Workgroup Report

CMP379:
Determining TNUoS demand zones for transmission connected demand at sites with multiple Distribution Network Operators (DNOs)

Overview: This modification has been raised to update Section 14 of the CUSC to clarify how TNUoS demand zones and therefore TNUoS demand tariffs and charges should be determined for transmission-connected demand users who connect at the boundaries of multiple DNO areas.

Modification process & timetable

1. **Proposal Form** 09 September 2022
2. **Workgroup Consultation** 23 September 2022 - 14 October 2022
3. **Workgroup Report** 08 December 2022
4. **Code Administrator Consultation** 04 January 2023 - 01 February 2023
5. **Draft Modification Report** 16 February 2023
6. **Final Modification Report** 08 March 2023
7. **Implementation** 01 April 2024

Have 5 minutes? Read our Executive summary
Have 20 minutes? Read the full Workgroup Report
Have 40 minutes? Read the full Workgroup Report and Annexes.

Status summary: The Workgroup have finalised the proposer's solution. They are now seeking approval from the Panel that the Workgroup have met their Terms of Reference and can proceed to Code Administrator Consultation.

This modification is expected to have a: **Medium impact** on Generators, Transmission – Connected Demand Users, Suppliers and National Grid ESO.

Governance route	Standard Governance: 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:** Harvey Takhar, National Grid ESO Harvey.Takhar1@nationalgrideso.com Phone: 07966 808230	**Code Administrator Chair**: Catia Gomes, National Grid ESO catia.gomes@nationalgrideso.com Phone: 07843816580

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Executive summary

To update Section 14 of the CUSC to clarify how TNUoS demand zones and therefore TNUoS demand tariffs and charges should be determined for transmission – connected demand users who connect at the boundaries of multiple DNO areas.

What is the issue?

Paragraph 14.14.5 ix.) of the CUSC states that "The number of demand zones has been determined as 14, corresponding to the 14 GSP groups" with 14.15.38 then stating that "Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes." The current wording of the CUSC allows for some level of flexibility in terms of how these demand zones can be used for tariff setting purposes.

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

Proposer's solution:
To update Section 14 of the CUSC to clarify how TNUoS demand zones and therefore TNUoS demand tariffs and charges should be determined for transmission-connected demand users who connect at the boundaries of multiple DNO areas.

Implementation date:
1 April 2024

Workgroup conclusions: The CMP379 Workgroup unanimously concluded that the Original did facilitate the Applicable Objectives better than the Baseline.

What is the impact if this change is made?

This modification is expected to have a medium impact on Generators, Transmission – Connected Demand Users, Suppliers and National Grid ESO.

There will be a positive impact from updating Section 14 of the CUSC to clarify how TNUoS demand zones (and therefore TNUoS demand tariffs) should be determined for those transmission connected demand users who connect at the boundaries of multiple DNO areas. This will provide clarity on how TNUoS tariffs for such users are calculated and will ensure consistent understanding of the charging methodology for all parties involved.

Interactions

This modification has no interactions with any other modifications, codes/standards, or other industry-wide work.

This modification has no interactions with Electricity Balancing Regulation (EBR) Article 18 Terms and Conditions.

What is the issue?

Paragraph 14.14.5 ix.) of the CUSC states that "The number of demand zones has been determined as 14, corresponding to the 14 GSP groups" with 14.15.38 then stating that "Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes." The current wording of the CUSC allows for some level of flexibility in terms of how these demand zones can be used for tariff setting purposes.

At present, the 14 Transmission Network Use of System (TNUoS) demand zones are aligned with the 14 Distribution Network Operator (DNO) demand zones. Demand users pay TNUoS tariffs and charges, depending on the demand zones they fall within. For a distribution-connected user the demand zone is determined as the relevant DNO zone where the user is located. For a transmission-connected demand user, typically the geographic DNO zone determines that user's demand zone. However, if the transmission-connected user is connected to a transmission substation which also feeds multiple DNOs via its local GSP (Grid Supply Point), which therefore spans multiple DNO zones, the site is essentially located at the "boundary point" between those DNO areas. Although the current wording within the CUSC does provides a level of flexibility, under these circumstances it is not explicitly clear within the CUSC charging methodologies which demand zone this user should be allocated to.

Why change?

The latest Transmission Entry Capacity (TEC)[1] register shows that during the 2022/23 charging year several transmission-connected users (primarily energy storage systems) are expected to connect to the National Electricity Transmission System (NETS) located at a boundary point between multiple DNO areas. At present the CUSC charging methodologies do not clearly set out how the TNUoS demand zone and therefore the TNUoS demand tariffs should be determined for such a connection.

This modification seeks to update Section 14 of the CUSC to provide clarity on how TNUoS demand zones and therefore TNUoS demand tariffs should be determined for those transmission-connected demand users who connect at the boundaries of multiple DNOS. This will allow NGESO to provide clarity on how such connections will be treated and reflect them in the tariff setting and invoicing process and will also provide clarity and aid users in their understanding of network charges.

What is the solution?

Proposer's solution

It is proposed that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, the DNO with the highest local net demand Mega Watts value at that site (determined by the DNO 'week 24' demand forecast data used within the transport model) will be classed as the "predominant DNO". Subsequently, if a transmission-connected demand user is then connected to this transmission site, it will be assigned (for TNUoS tariff and invoicing purposes) the demand zone associated with the "predominant DNO" at the site. It should be noted that this demand zone may change on an annual basis

[1] ESO Data Portal: Transmission Entry Capacity (TEC) Register - Dataset| National Grid Electricity System Operator (nationalgrideso.com)

given that the "predominant DNO" is determined by local demand forecast data which may change between charging years.

TNUoS locational tariffs are derived using various data sets including the TEC register published by NGESO as well as nodal demand forecast data from the Distribution Network Operators. This data set is known as 'week 24' data and is provided by the DNOs and transmission-connected demand users to NGESO, by calendar week 24/28, under an already established process as part of Grid Code requirements. For any site where multiple DNOs connect, the relevant DNOs submit their 'week 24' nodal demand forecast, with the combined value then being the total GSP demand at the site. It is proposed that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, those nodal demand MW values within this data are to be used to identify the highest DNO local demand at that site.

TNUoS demand tariffs are calculated by means of a weighted average of all demand sites nodal costs within the same demand zone, using the 'week 24' nodal demand MW values to determine the weighting. This means that clarifying the use of a "predominant DNO" to determine which zone transmission-connected demand users at boundary points belong to, will ensure that their demand values (in the event that the Generators do indeed take demand at a triad period) can be properly accounted for when calculating and applying zonal tariffs.

It should be noted that at the April 2021 Transmission Charging Methodology Forum (TCMF), alternative solutions to the defect detailed within this modification proposal were also discussed with industry stakeholders, for example, aligning the transmission-connected demand user to a demand zone by its geographic DNO location. However, the proposer considers this alternative when assessed against the original solution would not be practical to implement for those connected at a boundary point. The identification of a geographic DNO location for a transmission-connected user may be overly complex as the Transmission Owner (TO) and DNO can have assets at the very same location, and usually share the infrastructure (cable trenches etc). In addition, the geographic boundaries can "flex" over time depending on DNOs transmission-connection/disconnection activities.

Workgroup considerations

The Workgroup convened four 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 CUSC Objectives.

Consideration of the proposer's solution

The Original solution looks to update Section 14 of the CUSC to clarify how TNUoS demand zones and therefore TNUoS demand tariffs and charges should be determined for transmission-connected demand users who connect at the boundaries of multiple DNO areas.

Following Workgroup discussions, the Proposer decided to amend their Original solution. At workgroup meeting 1 the ESO were asked to consider rather than a predominant DNO methodology (as per the original proposal), the alternative average methodology is used (average of the zonal prices be used for each DNO zone). The ESO and work group members agreed that this was a more effective solution. The average methodology solution, however, relies on the ESO's new billing system going live. Therefore, the proposed implementation date has been moved to April 2024, to allow for changes being implemented into the new billing system.

Consideration of other options

Demand Zones and GSP

A Workgroup member questioned what the current process is when there is a GSP (Grid Supply Point) in one area but supports demand from neighbouring areas which could be a different DNO area, would the demand tariffs be based on where the GSP is physically located or elsewhere. The ESO representative stated that these will be treated as the "boundary", and ESO have published a guidance note which outlines this process[2].

The ESO representative advised that demand zones are designed to align with GSP groups so the demand zone can be easily located. They explained that this information is included in the TNUoS (DCLF-ICRP) model, however clarified the following for the Workgroup:

How are demand zones selected
Demand zones are aligned with GSP groups (DNO zones). If a DNO chose to connect to a GSP which already feed another DNO, this site will become part of the "boundary" between the two DNO zones. In the TNUoS model there is a "transport" tab, where all the transmission nodes are listed. Each node contains a site code so people can easily recognise which transmission site the node represents. The full list of site codes, and the transmission sites associated with the site codes, can be found in ESO's ETYS (appendix B). Each node is associated with a demand zone (numbering from 1 to 14), showing which DNO zone the site falls into.

Allocation and how they will be split
A Workgroup member asked whether those "boundary" sites are known to users. The ESO representative explains that within the TNUoS model, those "boundary" sites can be recognised by their node names, which contain an underscore symbol ("_" followed by three letters.

Fixing the methodology for price control period

The original solution requires allocating the transmission-connected demand to the "predominant DNO zone". For tariff stability, it is suggested by some workgroup members that if this solution is taken forward, the "predominant DNO zone" should be fixed for the duration of each price control period, instead of potential "flipping" between charging years.

Zonal prices for each DNO zone

The Proposer was asked by the Workgroup to consider, rather than a predominant DNO methodology, the alternative average methodology is used (average of the zonal prices be used for each DNO zone). The Proposer stated that they have reviewed the feasibility of this option and amended their Original solution to adopt this methodology.

[2] https://www.nationalgrideso.com/document/244931/download

Legal implications of non-geographic charging

The Proposer advised the Workgroup that by proceeding with the Original approach or by the revised average methodology, there are no major legal implications from a non-geographic charging perspective.

A Workgroup member questioned if the England / Scotland and Scotland / Scotland border had been taken into consideration from a legal perspective. The Proposer confirmed that this has been considered and the following guidance would apply:

• The approach taken must demonstrate the treatment of all demand under broadly similar considerations
• Justification - Under the circumstances of connection to more than one DNO, is to be treated in this slightly different way.

How the methodology would work with different Charging sites

If a transmission-connected demand user is connected at a "boundary" site, under the proposed average methodology, it is suggested that:

1. For the purpose of calculating locational tariffs (using the TNUoS Transport model), the nodal demand associated with the transmission-connected user at this site, is "split" into multiple nodal demand each associated with a relevant GSP zone at the site; and
2. For the purpose of calculating this demand user's TNUoS liability, its triad demand is assigned evenly to relevant demand charging bases (in MW), and each is associated with the relevant zonal tariff. Where an IDNO is the transmission-connected demand user, any associated EET volumes (in MW), are also assigned evenly in the same manner. After splitting the volumes in MW and calculating the charges separately, the £ charges are added together to obtain the total liability regarding demand locational tariffs.
3. The TDR charge is not affected by this modification.

Inclusion of IDNO's

The Proposer suggested that IDNOs should also be included at connecting at the 'boundary' sites under this modification. Workgroup members agreed that IDNOs should be included as they will have connection agreements with the TO and are also transmission-connected.

Quantitative Analysis on the differences at zone boundaries

Analysis undertaken by the workgroup shows that from year 2023/24 onwards after TDR is implemented, demand tariff difference between neighbouring zones is expected to be around £2/kW, in areas where the demand tariffs are not floored at zero. At sites where potentially three DNO zones meet, the tariff difference is expected to be around £3/kW. The full analysis can be found in Annex 3.

Workgroup Consultation Summary

The CMP379 Workgroup held their Workgroup Consultation between 23 September 2022 – 14 October 2022 and received 2 non - confidential responses. The full responses along with a summary of the responses can be found in Annexes 4 and 5.

In summary:

- One respondent supported the Original Proposal and the use of the average methodology. But they suggested that the ESO should consider publishing as part of their forecasts the rates where there is volume (or proposed volume) at these nodes. This would allow customers to have greater visibility and understanding of these examples. They did not believe this needed to be codified as the impact was small and the ESO's guidance on TNUoS is fairly comprehensive.
- The other respondent supported the baseline and felt that:
  - Transmission connected loads should be related to physical location of that load as determined by the DNO licenced area. Any other solution is liable to result in the connected load potentially 'moving' transmission areas if the balance of load changes at that connection point.
  - The BSC allows import or export to be settled in Central Volume Allocation (CVA) or Supplier Volume Allocation (SVA) trading arrangements. For SVA settlements, the GSP Group must be allocated to the appropriate DNO licensed area.
  - The difference in charges may be "small", but this may change over time.
  - Locking the allocation to the geographic location of the plant/equipment minimises any opportunity for gaming or unnecessary investment 'to get across a boundary' into a cheaper zone.
- No Alternative solutions were proposed.

In reply to some of the points raised, the Proposer stated that:

- The ESO has highlighted the request for them to publish rates (where there is volume, or proposed volume at these nodes), as part of their forecasts to their Connections Team, who will look into this going forwards, but it will not form part of this modification.
- The points around minimising any opportunity for gaming refers to the DNO methodology, but as the solution is now using the blended average approach, this concern has been covered off.

Some Workgroup members disagreed with the points raised in favour of the baseline as they felt it was the electrical impact that they were trying to look at rather than the physical location. One Workgroup member also stated that they did not believe that the BSC allowed imports to be registered in CVA or SVA, if you were distribution connected and an importing metering system, you will have to register an SVA. For exports you will have the choice.

Legal text

The legal text for this change can be found in Annex 7.

What is the impact of this change?

Proposer's assessment against Code Objectives

Proposer's assessment against CUSC Charging Objectives	
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;	**Neutral**
(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);	**Neutral**
(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;	**Neutral**
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral**
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** In the view of the Proposer this Modification will better facilitate Applicable CUSC Code Objective (e), as it will update Section 14 of the CUSC by clarifying how TNUoS demand zones and therefore TNUoS demand tariffs should be determined for those transmission-connected demand users who connect at the boundaries of multiple DNO areas. This will provide clarity on how TNUoS tariffs for such users are calculated and will ensure consistent understanding of the charging methodology for all parties involved.
*The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.	

Workgroup vote

The CMP379 Workgroup met on 29 November 2022 to carry out their workgroup vote. The full Workgroup vote can be found in Annex 6. The table below provides a summary of the Workgroup members view on the best option to implement this change. The Applicable CUSC charging objectives are:

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

*The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.

The CMP379 Workgroup unanimously concluded that the Original did better facilitate the Applicable Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	5

When will this change take place?

Implementation date
This modification proposal should be implemented on the 1 April 2024.

Date decision required by
A decision is required by 30 September 2023 as this will allow NGESO time to adopt the methodology detailed within this modification proposal when determining the relevant demand zone and therefore TNUoS tariffs and charges for transmission – connected demand users located at the "boundary point" between multiple DNO areas from the 2024-

25 charging year (i.e from 1 April 2024). ESO to implement at this date due to coordination with the roll out of its new billing system.

Implementation approach

The TEC register shows that there are a small number of transmission projects (Generators) expected to connect (located at boundary points between multiple DNOs) during the 2023/24 charging year. Initial analysis performed by NGESO suggests the materiality, in terms of potential tariff difference, is within a range of £1.8/kW to £2.8/kW at each of the sites. The aggregated demand charge variation (due to difference in zones) for these projects in 2023/24, assuming they were to take full demand over the triad period, will be <£1m and therefore relatively small in the context of an overall total of £20m (including both locational and residual demand charges for transmission-connected sites) for these users. At present there are no demand only users directly connected at transmission but should this happen the connectee and their Supplier would see similar levels of charge variations due to difference in demand zones.

Taking this materiality into account and given that the CUSC isn't currently explicit with regards to how these connections should be treated, the Proposer considers it prudent to issue charging guidance to ensure industry have a clear understanding of the approach to be used for the 2023/24 charging year. The detail of this will be communicated to industry (via the TCMF) prior to the charging guidance being published on the NGESO website around the same time as the issuing of Draft 2023/24 TNUoS Tariffs in November 2021. Following which the solution created by this modification proposal would then be codified and implemented within the CUSC from 1 April 2024.

Interactions

☐Grid Code	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[3]	☐Other modifications	☐Other

Acronyms, key terms and reference material

Acronym / key term	Meaning
CVA	Central Volume Allocation
CUSC	Connection and Use of System Code
DNO	Distribution Network Operator
GSP	Grid Supply Point
DNO	Distribution Network Operator
MW	Mega Watts
NETS	National Electricity Transmission System
NGESO	National Grid Electricity System Operator
SVA	Supplier Volume Allocation
TO	Transmission Owner
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System

[3] 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 Electricity Balancing Regulation (EBR – 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.

Reference material

- April 2021 TCMF slides: "TNUoS tariff for directly-connected demand users at site with multiple DNOs"

https://www.nationalgrideso.com/document/189941/download

- CMP379 indicative aggregated demand charge variation analysis for the 2022/23 charging year:

			Total (£k)	Total (£k)
			891	**20736**
Project	**Connection Site**	**Plant Type**	**Assumed Triad Demand (MW)**	**ChargeDelta (£k)**	**total min net demand charge (£k)**
Project 1	Axminster	Energy Storage System	49.9	140	2937
Project 2	Axminster	Energy Storage System	49.9	140	2937
Project 3	Iron Acton	Energy Storage System; PV Array (	120	273	6475
Project 4	Iron Acton	Gas Reciprocating	0	0	0
Project 5	Laleham 275kV	Energy Storage System	49.9	104	2833
Project 6	Melksham 400kV	Energy Storage System; PV Array (	49.9	140	2937
Project 7	Walpole 400kV	Energy Storage System	49.9	93	2616

* based on 2021/22 final tariffs

Site	**DNO1**	**DNO2**	**DZone1**	**DZone2**	**DTariff1 (£/kW)**	**DTariff2 (£/kW)**	**TariffDelta (£/kW)**	**MinDTariff (£/kW)**
Axminster	SEP	WPD	13	14	58.8652	61.6768	2.811593	58.865203
Iron Acton	WPDSW	WPDWM	10	8	56.2368	53.96	2.276836	53.959972
Laleham 275kV	SEP	SPN	13	11	58.8652	56.7721	2.0931	56.772103
Melksham 400kV	SEP	WPD	13	14	58.8652	61.6768	2.811593	58.865203
Walpole 400kV	EME	EPN	7	9	52.4282	54.2839	1.855784	52.428151

Annexes

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3	Quantitative Analyses on the differences at zones boundaries
Annex 4	Workgroup consultation responses
Annex 5	Workgroup consultation response summary
Annex 6	Workgroup vote
Annex 7	Legal Text