is sufficient to change the purpose of the network assets in question. Even if those assets may have initially been required for a generator's connection, the fact that they have become interconnected means that they have become deployed in the transmission system for a different purpose, so the charges for such assets no longer fall within the Connection Exclusion. This provides an objective and autonomous definition of "enough interconnection". The only assets for which the ESO would need to apply the "pre-existing" test would be single user generator only spurs, which would greatly reduce the cost of resource and time required by the ESO to identify which assets are, or are not pre-existing. It would have the additional benefit of avoiding any need for ESO to carry out complicated calculations to arbitrarily attribute incremental network costs between different generators.

2. **Option 2:** Choose a degree of interconnectedness to qualify as "enough interconnectedness". This may include definitions such as two or more network branches, two or more generators, or at least one generator and a source of demand, it could borrow the same definition that the GB CUSC uses to define a MITS node, or use some other definition. A problem with this approach is that the choice of "enough interconnection" would be subjective and arbitrary whilst not providing an autonomous definition of interconnectedness for compliance with the Limiting Regulation.

3. **Option 3:** The CMA identified in paragraph 6.99(c), that there may be other relevant factors than just the possibility of the degree of interconnectedness between assets.

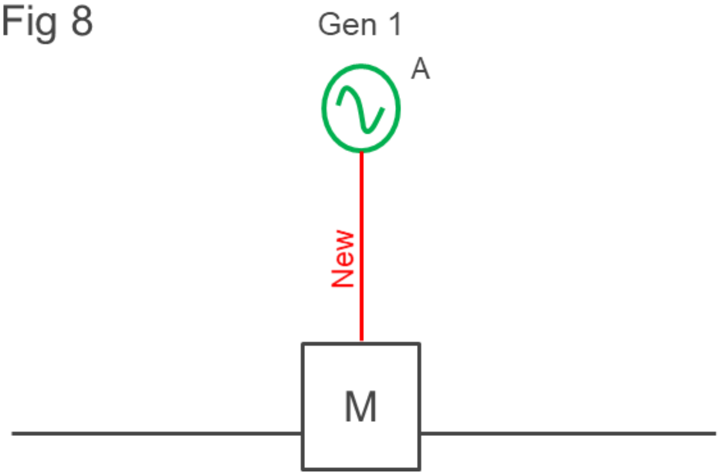
4. **Option 4**: Conclude that neither interconnectedness nor any other appropriate factor is relevant for the definition of the Connection Exclusion. The Authority decision suggested that changes in the function of the connection assets do not change the treatment of the charges for those assets in the context of the Connection Exclusion.

The Proposer believes that an appropriate level of interconnectedness is assets becoming part of the MITS and thus the Original would adopt the same definition as the MITS.

However, some Workgroup members had opposing views to this; noting, for example, that both Ofgem and the CMA had agreed on the transmission system, to which a connection is made, is the NETS not the MITS (as the Proposer had unsuccessfully argued with CMP317/327 Original); and the below diagrams were to aid discussion over what "degree of interconnectedness" would cause a change to whether charges applied to assets would no longer fall in the Connection Exclusion.

Figure 8

Fig 8



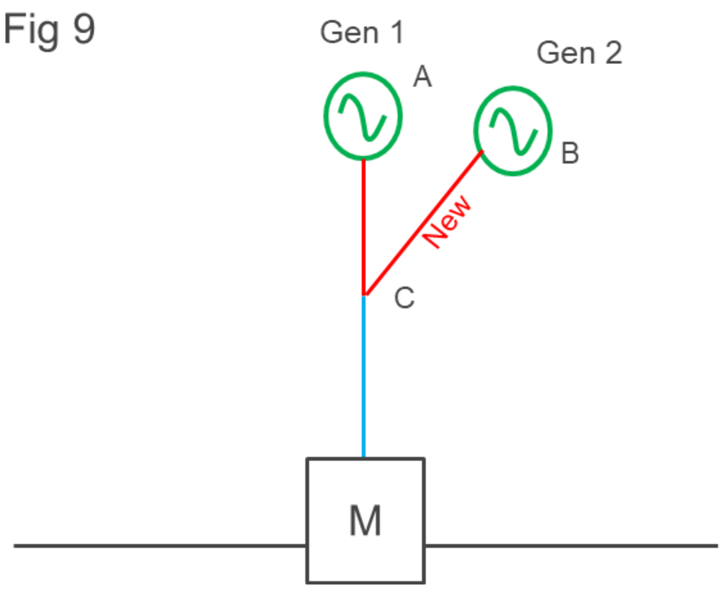
In Figure 8, it was clear that circuit AM would fall within the Connection Exclusion as it was built for and served purely Generator 1. Workgroup members agreed that if substation M already existed then local substation charges paid by Generator 1 would be outside the Connection Exclusion as they would be considered pre-existing, but if it were built to connect Generator 1 to the existing network then it would fall within the Connection Exclusion.

The Workgroup discussed whether the treatment of circuit AM would change if:
(a) final demand; or
(b) storage were to connect at node A.

One Workgroup member suggested that storage was treated as a Generator within the CUSC, therefore in case (b) this would not change the status of AM for Generator 1, but if final demand connected then the "system" should be redefined to include AM within it and therefore charges paid relating to AM by Generator 1 would cease to be in the Connection Exclusion. The reason for this was that final demand was not a "producer" and the existence of demand at A meant asset AM would cease to be required solely for connection of Generator 1 to the wider system, i.e. the existence of demand and generation at the same node was a sufficient degree of interconnectedness to trigger a difference in treatment.

Other Workgroup Members noted that storage acts equally as demand and generation, so could cause flows in the direction MA and that this should deem circuit AM to be outside the Connection Exclusion in both cases (a) and (b). It was suggested that there was also a strong case for arguing that charges paid by Generator 1 for circuit AM should remain in the Connection Exclusion even if final demand later connected at A, as the circuit AM was originally built for Generator 1.

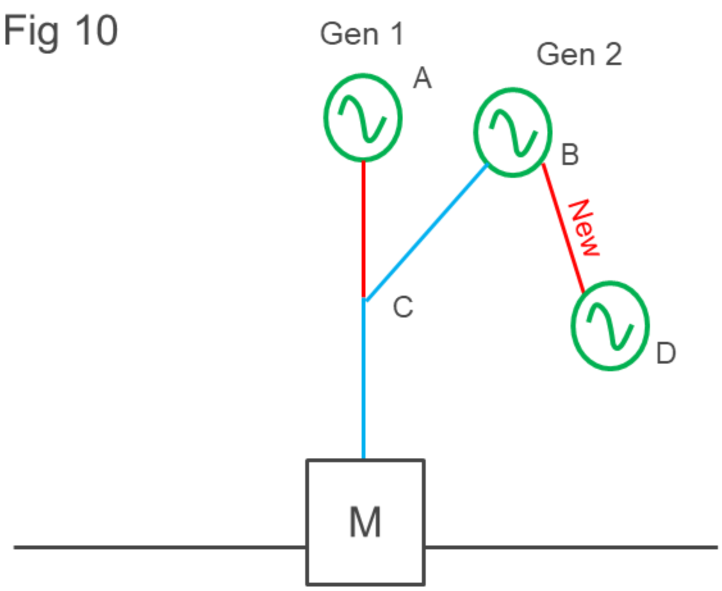
Figure 9



In Figure 9, a Workgroup member suggested that local charges paid by Generator 2 for circuit CM should be outside the connection exclusion because it was a PEA, but local charges paid by Generator 1 for circuit CM should remain inside the connection exclusion.

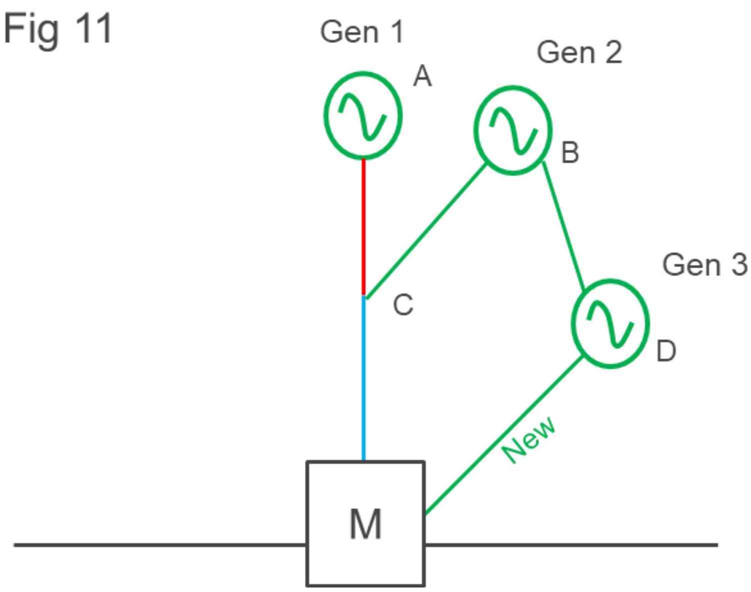
Another Workgroup member felt that CM had become interconnected by virtue of it being connected to two Generators and this was sufficient to exclude local charges paid by Generator 1 for CM to be outside the Connection Exclusion.

Figure 10



In Figure 10, a Workgroup member suggested that the principles of Figure 9 could be simply extended, but another Workgroup member deemed the circuit BCM to be interconnected and this would cause all local charges associated with Generator 1, Generator 2 and Generator 3 to be outside the Connection Exclusion.

Figure 11



In Figure 11, a Workgroup member suggested suggests that if a new piece of network DM is constructed then this changes the treatment of charges for BD, BC and CM for all generators connecting ultimately to M as regards the Connection Exclusion. This is because power from A can only flow along AC to reach demand, but power from B C and D has more than one route to demand. More than that, an amount of power already in the wider network will flow through MCBDM as well as through the busbar at M, and the fundamental premise behind the Limiting Regulation was that generators should not be paying for network that other remote users (including demand) are using even if only infinitesimally.

Therefore, the Workgroup member believes that it doesn't matter why DM is constructed: it could be for an expansion of G2 or G3, a new generator G4, or because demand has appeared somewhere in the lines connected to M and so DM is needed for additional security. The link DM causes an interconnected network to form and this takes charges for the whole of MCBDM for all generators outside the Connection Exclusion.

RIIO-2 Price Control Financial Models

The Proposer also discussed with the Workgroup a potential alternative, to utilise data that already exists within the onshore TOs' Price Control Finance Models (PCFM), that is published by Ofgem annually. The PCFM contains the annual revenue allowance, and input data on which the revenue figure is derived. One of the input data items is “GCE” (Generation connections volume driver) which represents the additional allowance (in addition to pre-agreed baseline business plan values) that onshore TOs can have by connecting additional generation into their network. The alternative option is based on the assumption that a portion of total onshore local charges is associated with non-pre-existing assets, and that this portion can be derived by comparing the GCE with the total revenue across all three onshore TOs. A Workgroup member noted that this approach would need to be considered in light of the CMA's statement, regarding the ‘degree of interconnectedness’, as the approach may not fully reflect the interconnectedness.

There was no support indicated for this potential alternative in the Workgroup's Consultation. Further, the Proposer in their response advised that this approach may require some significant assumptions to be made to ensure the data is fit for purpose in terms of use with the compliance assessment calculation, and that there would be misalignment in terms of the periods the data sets. As such, support was withdrawn for this as there would be an inherent risk in terms of data accuracy.

Section 14 - Charging Methodology Changes proposed by CMP369

- Changes to update the legal text within Section 14.14.5 and 14.17.37 to align the forecast and actual output (GO & GOA) elements used for tariff and ex-post reconciliation calculations to the new definitions

- Changes to update the legal text within Section 14.14.5 and 14.17.37 to align the forecast and actual charges (GCharge) elements used for tariff and ex-post reconciliation calculations to the new definitions

Workgroup Consultation Summary

The Workgroup held their Workgroup Consultation between 11 June 2021 – 2 July 2021 and received 10 non-confidential responses. The full responses and a summary of the responses can be found annexes 8 and 9.

The Workgroup met to discuss and consider all the responses received and noted the following trends within them:

- **Exclude both volumes and charges of LDG from compliance calculation or exclude volumes only.** Some respondents believed that excluding both the charges and the volumes was the correct interpretation of the Regulation and is in line with the direction given by Ofgem in its CMP317/327 Decision. Others believed since Distribution connected producers also contribute to overall cost recovery, it is necessary to include the charges they pay in the calculation of average tariffs. Therefore, to comply with the Limiting Regulation, the Transmission Tariff Charges paid by Large Distributed Generators should not be excluded from the calculation.

- **Specific changes to a BCA that may trigger the reclassification of assets.** It was questioned whether when an asset changes hands between physical producers, it should trigger a reclassification of assets. The Workgroup noted that a "producer" is defined in Article 2 of Directive 2009/72/EC7 as a "natural or legal person generating electricity". The Workgroup were concerned that this interpretation could lead producers to change their legal entities with the sole purpose of triggering a re-classification of their assets. The majority of Workgroup members agreed that a change of ownership should not change how network assets are treated. Further guidance was sought from Ofgem on this matter, however no further guidance could be provided.

- **Obligation on the ESO to publish the outturn value and transparently show the working for the calculation.** The majority of respondents agreed that there should be an obligation on the ESO to publish the data. However following discussions, it was agreed that a legal hook would be included in the original solution to ensure that the data was published but not placing a prescriptive obligation on the ESO.

- **TNUoS VS Transmission Charges.** The majority of respondents agreed that the legal definitions should be limited to TNUoS charges only, as it is clear within Ofgem's decision what the TNUoS charges should encompass. Other respondents felt that the use of “Transmission Charges” would be consistent with the Limiting Regulation. The Workgroup discussed this further and it was concluded that the TNUoS charges definition would be used and clearly outlined in the legal text as the Transmission Charges definition couldn’t be clearly defined. For the avoidance of doubt the Proposer subsequently included a paragraph within the draft (Section 14) legal text to provide clarity (aligned with that of the Ofgem decision) regarding those elements of “Transmission Charges” which were not considered as part of the compliance calculation. This confirmed that any element of Balancing Services Use of System charges (‘BSUoS Charges’), and Balancing Settlement Code charges (‘BSC Charges’) fall within the scope of the Ancillary Services Exclusion under the Limiting Regulation and that Transmission Connection Asset charges are also not considered for the purposes of the CUSC calculation. Following further discussion, the Workgroup decided this additional text was no longer necessary and agreed for it to be removed from the legal text drafting.
- Respondents and Workgroup Members voiced concerns around the legal interpretation and lack of transparency in the calculation, stating that there has not been enough time allocated to this modification to develop robust, consistent, practically applicable business rules and that independent legal advice is necessary to determine exactly what is and is not within the Connection Exclusion.

Workgroup Alternatives

Following review of the Workgroup Consultation responses, the Workgroup assessed the Original and the potential solutions they had previously identified. Further potential solutions were brought forward by the Workgroup in line with the themes previously identified.

In total, 22 alternative solutions were put forward to be voted on, and 19 of these became Workgroup Alternative CUSC Modifications (WACM) to be taken forwards by the Workgroup.

The WACM forms can be found in Annex 10 and a matrix table of the WACMs can be found in Annex 11. The WACMs are made up of the below variants:

Whether to *include* or *exclude* the *volumes and charges* or *volumes only* associated with *LDG* or *Distributed Generators* in/from the compliance calculation.

The Original proposal excludes both the volumes and charges of LDG from the compliance calculation, as directed by Ofgem in their CMP317/327 decision.

All of the WACMs refer to Distributed Generators rather than LDG. Workgroup members are aware that Ofgem’s direction referred to LDG, however the review of Access and Forward-Looking Charges proposed that Distributed Generation of more than or equal to

1 MW should be captured as being liable for TNUOS after its implementation date (which is not yet known). Therefore, it does not seem necessary to make a distinction between Large Distributed Generation that has to pay Generation TNUOS and other Distributed Generation that also has to pay Generation TNUoS.

For clarification, this report refers to Distributed Generators, however the Legal text developed by the Workgroup refers to Embedded Generators. The Workgroup consider these to mean the same thing.

Ten of the WACMs include the charges but exclude the volumes of Distributed Generators from the compliance calculation. This is because for the purpose of the Limiting Regulation, TNUoS charges paid by Distributed Generators are viewed to be "transmission tariff charges paid by producers"[12], but the volume associated with Distributed Generators was not "measured energy injected annually by producers to the transmission system of a Member State" [13]. Some Workgroup members did not support inconsistent treatment of the charges and volumes as this could cause distortion.

Three of the WACMs include both the charges and the volumes of Distributed Generators in the compliance calculation. This is because the output from Distributed Generators is injected, via a distribution system, onto the transmission system. Nothing in the Limiting Regulation excludes injection that is not directly onto the transmission system from the compliance calculation.

Whether to *include* or *exclude* demand transmission charges paid by generators (previously referred to as Station Demand charges in the Workgroup Consultation) in/from the compliance calculation.

The Original proposal does not include Station Demand charges paid by generators in the compliance calculation.

Ten of the WACMs would include Station Demand charges paid by generators in the compliance calculation and nine WACMs would exclude them. It was suggested by a Workgroup member that when assessing compliance with the Limiting Regulation, NGESO ensures that the 'annual total transmission tariff charges paid by producers' includes all the transmission charges paid by Generators in GB and that this should therefore include demand transmission charges paid by generators. Other members disagreed because as the calculation concerns the energy a power station injects into the transmission system, then it seems prudent to only consider the charges relating to this energy and not those associated with Station Demand.

What the appropriate timestamp should be for determining Pre-Existing Assets

Under the Original, all local assets are classed as PEA unless they are listed as enabling works in the BCA. This means local assets identified in the BCA as enabling works would fall within the connection exclusion.

[12] https://www.legislation.gov.uk/eur/2010/838/contents/adopted
[13] https://www.legislation.gov.uk/eur/2010/838/contents/adopted

Six of the WACMs use a different approach, to reflect that if a particular asset identified as enabling works had already been planned and approved to be built before the BCA was signed, then those enabling works should also be classed as PEA. This is because the intent to build those assets existed before the generator requested to connect, so those assets are not new for the purpose of connecting the generator. The following check determines if an enabling circuit is classed as pre-existing or not: Any Local assets which are not identified in the BCA as enabling works should be classed as pre-existing. In addition, at the time when a BCA is signed, any assets identified as enabling works, or which have been approved by either the TO and/or the Authority to be built will also be classed as PEA for that particular generator. The use of the Electricity Ten Year Statement was discussed by the Workgroup to identify assets that were listed as enabling works. However, it was realised that enabling works were not listed within the ETYS, and that the Authority approve the form of the ETYS rather than the contents, so the option to use the ETYS was discarded.

What constitutes sufficient ‘interconnectedness’ for charges associated with assets to not fall within the Connection Exclusion.

The Proposer believes that an appropriate level of interconnectedness is assets becoming part of the MITS and thus the Original would adopt the same definition as the MITS.

Seven of the WACMs use a “multi route method” of determining sufficient “interconnectedness”. If a local circuit connects to the MITS at two different points (not counting double circuit connections at the same location), then the local circuit will be classed as sufficiently interconnected, proving that its purpose is that of a network asset, not a connection asset, so related charges would to not be counted within the connection exclusion.

Three of the WACMs use a “generator only spurs” of determining sufficient “interconnectedness”. Only a ‘Generator only spur’ (GOS), would be classified as insufficiently interconnected, so only a generator only spur could fall into the connection exclusion of the ITC Regulation. A generator only spur is an asset that is solely required for a single specific generator concerned. This would apply equally to offshore assets and onshore assets.

Similarly, if a Generator only spur became an asset connected to and therefore used by more than one generator, and/or demand, then it would cease to be regarded as a Generator only spur. This would make it sufficiently interconnected that it is not considered as a physical asset required for connection of that generator to the transmission system. It would therefore no longer be classed within the Connection Exclusion for the purposes of the ITC Regulation.

This differs from the Original as under the original the revenue from the local circuit charge for the first connectee would be classed within the Connection Exclusion even if the asset later became interconnected such that it became connected to and therefore used by more than one generator and/or demand.

Workgroup conclusions

CMP368: The Workgroup by majority concluded that the Original, WACM7, WACM17, WACM18 and WACM19 better facilitated the applicable objectives than the current CUSC.

CMP369: The Workgroup concluded unanimously that the Original better facilitated the Applicable Objectives than the Baseline.

This Workgroup Vote can be found in Annex 12 of this report. The Workgroup is now seeking approval from the Panel that the Workgroup have met their Terms of Reference and can proceed to Code Administrator Consultation.

Legal text

Provided in Annex 13.

The Workgroup considered, as part of the definition of GB Generation Output, export volumes for distributed generation and concluded that reactive power would not be part of the calculation, and accordingly amended the legal text to include “MWh”.

What is the impact of this change?

Workgroup vote

The Workgroup met on 28 July 2021 to carry out their workgroup vote. The full Workgroup vote can be found in Annex 12. The table below provides a summary of the Workgroup members view on the best option to implement this change.
The Applicable CUSC (charging) and (non-charging) Objectives are:

CMP368 - CUSC non-charging objectives

a) The efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission Licence;
b) Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity;
c) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and
d) Promoting efficiency in the implementation and administration of the CUSC arrangements.

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

CMP369 - CUSC charging 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 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 *; and
e) To promote efficiency in the implementation and administration of the system charging methodology

*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).

Workgroup Vote

CMP368 - Assessment of the Original and WACM1 to WACM19 vs Baseline

The Workgroup by majority concluded that the Original, WACM7, WACM17, WACM18 and WACM19 better facilitated the applicable objectives than the current CUSC.

Option	Number of voters that voted this option as better than the Baseline
Original	5
WACM1	4
WACM2	3
WACM3	3
WACM4	4
WACM5	3
WACM6	3
WACM7	5
WACM8	4
WACM9	3
WACM10	3
WACM11	4
WACM12	3
WACM13	3
WACM14	4
WACM15	3
WACM16	3
WACM17	6

WACM18	5
WACM19	5

CMP368 - Best Option

Workgroup Member	Company	BEST Option?	Which objective(s) does the change better facilitate? (if baseline not applicable)
Garth Graham	SSE Generation Ltd	**WACM6**	**b), c), d)**
Grace March	Sembcorp	**WACM11**	**a), c)**
James Stone	National Grid ESO	**Original**	**a), c)**
John Harmer	Waters Wye	**WACM19**	**c)**
John Tindal	Keadby Generation Ltd	**WACM6**	**b), c), d)**
Lauren Jauss	RWE	**WACM19**	**b), c)**
Paul Jones	Uniper	**WACM17**	**c)**
Paul Youngman	Drax	**WACM18**	**b), c)**
Simon Vicary	EDF Energy	**WACM17**	**b), c)**

CMP369 - Assessment of the Original vs Baseline

The Workgroup concluded unanimously that the Original better facilitated the Applicable Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	**9**

CMP369 - Best Option

Workgroup Member	Company	BEST Option?	Which objective(s) does the change better facilitate? (if baseline not applicable)
Garth Graham	SSE Generation Ltd	**Original**	**a), d)**
Grace March	Sembcorp	**Original**	**c), d), e)**
James Stone	National Grid ESO	**Original**	**c), d), e)**
John Harmer	Waters Wye	**Original**	**d)**
John Tindal	Keadby Generation Ltd	**Original**	**a), d)**
Lauren Jauss	RWE	**Original**	**e)**
Paul Jones	Uniper	**Original**	**e)**
Paul Youngman	Drax	**Original**	**c)**
Simon Vicary	EDF Energy	**Original**	**a), d)**

When will this change take place?

Implementation date
This modification should be implemented on the 1 April 2022.

Date decision required by
A decision is required by 31 October 2021 as this will allow the definitions proposed within these modifications to be adopted by NGESO when setting tariffs for the 2022/23 charge year and for use in the ex-post reconciliation methodology to reconcile charges for charging year 2021/22 in 2022/23 if required.

Implementation approach
NGESO will use the definitions created by this modification proposal to amend charges thereby altering the amount that the Adjustment Tariff for Generators and residual charge for Suppliers recovers from 1 April 2022.

Interactions

☐Grid Code	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[14]	☐Other modifications	☐Other

CMP368 and its proposed definition changes has an interaction with CMP369 which is being proposed alongside this modification and that updates Section 14 of the CUSC to align the charging methodologies to the updated definitions.

These modifications are not expected to impact on the EBR Article 18 T&Cs[15]

How to respond

CMP368 Code Administrator consultation questions

- Do you believe that CMP368 Original proposal or WACM1, WACM 2, WACM3, WACM4, WACM5, WACM6, WACM7, WACM8, WACM9, WACM10, WACM11, WACM12, WACM13, WACM14, WACM15, WACM16, WACM17, WACM18, WACM19 better facilitates the Applicable Objectives?
- Do you support the proposed implementation approach?
- Do you have any other comments?

---

[14] If the modification has an impact on Article 18 T&Cs, it will need to follow the process set out in Article 18 of the European Electricity Balancing Guideline (EBGL – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.

[15] If your modification amends any of the clauses mapped out in Exhibit Y to the CUSC, it will change the Terms & Conditions relating to Balancing Service Providers. The modification will need to follow the process set out in Article 18 of the European Electricity Balancing Guideline (EBGL – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.

CMP369 Code Administrator consultation questions

- Do you believe that CMP369 Original proposal better facilitates the Applicable Objectives?
- Do you support the proposed implementation approach?
- Do you have any other comments?

Views are invited on the proposals outlined in this consultation, which should be received by **5pm** on **1 September 2021.** Please send your response to cusc.team@nationalgrideso.com using the response pro-forma which can be found on the CMP368 & CMP369 modification page.

If you wish to submit a confidential response, mark the relevant box on your consultation proforma. Confidential responses will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Acronyms, key terms and reference material

Acronym / key term	Meaning
ACER	Agency for the Co-operation of Energy Regulators
BEIS	Department for Business, Energy and Industrial Strategy
BCA	Bilateral Connection Agreement
BEGA	Bilateral Embedded Generation Agreement
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CMA	Competition and Markets Authority
CUSC	Connection and Use of System Code
EBGL	Electricity Balancing Guideline
ESO	Electricity System Operator
GEMA	Gas and Electricity Markets Authority
GOS	Generator only spur
ITC	Inter-Transmission Compensation
LDG	Large Distributed Generation
MITS	Main Integrated Transmission System
NPEA	Non Pre-Existing Assets
PCFM	Price Control Financial Model
PEA	Pre-Existing Assets
SCR	Significant Code Review
SQSS	Security and Quality of Supply Standards
STC	System Operator Transmission Owner Code
T&Cs	Terms and Conditions
TCR	Targeted Charging Review
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
WACM	Workgroup Alternative CUSC Modification

Reference material

- CMP317 and CMP327 Authority Decision Letter
- SSE Code Modifications Appeal 2021
- COMMISSION REGULATION (EU) No 838/2010
- Directive (EU) 2019/944 of the European Parliament and of the Council
- Decision on clarifying the regulatory framework for electricity storage: changes to the electricity generation licence (ofgem.gov.uk)

Annexes

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3	Ofgem guidance letter on CMP368/CMP369
Annex 4	Query from Workgroup member and Proposer's response (email)
Annex 5	RIIO-2 Price Control Financial Models
Annex 6	Compliance calculation spreadsheet
Annex 7	High Level Principles document
Annex 8	Workgroup Consultation Summary
Annex 9	Workgroup Consultation Responses
Annex 10	Workgroup Alternative CUSC Modification proposals
Annex 11	Alternatives Matrix
Annex 12	Workgroup Vote
Annex 13	Legal text