Workgroup Consultation

CMP440: Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor

Overview: This CUSC modification Proposal would remove the current zero price floor from the Transmission Network Use of System (TNUoS) locational demand tariff for Final Demand, thereby re-introducing a locational investment price signal across all of Great Britian(GB). The potential for negative prices and the perverse incentive for users to consume is removed by widening the period over which consumption is measured for charging against negative tariffs.

Modification process & timetable

1. **Proposal Form** 14 August 2024
2. **Workgroup Consultation** 10 July 2025 – 31 July 2025
3. **Workgroup Report** 21 November 2025
4. **Code Administrator Consultation** 05 Dec 2025 – 30 Dec 2025
5. **Draft Modification Report** 30 January 2026
6. **Final Modification Report** 10 February 2026
7. **Implementation** 01 April 2027

Have 10 minutes? Read our Executive summary
Have 40 minutes? Read the full Workgroup Consultation
Have 60 minutes? Read the full Workgroup Consultation and Annexes.

Status summary: The Workgroup are seeking your views on the work completed to date to form the final solutions to the issue raised.

This modification is expected to have a: High impact Suppliers

Governance route	Standard Governance modification with assessment by a Workgroup	
Who can I talk to about the change?	**Proposer:** Lauren Jauss, RWE Lauren.jauss@rwe.com Phone: 07825 995497	**Code Administrator Chair**: Robert Hughes Robert.hughes3@neso.energy Phone: 07778 549357
How do I respond?	Send your response proforma to cusc.team@neso.energy by **5pm** on **31 July 2025**	

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Executive Summary

What is the issue?

The implementation of the Transmission Demand Residual (TDR) reforms in April 2023 as an outcome of Ofgem's Targeted Charging Review (TCR), especially CMP343, entailed the application of zero-price floor to TNUoS locational demand tariffs. This has removed the demand investment locational price signal differentials from zones in the north of Great Britain (GB) (currently zones 1-8).

Before April 2023, demand tariffs included a locational signal in all charging zones that was broadly equal and opposite to the generation locational signal. The removal of the TDR from the £/kW charge could have led to negative locational tariffs in some zones, potentially creating unhelpful incentives for users to use more power at times of national triad, when the system nationally may be stressed. This incentive would have existed, had the floor of zero not been imposed on the signals, because of the triad basis that underscores demand locational cost recovery.

The current methodology considers Total Peak Demand per zone for both Half Hourly (HH) and Non-Half Hourly (NHH) Demand, multiplies this by the locational zonal signal (£/kW), thus creating a zonal revenue requirement. It then looks at what the forecasted revenue recovered from HH demand would be for that zone, as only HH demand is charged based on what happens over the Triad periods. The remaining revenue to be recovered from that zone is then spread across the forecasted NHH demand between the hours of 4-7pm to create a NHH Demand tariff (p/kWh).

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

Proposer's solution:

The proposed solution involves levying negative demand TNUoS charges on summed actual energy consumption (total kWh) over 4-7pm all year round for both Peak and Year-Round demand tariffs. This is a broader range of hours for half hourly customers, and the aims is to reduce the operational TNUoS signal in negative charging zones to a low enough magnitude that it is possible to remove the current zero demand floor without incentivising unhelpful behaviour at times of high national demand. For example, the reason the floor was added under baseline, is that it would otherwise have allocated credits to HH demand in zones 1-8 in relation to each site's take at time of national "triad" peak demands. These credits would probably be marked enough to incentivise extra demand at these peak times, going against a general objective to reduce total national peak demand (for example, NESO's Demand Flexibility Service is set up to do this).

If national peak demand were boosted, the total amount of generation to meet it would be increased and the extra, marginal, generation would tend to be CO2-emitting gas plant, as well as a potential adverse effect on security of supply. By widening the charge base for HH demand in negative TNUOS demand zones, the mod aims to ameliorate or remove the undesirable incentive that would otherwise arise in unfloored charges in these zones, thus allowing disapplication of the floor.

The four types of TNUoS charges currently levied on licensed suppliers include locational £/kW charges on half-hourly metered demand, locational p/kWh charges on non-half-hourly metered demand, a locational £/kW Embedded Export Tariff credit for embedded generation, and Transmission Demand Residual (TDR)charges levied on a £/site/day basis.

Distribution connected Generators and their embedded export tariff, and non-final demand (storage and power station demand, plus certain reactive compensators that exhibit demand) are not included in the scope of this modification (so, their locational tariff elements are proposed to remain "floored" at zero), as they will be considered separately by Ofgem. The proposer believes the changes should apply to Final Demand (including electrolysers, where they are categorised as final demand, which is their default treatment).

Implementation date: 01 April 2027

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

A formal Alternative Request for a code modification was raised by a Workgroup member. This alternative proposed that for TNUoS zones where the total demand locational signal is negative, locational TNUoS is converted into a p/KWh figure and charged across total year-round demand. To reduce the number of additional tariffs created, (and because both are charged on the same basis) a single common rate is calculated for NHH and HH.

Additionally, some further ideas for an alternative were raised by a Workgroup observer. The essence of these ideas is that embedded demand of significant size along with transmission connected demand and DNO GSP's should all be charged in the same way as generation. As there are significant implications for DNOs and embedded Generators among other issues in these ideas, they go beyond the scope of the original modification proposal. This is confirmed by both the Code Administration team and the NESO legal team.

What is the impact if this change is made?

Suppliers and directly connected demand users will see, from 1st April 2027, a change in their exposure to TNUoS for their final demand type customers, via a change in the demand locational charge element in zones to the North of Britain. The proposal retains the triad charging basis for the demand locational charge element in zones that have a positive charge. Suppliers will also see a change to the TDR charge element in each band, as the allowing, if this mod is approved, of the negative charge element to pass through as a credit in relation to northern customers, instead of zero as per baseline, would mean that the TDR values, which are locationally-invariant but which do vary by band or class of demand customer, would need to rise in response.

Interactions

It is noted that this modification should be consistent with the principles of the Security and Quality of Supply Standards (SQSS). The modification has its roots in the discussions of this change concept at the TNUoS charging task force, the last meeting of which was 30th May 2023; this modification was raised after that. The modification excludes non-final demand from its scope, so that non-final demand would continue to be billed in terms of the demand locational as now (and would continue to be exempt from the TDR).

Proposer's Reasoning for Excluding Non-Final Demand from Original Proposal

Widening the charging periods to include more hours as a proxy for Triad consumption may lead to capturing Generator consumption, including storage. The proposer considers this would be inappropriate as the derived p/kWh tariff is based on the assumption that the consumer adheres to a typical consumption profile. If a typical user consumption profile is applied to non-final demand consumers, it would not be a good proxy for their Triad consumption. Therefore, a different profile and/or approach would be required. Non-Final demand users might each need a number of different proxy profiles resulting in a number of different p/kWh tariffs. This could be quite complex.

If this proposal was applied to non-Final demand, it would be most impactful on storage users whose imports are most material compared to their export volumes and their TEC. The proposer notes that the Storage Sub-Group, which initially met in June 2025, will be reviewing analysis on the impact of storage on transmission network planning and are expected to develop proposals for TNUoS charges for storage, both import and export. The proposer also notes that the existing proposal, CMP405 TNUoS Locational Demand Signals for Storage, has already been raised to address the lack of locational incentives for storage due to the implementation of the demand TNUoS floor. CMP405 seeks to separate out the demand Year-Round locational signals from Peak Security locational Signals and charge (reward) Storage which imports during times other than Triads.

The Workgroup debated the issues of whether or not the scope of this code modification should be extended to include non-final demand. Some Workgroup members believed that including non-final demand would be a logical step as they felt there was insufficient reasoning to exclude these sites from the introduction of negative Demand TNUoS locational signals. The proposer provided the arguments for restricting the scope to final demand, which are set out in the foregoing paragraphs of this report. Given this discussion, the

Workgroup felt that this issue should become an issue for consultation to the wider industry. This is reflected in question 11 in this consultation report.

What is the issue?

Missing Locational Demand Signal

A zero-price floor was applied to Transmission Network Use of System (TNUoS) locational demand tariffs from April 2023, removing most of the demand investment locational price signal, as a consequence of implementing CMP343 (Transmission Demand Residual Bandings and Allocation for April 2022 Implementation). This previous modification gave effect to Ofgem's decision from the Targeting Charging Review by levying TDR as a fixed annual site charge per charging band, instead of on a fixed £/kW national basis.

Before April 2023, demand tariffs included a locational signal that was broadly (subject to different charging zones for demand and generation, and subject to some finesse around the way GTNUoS (Generator Transmission Use of System) charges are broken down into components that are applied in a way that varies by generation type) equal and opposite to the generation locational signal i.e. in the same way that generation tariffs are mostly positive and in some locations negative, the opposite was true for locational demand tariffs. TDR and locational demand charges, both in £/kW, were previously added together, resulting in £/kW charges to demand that were positive in all demand charging zones. However, when the TDR was removed from the £/kW charge and started to be recovered on a different basis, the negative locational £/kW tariffs in some zones would, without the "floor", no longer have been "masked" by the positive TDR offset to them (from April 2023). Because of the triad charge being based on demand measured over a very narrow period of time, the negative charge (i.e. the credit) might have outweighed all other electricity costs in relation to each site, providing an unhelpful incentive to users by paying them to increase their consumption for those peak periods.

Hence the zero price floor on zonal demand locationals was introduced as part of the design and implementation of CMP343. The resulting loss of the locational demand signal in the north of Great Britain (GB) (zones 1 to 8, at present) was believed by some to represent an undesirable consequence, and a new defect.

WACMs were raised against CMP343 that proposed introducing regional variations to TDR charges to address this. However, Ofgem decided they had the potential to introduce a distortion to TDR. Further work was required.

Under the existing methodology, the objective of any measurement of consumption is to apportion to the expected consumption at ACS Peak. The proposal is consistent with this.

The proposer believes the current methodology considers that CMP213, also known as Project TransmiT, introduced the "Year-Round" Background scenario into TNUoS charging (with demand at Average Cold Spell ACS Peak) as a proxy for what is known as the "Economy Criterion" in SQSS (the security and quality of supply standards). In principle this takes into account the cost of constraints across the year and their impact on the need for transmission investment. A consumer's ACS Peak consumption is equivalent to generator TEC.
The proposer believes that having taken into consideration the optimal transmission build versus annual constraints costs, the Year-Round background scenario is designed to represent the optimal maximum flow scenario where 1MW of incremental demand or generation would trigger transmission build to accommodate that 1MW flow.

The Year-Round background represents ACS conditions, which is the median expected demand for the highest peak period in a single year. However, levying demand TNUoS charges on a small number of periods of peak consumption, such as Triads, is not appropriate in negative charging zones due to the reasons described above.

Project Transmit predominantly focused on generation, allocating costs associated with each background to different technologies depending on the likelihood that different generating technologies would affect required network investments in either background. Analysis by the then National Grid for CMP213 Project TransmiT TNUoS Developments (which introduced the Sharing approach), showed that a generator's Annual Load Factor generally has a linear relationship with its impact on incremental annual constraint costs. The follow-on relationship between annual constraints costs and transmission investment requirements was not demonstrated but was deemed to also be linear due to the convergence of the Long Run Marginal Costs (LMRC) and the Short Run Marginal Costs (SRMC) on average over the long term where the transmission network is planned using the cost benefit analysis. There were concerns at the time of the development and implementation of CMP213, that the ALF approach was too simplistic. However, the resulting solution essentially scales down charges to account for the shared use throughout the year of Year-Round transmission circuits across zone boundaries.

So whilst the Economy Criterion and Year-Round Tariffs are meant to represent year round constraints and resulting long term investment requirements, there has not been any analysis done to establish the relationship between a consumer's network use across the year compared with their ACS Peak network use to assess the suitability of the Year-Round Background proxy and adjust resulting tariffs accordingly.

The proposer believes it is unlikely that demand users currently "share" the network to the same degree as generators. For the moment, ACS Peak consumption remains the "right" benchmark for charging for demand against both backgrounds.

The wider the consumption measurement period, the less accurately a consumers ACS Peak Demand can be estimated for charging

The current approach for consumption is to measure metered demand:

- At Triads for half hourly (HH) customers
- 4-7pm all year for non-half hourly (NHH) customers.

For Non Half Hourly (NHH) customers, NESO uses forecasts of triad demand versus consumption 4-7pm all year to convert the £/kW tariff at ACS Peak to an equivalent p/kWh tariff over the period of measured consumption. The same conversion "factor" is used for all NHH customers in each zone, implicitly making the assumption that all NHH users in that zone have the same demand profile. This means that customers with a peakier Profile Class pay relatively less in £/kW for their ACS Peak consumption than those with a flatter profile class.

Therefore, if ACS Peak is the "right" benchmark for charging, moving to a wider measurement period is less accurate. Hence for those zones where charges are above the floor (i.e. are inherently positive), moving to a wider measurement period would be less cost reflective. However, for those zones where charges are zeroed out due to the floor, a wider measurement period would be better than essentially no measurement and no charge, or rather incentive, at all.

Why change?

Ofgem published their decision on CMP343 in March 2022, by which time they had already announced their decision to launch the TNUoS Taskforce, which was expected to review demand charges, particularly locational signals.

In their March 2024 meeting, the TNUoS Taskforce agreed there was high priority case for change to the demand locational tariff floor. They noted the importance of investment signals for demand cited in DESNZ's Second Consultation on the Review of Electricity Market Arrangements (REMA) in driving new industrial investment and economic growth in areas with high levels of renewable generation, and in ESO's Beyond 2030 report that recommended that demand for electricity be placed closer to where it is produced to reduce congestion across the system. Both were also published in March 2024.

The Taskforce also agreed with Ofgem's view, which is stated in their September 2023 Open Letter on Strategic Charging Reform, that signals sent through TNUoS should solely seek to influence the investment decisions of system users and not real-time operation. In their consideration of wider charging periods to remove the demand floor, the key questions the Taskforce noted were:

1. Should the peak charge apply to winter or to all of the year?

2. Should the year-round charge apply all day or just to 4-7pm?

3. Should positive and negative demand charges be charged differently i.e. should the existing methodology for positive demand charges be retained?

4. What should the methodology be for conversion from £/kW charges to p/kWh? (Noting that it may have a practical impact on the above design choices)

What is the solution?

Proposer's Initial solution:

The proposed solution is for negative demand TNUoS charges to be levied on actual consumption over a broader base of hours for both Peak and Year-Round demand tariffs in order to reduce the operational TNUoS signal and to remove the current zero demand floor. A wider charging period reduces, if not removes, the probability that negative locational TNUoS charges outweigh all other delivered electricity costs to consumers during those periods over which TNUoS is levied. Initially it was proposed that a conservative approach should be taken to the conversion from £/kW to p/kWh equivalent tariffs so that charges did not over-incentivise demand users to locate in negative charging zones.

The four types of TNUoS charge that are currently levied on licensed suppliers are:

1. Locational £/kW charges levied on half hourly (HH) metered demand as "Chargeable Demand Locational Capacity" over the Triad periods
2. Locational p/kWh charges levied on non-half hourly (NHH) as "Chargeable Energy Capacity" annual consumption between 4pm-7pm daily throughout the year
3. A locational £/kW Embedded Export Tariff (EET) credit for embedded generation over the Triad periods
4. TDR (Final Demand only) levied on a £/site/day basis, with pricing bands for different ranges of total annual consumption.

As SMART meters continue to be rolled out and the Market Wide Half Hourly Settlement programme is implemented, an increasing number of customers who are currently TNUoS-settled on a NHH basis, will move to being HH-settled customers in TNUoS terms. This is reflected in the table below:

Domestic Premises Indicator	Connection Type Indicator	Current Measurement Class (non-MHHS)	Charging Arrangement Pre- MHHS Transition	Charging Arrangements post MHHS Transition
Domestic (T)	W (Whole Current); L (LV with Current Transformer); H (HV with Current Transformer) or E (EHV with Current Transformer)	A	Chargeable Energy Capacity	Chargeable Energy Capacity
		F	Chargeable Energy Capacity	Chargeable Energy Capacity
		C	Chargeable Demand Locational Capacity	Chargeable Energy Capacity
	U (Unmetered)	B *	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
Non-Domestic (F)	W (Whole Current)	G	Chargeable Energy Capacity	Chargeable Energy Capacity
		A	Chargeable Energy Capacity	Chargeable Energy Capacity
	L (LV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		A	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
	H (HV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		A	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
	E (EHV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
	U (Unmetered)	D	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity

Chargeable Demand Locational Capacity = Triad
Chargeable Energy Capacity = 4pm – 7pm

Yellow highlight shows change in TNUoS charging as a result of CMP430

All 1-3 locational tariffs above are currently subject to a zero-price floor.

Generators are also currently liable for Demand TNUoS if they consume over the charging period. If this is widened, the current arrangements would start to capture generator consumption. This would not be appropriate, as consumption over the wider charging period would not be a good proxy for assuming an increased amount of consumption would occur during the peaks, as obviously the opposite is true.

TNUoS charges for distribution connected generators and storage demand are not intended to be in scope of this modification, as these are to be considered separately by Ofgem with recommendations from the Distributed Generation Sub-group of the TNUoS Taskforce, and by the new Storage TNUoS Sub-group. The EET described in 3 above is similarly out of scope of this proposal.

The proposer therefore believes that Final Demand is a suitable categorisation of existing network users to which the following proposed changes should apply.

The proposer also believes that the locational signals that this modification re-introduces should apply to electrolysers as an important future source of demand that can respond to long term locational cost signals to some extent Electrolyser demand will be included in the definition of Final Demand (see "discussion on Electrolysers" section below).

Therefore, initially it was proposed that:

- The zero price floor be removed for Final Demand for negative Peak Tariffs and those negative charges are levied on both HH and NHH metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year i.e. in the same way as NHH consumption is currently charged.
- The zero price floor be removed for Final Demand for negative Year-Round Tariffs and those negative charges are levied on both HH and NHH total annual metered energy consumption.
- The corresponding negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the ratio of forecast metered consumption over the relevant period assuming a baseload consumption profile. In this way the negative charge will always be based on an underestimate of ACS Peak consumption

Updated Proposer's solution

The proposer decided to amend the Original solution so that:

- Both Peak and Year-Round tariffs would be levied 4-7pm all year for both half hourly and non-half hourly customers in negative charging zones; and
- Negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the forecast total GSP metered consumption over the charging period divided by total GSP peak consumption (i.e. using the weighted average profile, instead of assuming a baseload profile for all).

The proposer also noted that following transition to Market Wide Half Hourly Settlement, the classification of customers as half hourly and non-half hourly becomes no longer appropriate. Any reference in this modification to half hourly customers means those customers on which TNUoS charges are levied based on chargeable demand locational capacity, and references to non-half hourly customers mean those customers on which TNUoS charges are levied based on chargeable energy capacity.

Reason for levying both charges 4-7pm All Year

The Workgroup considered the new tariff tables that would be required for the initial Original proposal. Currently, under the Baseline CUSC, only two columns are required per GSP zone: one £/kW tariff levied over triad for half hourly customers and one p/kWh tariff levied over 4-7pm all year on non-half hourly customers. However, under the initial Original proposal, four additional columns (six in total) would have been required to account for charges in negative charging zones. The additional columns are:

1. p/kWh Peak tariff levied on half-hourly customer consumption 4-7pm all year
2. p/kWh Year-Round tariff levied on half-hourly customer consumption all periods all year
3. p/kWh Year-Round tariff levied on non-half-hourly customer consumption all periods all year
4. £/kW total tariff levied at triad on non-final demand (which is different to final demand tariff levied at triad when the Peak tariff only is negative)

The proposer considers the new tariff tables to be highly complex for industry parties to understand and use and believes that simplifying them would significantly improve the solution. If both Peak and Year-round were levied on the same basis, there would be no reason to split out the two tariff elements and charge them separately, and there would be fewer permutations of charges since there is no need to consider the scenario where one tariff element is positive and the other is negative.

The updated Original solution would therefore only require a total of three columns of different tariffs:

1. £/kW total tariff levied according to their take at triad half hours, on half-hourly customers and non-final demand in positive charging zones
2. p/kWh total tariff levied on half-hourly customer consumption in negative zones 4-7pm all year
3. p/kWh total tariff levied on non-half-hourly customer consumption in both positive and negative zones 4-7pm all year

The proposer had also further considered whether there is a case for charging Year-Round to demand in the same way as it is charged to generation, i.e. all year, and decided that there is not. Generation is charged on the basis of Transmission Entry Capacity (TEC), and Generation Year-Round charges are scaled down to different degrees by Annual Load Factors (ALF) to account for the fact that the network is shared throughout the year with other technology classes. However, demand sharing does not feature as a concept in the methodology and existing positive charges are levied based on triad demand, or derived from forecast triad demand, as a proxy for generation TEC, and sharing is not applied. Therefore, the proposer has concluded that charging all users the Year-Round tariff 4-7pm is indeed better than levying on consumption all year because the measurement of consumption for these purposes seeks to establish a parallel for TEC, not ALF. The proposer believes that consumption measured 4-7pm will be a better proxy for triad consumption which is the basis for levying both tariffs.

Reason for Using the Weighted Average Profile instead of assuming baseload

The proposer considered whether it was better to be conservative or not when using 4-7pm consumption as a proxy for triad consumption. If all demand is assumed to be baseload, the number of customers that are "over-incentivised" to locate in negative charging zones would be minimal. This means a relatively low p/kWh tariff is derived that assumes the rate of offtake during the charging period is the same as the rate of offtake during triad. If this approach is taken, then only those consumers with a higher forecast rate of average offtake across the 4-7pm period all year, compared with their offtake during the Triad, would be over-incentivised.

The proposer concluded that whilst being conservative and providing some incentive was better than no incentive under the baseline floored approach, the best approach would be to use a best estimate and not a conservative view. This is because the proposer concluded that under-incentivising is as undesirable as over-incentivising, and an average approach balancing over- and under-incentivisation would minimise the average error.

Summary of Charging Periods

Table 1 - Current Baseline Charging Periods for Final Demand

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
Peak	Triad	4-7pm all year	Zero	Zero
Year Round	Triad	4-7pm all year	Zero	Zero

Table 2 - Initial Original Proposal's Charging Periods for Final Demand

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
Peak	Triad	4-7pm all year	**4-7pm all year**	**4-7pm all year**
Year Round	Triad	4-7pm all year	**All year**	**All year**

Table 3 - Updated Original Proposal's Charging Periods for Final Demand

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
Peak	Triad	4-7pm all year	4-7pm all year	4-7pm all year
Year Round	Triad	4-7pm all year	**4-7pm all year**	**4-7pm all year**

Workgroup considerations

The Workgroup convened 8 times to discuss the identified issue within the scope of the defect, develop potential solutions, and evaluate the proposal in relation to the Applicable Code Objectives.

The proposer presented their solution to the Workgroup, outlining that the modification has resulted from the TNUoS Taskforce. One Workgroup member queried the involvement of the Taskforce in CUSC modifications; the proposer noted support from Taskforce members for this proposal but advised that not all members had unanimously agreed with all the suggested modifications.

Background Analysis

The proposer highlighted that based on analysis by LCP Frontier in 2023, the TNUoS Taskforce had concluded that there was no case for change to replace or add additional TNUoS Backgrounds, because the existing backgrounds based on Average Cold Spell (ACS) Peak winter demand periods were representative of the network flows that drive network expansion for most circuits. There was a case for adjusting or updating the assumed generation scaling factors for Interconnectors and Pumped Storage in those existing backgrounds.

Frontier Economics had used a network model to analyse network flows for the FES System Transformation scenario for 2025. They derived sets of generation scaling factors. These reported the percentage of circuits for which those scaling factors recreated network flows that were within 90% of the peak flow in their model, i.e. the percentage of the network for which that generation configuration drives expansion. It is worth noting that the current Year-Round scaling factors are based on the level of generation accommodated through an optimal level of transmission build and constraints. However, the LCP Frontier analysis examines maximum (not optimal) network flows without constraints. So it would be expected that generation scaling factors would be higher in the LCP Frontier analysis compared to the existing Year-Round Background.

The updated “Round 1” Background that LCP Frontier derived is very similar to the current Year-Round Background which includes the locational distribution of consumer demand at over 50GW (similar to Winter ACS Peak). The Round 1 background is the best configuration that represents the network conditions that drive expansion for the most circuits, and this Background drives expansion for 59% of circuits.

The updated “Round 2” Background that LCP Frontier derived is very similar to the current Peak Background which also includes the locational distribution of consumer demand at over 50GW (also similar to Winter ACS Peak). The Round 2 background represents the network conditions that drive expansion for an additional 8% of circuits i.e. Round 1 and Round 2 together represent the conditions that drive expansion for 67% of the network.

Frontier derived a third, “Round 3”, background which further represents the network conditions that drive expansion for an additional 9% of circuits. It is only in this third background representing an additional 9% of circuits that demand is low, at 26.5GW. This analysis calls into question the assertion that peak network flows mostly occur at low demand. There could well be significant overlap between Round 1 and Round 3 Backgrounds in similarly driving network expansion, but this requires further analysis.

The retention of the existing Backgrounds with Winter ACS Peak conditions as still being largely valid in representing the conditions that drive most network expansion is a key driver for the proposer considering that demand TNUoS charges should continue to be based on demand at Triad as the equivalent of generator TEC.

Table 4 - LCP Frontier's analysis of the degree to which Backgrounds represent maximum network flows

	Current backgrounds		Most representative backgrounds (2025, NGESO FES ST scenario)		
Technology	*Peak*	*Year-round*	*Round 1*	*Round 2*	*Round 3*
Biomass	88%	27%	68%	68%	3%
OCGT	88%	0%	0%	77%	0%
CCGT	88%	27%	21%	95%	0%
Hydro	88%	27%	64%	64%	0%
Interconnectors	0%	100%	48%	59%	-80%
Nuclear	88%	85%	100%	100%	100%
Wind Offshore	0%	70%	87%	4%	87%
Wind Onshore	0%	70%	81%	4%	77%
Pump Storage	88%	50%	0%	58%	-61%
Demand (MW)	52,417	52,417	50,547	50,770	26,508
Individual % represented	32%	33%	59%	27%	15%
Cumulative % represented	32%	43%	59%	67%	76%

Current Peak and YR scenarios do not provide a very good representation for over half of the network.

Similar to YR

Similar to peak

Initial discussion on Converting the £/kW Tariff to p/kWh for wider charging periods

The proposer presented the current approach to converting the tariff for NHH customers in positive zones from £/kW to p/kWh. The proposer explained that the p/kWh tariff is set so that it collects the same amount of revenue from NHH customers in each GSP group as it would if the charge was levied based on consumption at triad.

This calculation is laid out in CUSC Section 14.16.2 as follows:

$$\frac{p}{kWh} Tariff = $$

$$\frac{NHH\ GSP\ Group\ Demand\ at\ Triad \times \frac{£}{kW} Tariff}{Measured\ NHH\ GSP\ Group\ Demand\ 4\text{–}7pm} \times \frac{100p}{£}$$

So, for example, in Zone 13, GSP Group H, the Southern HH Demand Tariff is £7.65/kW for 2025/26. We need to consider the forecast average MW offtake as per the table below to calculate the p/kWh tariff needed to deliver the same revenue that would be collected if demand was levied on triad consumption:

Period	Hours of measure-ment period	Forecast Average Demand Group H	Forecast Actual Energy Consumption
Triad	**1.5hrs**	3020MW	-
4-7pm All Year	3 x 365 = **1095hrs**	2140MW	2140MW x 1095hrs = **2,343,300MWh**
All Year	24 x 365 = **8760hrs**	1820MW	1820MW x 8760hrs = **15,943,200MWh**

If demand is measured based on consumption 4-7pm, the calculation is as follows

Output from TNUoS Transport and Tariff Model

$$\frac{p}{kWh} Tariff = \frac{3020MW \times \frac{£7.65}{kW} \times \frac{1000kW}{MW}}{2140MW \times 1095hrs \times \frac{100p}{£}} = 0.099\text{p/kWh} = \frac{3020MW}{2140MW} \times \frac{\frac{£7.65}{kW} \times \frac{100p}{£}}{1095hrs}$$

The important ratio is demand at triad vs average demand during the measured consumption period when converting tariffs from £/kW to p/kWh

Fixed data components (in black font)

The proposer highlighted the challenge of converting the current £/kW tariff to p/kWh for half hourly customers (required due to levying charges over a wider period of consumption). One Workgroup member suggested using a function of Distribution Charges. They discussed aligning the model more with the Generation model instead of converting it to p/kWh. They proposed using Connection

Capacity to calculate ALFs instead of TEC. Additionally, they queried if TNUoS could be modified to allow DNOs to pay for demand TNUoS and then feed this cost back to suppliers through the DUoS models.

One Workgroup member queried if negative charging was less of an issue for non-half hourly customers. The proposer noted that the number of non-half hourly customers will reduce with the introduction of Market Wide Half Hourly Settlement. They also advised that the intention of their proposal was to have one p/kWh tariff for all Users in a particular zone. The Workgroup discussed the split between Peak and Year-Round charges, noting some circuits will be at max flow during Peak, and some at Year-Round (in the high wind scenario). The proposer noted that Peak and Year-Round tariffs represent different circuits across the network. The Workgroup discussed whether Triads should be used for the maximum capacity requirement, with one Workgroup member noting that for Generation, the calculation of negative tariffs uses a site's maximum local peaks, which is different to triad. They queried whether it was better to use this measure for positive half hourly charging rather than triad to make the solution more cost reflective. The proposer highlighted that the model should attempt to represent peak demand for the whole system and everyone's contribution to it so advised that they thought triad was the right measure to use, noting that Demand triads should be the maximum system capacity at any one particular time.

Initial discussion on electrolysers

The proposer presented that electrolysers are an important future source of demand that is expected to be able to respond to long term locational cost signals to some extent and noted that it is not clear at this stage whether electrolyser demand will be included in the definition of Final Demand. The proposer felt that if excluded, the scope of changes under this modification should be revisited to include electrolysers. The Workgroup discussed Electrolysers, with one Workgroup member noting that clarity was required as to whether electrolyser Demand will be included in the definition of Final Demand. The NESO representative agreed to confirm this and to look into whether they should also be subject to a locational signal. She advised that CUSC definitions final demand in Section 11 thus:

"Final Demand" Means electricity which is consumed other than for the purposes of generation or export onto the electricity network"

"Final Demand Site" Shall mean;

1. For Users with a Bilateral Connection Agreement, a Single Site which has associated Final Demand, except Single Sites which are for; a. Users who own or operate a Distribution System, or b. Interconnector Users, or c. Users of a Non-Final Demand Site with a valid Declaration

2. For Users with a Bilateral Embedded Generation Agreement or BELLA, as defined as 'Final Demand Site' in the DCUSA except Non-Final Demand Site with a valid Declaration

3. For all other parties, as defined as 'Final Demand Site' in the DCUSA

The NESO representative noted, concluding, that electrolysers in general will not be storage, therefore NESO would treat them as final demand and they would be subject to locational demand signals. If an electrolyser is a part of a pure seasonal electricity storage facility, it would declare itself as such and would, presuming such declaration had been accepted as valid, then comprise non-final demand.

The Workgroup noted that the issue of whether Electrolysers should be liable for levies was an Authority/DESNZ policy matter, as levies are defined in legislation.

It was noted that electrolysers are by default treated as any other final demand but are eligible to participate in the EII scheme which offers 100% discounts on green levies/ capacity market payments, and the NCC scheme which offers 60% discounts on grid charges including BSUoS and TNUoS[1]. The government have also committed to exempting electrolytic hydrogen production from CCL payments. The proposers of the Original and Workgroup Alternative Request 1 met with Department of Business and Trade that confirmed in principle they would be supportive of industry being able to separate out TNUoS locational credits from their British Industry Supercharger discount and therefore retain 100% of the locational benefit. However, there was no discussion as to how this could be implemented in practice and evidencing this would require an electrolyser customer to receive separated locational and residual TNUoS invoice line items from their suppliers.

[1] The Industrial Strategy in June 2025 has confirmed that the support available through NCC scheme will rise from 60% to 90%. Clean Energy Industries Sector Plan - GOV.UK

Analysis on impact of the solution on customers

Deriving Proposed Tariffs

The proposer discussed with the Workgroup the current approach in deriving pence per kWh (p/kWh) tariffs as defined in the baseline legal text in CUSC Section 14.16.2. The Proposer explained that a similar approach was proposed to be used to derive p/kWh tariffs in negative zones.

The proposer explained that the conversion to a p/kWh approach is done for positive NHH tariffs zone by zone. NESO provided data to show the ratios of forecast triad demand to average demand 4-7pm and average demand all year. These ratios vary slightly by zone.

The proposer noted that in the initial proposal, Peak and Year-Round charging periods would have been different in negative zones and so there would have been a need to calculate and present these tariffs separately.

However, in the current, updated, Original proposal, the Peak and Year-Round charging periods are the same, so these tariffs can be added together and a total tariff presented.

Table 5 - Current Baseline

	Half Hourly Customers			Non-Half Hourly Customers		
	Peak		Year Round	Peak		Year Round
Negative Charges	Zero	same	Zero	Zero	same	Zero
Positive Charges	Triad	same	Triad	4-7pm all year	same	4-7pm all year

Table 6 - Initial Original Proposal

	Half Hourly Customers			Non-Half Hourly Customers		
	Peak		Year Round	Peak		Year Round
Negative Charges	4-7pm all year	different	All year	4-7pm all year	different	All year
Positive Charges	Triad	same	Triad	4-7pm all year	same	4-7pm all year

Different charging period for different components

Table 7 - Updated Original Proposal

	Half Hourly Customers			Non-Half Hourly Customers		
	Peak		Year Round	Peak		Year Round
Negative Charges	4-7pm all year	same	4-7pm all year	4-7pm all year	same	4-7pm all year
Positive Charges	Triad	same	Triad	4-7pm all year	same	4-7pm all year

Same charging period for different components

Table 8 - Demand at Triad (MW) vs Average Demand Over Charging Period (MW)

Zone	Zone Name	Total Triad Demand (GW)	HH Triad Demand (MW)	NHH Triad Demand (MW)	HH 4-7pm Demand (TWh)	HH all periods Demand (TWh)	NHH 4-7pm Demand (TWh)	NHH all periods Demand (TWh)	HH Triad (MW) vs 4-7pm Demand (MW)	HH Triad (MW) vs all periods Demand (MW)	NHH Triad (MW) vs 4-7pm Demand (MW)	NHH Triad (MW) vs all periods Demand (MW)
1	Northern Scotland	1.378	389.551	988.387	0.363	2.738	0.710	3.907	1.174	1.246	1.525	2.216
2	Southern Scotland	3.167	1071.487	2095.595	0.977	6.884	1.585	8.008	1.202	1.364	1.448	2.292
3	Northern	2.325	895.982	1429.096	0.823	6.235	1.127	5.852	1.191	1.259	1.388	2.139
4	North West	3.709	1267.166	2442.124	1.145	9.272	1.820	9.537	1.212	1.197	1.470	2.243
5	Yorkshire	3.562	1409.827	2152.348	1.280	9.868	1.656	8.659	1.206	1.252	1.423	2.178
6	N Wales & Mersey	2.416	885.021	1531.242	0.823	6.256	1.177	6.151	1.177	1.239	1.425	2.181
7	East Midlands	4.373	1544.710	2827.993	1.367	9.721	2.078	11.336	1.237	1.392	1.490	2.185
8	Midlands	3.906	1321.262	2585.196	1.172	9.757	1.915	10.458	1.234	1.186	1.478	2.165
9	Eastern	5.949	1790.943	4158.227	1.659	11.438	2.889	15.853	1.182	1.372	1.576	2.298
10	South Wales	1.691	687.938	1003.189	0.660	5.038	0.818	4.604	1.141	1.196	1.343	1.909
11	South East	3.638	969.912	2668.416	0.895	6.787	1.850	10.249	1.187	1.252	1.580	2.281
12	London	3.845	2048.601	1796.421	1.970	14.932	1.666	9.633	1.139	1.202	1.181	1.634
13	Southern	5.133	1788.486	3344.933	1.703	12.252	2.462	14.095	1.150	1.279	1.487	2.079
14	South Western	2.453	597.258	1855.428	0.548	4.179	1.280	7.308	1.193	1.252	1.588	2.224

Table 9 - Proposal Charging Periods and conversion ratios

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
Negative	4-7pm all year	All year	4-7pm all year	All year
Positive	Triad	Triad	4-7pm all year	4-7pm all year

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
Negative	4-7pm all year	4-7pm all year	4-7pm all year	4-7pm all year
Positive	Triad	Triad	4-7pm all year	4-7pm all year

Demand Zone		2026/27 TNUoS Transport Model Output			Initial Original Proposal								Updated Original Proposal			
					Charging Period				Ratio for deriving p/kWh charge				Charging Period		Ratio for deriving p/kWh charge	
					HH		NHH		HH		NHH		HH	NHH	HH	NHH
		Peak (£/kW)	Year Round (£/kW)	Total (£/kW)	Peak	Year Round	Peak	Year Round	Peak	Year Round	Peak	Year Round	Peak + Year Round	Peak + Year Round	Peak + Year Round	Peak + Year Round
1	Northern Scotland	-0.72	-34.28	-35.00	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.17	1.52
2	Southern Scotland	-1.48	-23.86	-25.34	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.20	1.45
3	Northern	-3.52	-10.62	-14.14	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.19	1.39
4	North West	-0.38	-5.55	-5.93	Triad	All Year	4-7pm	All Year	Triad	1.00	1.00	1.00	4-7pm	4-7pm	1.21	1.47
5	Yorkshire	-2.49	-3.15	-5.64	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.21	1.42
6	N Wales & Mersey	-0.49	-3.23	-3.72	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.18	1.42
7	East Midlands	-1.82	1.29	-0.53	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.49	1.49	4-7pm	4-7pm	1.24	1.49
8	Midlands	-1.09	2.08	0.99	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.48	1.48	Triad	4-7pm	Triad	1.48
9	Eastern	0.46	1.87	2.33	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.58	1.58	Triad	4-7pm	Triad	1.58
10	South Wales	-6.05	8.05	2.00	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.34	1.34	Triad	4-7pm	Triad	1.34
11	South East	3.60	2.35	5.96	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.58	1.58	Triad	4-7pm	Triad	1.58
12	London	4.86	3.60	8.46	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.18	1.18	Triad	4-7pm	Triad	1.18
13	Southern	1.88	6.33	8.21	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.49	1.49	Triad	4-7pm	Triad	1.49
14	South Western	0.85	10.80	11.65	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.59	1.59	Triad	4-7pm	Triad	1.59

The proposer initially suggested considering different charging periods, specifically proposing to charge both peak and year-round from 4 to 7 PM to simplify the process. The Workgroup raised concerns about the operational impact of spreading charges over a longer period, particularly in Scotland, where it might affect demand and power prices. The Workgroup discussed the importance of moving away from the triad to provide a better operational signal and reduce costs to consumers.

Initial Proposal's Baseload Approach

The Proposer went on to discuss a baseload profile for all noting:

- Currently, the p/kWh positive tariff for NHH consumers is multiplied by ~1.4 to account for an assumed lower rate of demand during the 4-7pm-All-Year measurement period compared with Triad demand, as well as dividing this by the number of hours over which consumption is measured to arrive at a p/kWh as opposed to a £/kW tariff.
- Baseload consumers would be over incentivised to locate in negative zones if their rate of demand over the measurement period (compared to their triad demand) is higher than average, so the initial Original proposal was for a baseload consumption profile to be assumed when deriving tariffs, i.e. instead of multiplying the p/kWh tariff to account for a lower level of average rate of consumption over the charging period, a multiplier of only 1 is used.

The Workgroup considered Resulting Tariffs Using the total zonal average forecast consumption profile vs assuming a Baseload consumption profile for Negative Tariffs as below.

Table 10 – Initial Original Proposal Illustrative Tariffs for 2026/27 Charging Year

		Current Baseline Methodology (all Users)		CMP440 Original as initially proposed using assumed baseload profile						CMP440 Original initial proposal if an average consumption profile had been used					
		(no floor for illustration)		Non-Final Demand	Final Demand					Non-Final Demand	Final Demand				
		HH	NHH	HH	HH			NHH		HH	HH			NHH	
Zone	Zone Name	(Triad) £/kW	(4-7pm) p/kWh	(Triad) £/kW	Triad £/kW	4-7 p/kWh	all periods p/kWh	4-7 p/kWh	all periods p/kWh	(Triad) £/kW	Triad £/kW	4-7 p/kWh	all periods p/kWh	4-7 p/kWh	all periods p/kWh
1	Northern Scotland	-35.00	-4.87	-	-	-0.07	-0.39	-0.07	-0.39	-	-	-0.08	-0.49	-0.10	-0.87
2	Southern Scotland	-25.34	-3.35	-	-	-0.13	-0.27	-0.13	-0.27	-	-	-0.16	-0.37	-0.20	-0.62
3	Northern	-14.14	-1.79	-	-	-0.32	-0.12	-0.32	-0.12	-	-	-0.38	-0.15	-0.45	-0.26
4	North West	-5.93	-0.80	-	-	-0.03	-0.06	-0.03	-0.06	-	-	-0.04	-0.08	-0.05	-0.14
5	Yorkshire	-5.64	-0.73	-	-	-0.23	-0.04	-0.23	-0.04	-	-	-0.27	-0.05	-0.32	-0.08
6	N Wales & Mersey	-3.72	-0.48	-	-	-0.04	-0.04	-0.04	-0.04	-	-	-0.05	-0.05	-0.06	-0.08
7	East Midlands	-0.53	-0.07	-	1.29	-0.17	-	-0.05	-	-	1.29	-0.21	-	-0.07	-
8	Midlands	0.99	0.13	0.99	2.08	-0.10	-	0.09	-	0.99	2.08	-0.12	-	0.13	-
9	Eastern	2.33	0.34	2.33	2.33	-	-	0.34	-	2.33	2.33	-	-	0.34	-
10	South Wales	2.00	0.25	2.00	8.05	-0.55	-	0.18	-	2.00	8.05	-0.63	-	0.25	-
11	South East	5.96	0.86	5.96	5.96	-	-	0.86	-	5.96	5.96	-	-	0.86	-
12	London	8.46	0.91	8.46	8.46	-	-	0.91	-	8.46	8.46	-	-	0.91	-
13	Southern	8.21	1.12	8.21	8.21	-	-	1.12	-	8.21	8.21	-	-	1.12	-
14	South Western	11.65	1.69	11.65	11.65	-	-	1.69	-	11.65	11.65	-	-	1.69	-

Public

The Workgroup concluded that there was no strong support for retaining the base load approach and suggested changing the original proposal to use the forecast average profile, which is simpler and more straightforward.

Impact of the proposed changes on domestic and commercial bills

The Proposer presented to the Workgroup the impacts of the proposed change on domestic and commercial bills, providing specific examples showing how the removal of the floor and the new charging periods would affect the annual bills of customers in different zones.

Table 11 - Initial Original Proposal Impact on Domestic Bill for 2026/27 Charging Year

		Current methodology			Current methodology but no floor			CMP440 Original as initially proposed using assumed baseload profile					CMP440 Original as initially proposed using average profile				
Zone	Zone Name	Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Total Change vs Current	Total Change vs Current no floor	Locational Charge £	TDR £	Total £	Total Change vs Current	Total Change vs Current no floor
1	Northern Scotland	-	49.29	49.29	-24.61	52.05	27.44	-11.95	50.84	38.88	-21%	42%	-26.26	52.05	25.79	-48%	-6%
2	Southern Scotland	-	49.29	49.29	-16.91	52.05	35.14	-8.77	50.84	42.07	-15%	20%	-19.53	52.05	32.52	-34%	-7%
3	Northern	-	49.29	49.29	-9.05	52.05	43.00	-5.22	50.84	45.61	-7%	6%	-9.96	52.05	42.09	-15%	-2%
4	North West	-	49.29	49.29	-4.02	52.05	48.03	-2.06	50.84	48.78	-1%	2%	-4.48	52.05	47.57	-3%	-1%
5	Yorkshire	-	49.29	49.29	-3.70	52.05	48.35	-2.21	50.84	48.62	-1%	1%	-3.96	52.05	48.09	-2%	-1%
6	N Wales & Mersey	-	49.29	49.29	-2.44	52.05	49.61	-1.32	50.84	49.52	0%	-0%	-2.71	52.05	49.34	0%	-1%
7	East Midlands	-	49.29	49.29	-0.37	52.05	51.68	0.05	50.84	50.88	3%	-2%	-0.37	52.05	51.68	5%	0%
8	Midlands	0.68	49.29	49.97	0.68	52.05	52.73	0.92	50.84	51.75	4%	-2%	0.68	52.05	52.73	6%	0%
9	Eastern	1.69	49.29	50.99	1.69	52.05	53.74	1.69	50.84	52.53	3%	-2%	1.69	52.05	53.74	5%	0%
10	South Wales	1.24	49.29	50.53	1.24	52.05	53.29	2.19	50.84	53.03	5%	-0%	1.24	52.05	53.29	5%	0%
11	South East	4.34	49.29	53.63	4.34	52.05	56.39	4.34	50.84	55.18	3%	-2%	4.34	52.05	56.39	5%	0%
12	London	4.60	49.29	53.89	4.60	52.05	56.65	4.60	50.84	55.44	3%	-2%	4.60	52.05	56.65	5%	0%
13	Southern	5.63	49.29	54.92	5.63	52.05	57.68	5.63	50.84	56.47	3%	-2%	5.63	52.05	57.68	5%	0%
14	South Western	8.53	49.29	57.82	8.53	52.05	60.58	8.53	50.84	59.37	3%	-2%	8.53	52.05	60.58	5%	0%

Table 12 - Initial Original Proposal Impact on 30MW EHV Baseload commercial user bill for 2026/27 Charging Year

		Current methodology			Current methodology but no floor			CMP440 Original as initially proposed using assumed baseload profile					CMP440 Original as initially proposed using average profile				
Zone	Zone Name	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor
1	Northern Scotland	-	1.417	1.417	-1.050	1.497	0.447	-1.050	1.462	0.412	-71%	-8%	-1.307	1.497	0.189	-87%	-58%
2	Southern Scotland	-	1.417	1.417	-0.760	1.497	0.736	-0.760	1.462	0.702	-51%	-5%	-1.029	1.497	0.467	-67%	-37%
3	Northern	-	1.417	1.417	-0.424	1.497	1.072	-0.424	1.462	1.037	-27%	-3%	-0.527	1.497	0.970	-32%	-10%
4	North West	-	1.417	1.417	-0.178	1.497	1.319	-0.178	1.462	1.284	-9%	-3%	-0.213	1.497	1.284	-9%	-3%
5	Yorkshire	-	1.417	1.417	-0.169	1.497	1.327	-0.169	1.462	1.292	-9%	-3%	-0.208	1.497	1.288	-9%	-3%
6	N Wales & Mersey	-	1.417	1.417	-0.111	1.497	1.385	-0.111	1.462	1.350	-5%	-3%	-0.137	1.497	1.359	-4%	-2%
7	East Midlands	-	1.417	1.417	-0.016	1.497	1.480	-0.016	1.462	1.446	2%	-2%	-0.029	1.497	1.468	4%	-1%
8	Midlands	0.030	1.417	1.447	0.030	1.497	1.526	0.030	1.462	1.491	3%	-2%	0.022	1.497	1.519	5%	-1%
9	Eastern	0.070	1.417	1.487	0.070	1.497	1.566	0.070	1.462	1.532	3%	-2%	0.070	1.497	1.566	5%	0%
10	South Wales	0.060	1.417	1.477	0.060	1.497	1.557	0.060	1.462	1.522	3%	-2%	0.034	1.497	1.531	4%	-2%
11	South East	0.179	1.417	1.596	0.179	1.497	1.675	0.179	1.462	1.640	3%	-2%	0.179	1.497	1.675	5%	0%
12	London	0.254	1.417	1.671	0.254	1.497	1.750	0.254	1.462	1.715	3%	-2%	0.254	1.497	1.750	5%	0%
13	Southern	0.246	1.417	1.664	0.246	1.497	1.743	0.246	1.462	1.708	3%	-2%	0.246	1.497	1.743	5%	0%
14	South Western	0.350	1.417	1.767	0.350	1.497	1.846	0.350	1.462	1.811	3%	-2%	0.350	1.497	1.846	4%	0%

The Workgroup discussed the complexities of the proposed changes, including the potential for multiple permutations of tariffs. They considered ways to simplify the methodology while maintaining cost reflectivity and fairness for different customer types.

Design Components and Option choices

The workgroup discussed the different possible permutations of alternative solutions listed as follows:

<u>Charging Period</u>

- Peak 4-7pm all year, YR all year
- Peak and YR 4-7pm all year
- Peak and YR all year

<u>How much revenue to allocate to negative charging zones</u>

- Full benefit, accounting for the expected lower rate of average offtake during the charging period compared with triad
- Lower amount, not accounting for the expected lower rate of average offtake during the charging period compared with triad

<u>When to Use Negative Charging Approach</u>

- If either YR or Peak component is negative, apply to negative tariff only
- If sum of YR and Peak is negative, apply to negative total tariff
- Apply to negative and positive tariffs (i.e. adopt new consistent approach)"

<u>Customer categories for calculating p/KWh</u>

- NHH and HH tariffs are the same
- NHH and HH tariffs are different
- NHH and HH tariffs are different with further sub-division based on measurement class"

Updated Solution

Following further development of the solution, the Proposer made the following amendments:

- Negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the forecast total GSP metered consumption over the charging period divided by total GSP peak consumption (i.e. using the weighted average profile, instead of assuming a baseload profile for all); and
- Both Peak and Year-Round tariffs would be levied 4-7pm all year for both half hourly and non-half hourly customers in negative charging zones. This makes the tariff tables much less complex

Public

Table 13 - Original Updated Proposal Illustrative Tariffs for 2026/27 Charging Year

Zone	Zone Name	Current Tariff Methodology – Demand Tariffs – HH Triad £/kW	Current Tariff Methodology – Demand Tariffs – NHH 4-7 p/kWh	Current Baseline Methodology (all Users) (no floor for illustration) – HH (Triad) £/kW	Current Baseline Methodology (all Users) (no floor for illustration) – NHH (4-7pm) p/kWh	CMP440 Original Updated Proposal – Non-Final Demand – HH (Triad) £/kW	CMP440 Original Updated Proposal – Final Demand – HH Triad £/kW	CMP440 Original Updated Proposal – Final Demand – HH 4-7 p/kWh	CMP440 Original Updated Proposal – Final Demand – NHH 4-7 p/kWh
1	Northern Scotland	-	-	-35.00	-4.87	-	-	-3.75	-4.87
2	Southern Scotland	-	-	-25.34	-3.35	-	-	-2.78	-3.35
3	Northern	-	-	-14.14	-1.79	-	-	-1.54	-1.79
4	North West	-	-	-5.93	-0.80	-	-	-0.66	-0.80
5	Yorkshire	-	-	-5.64	-0.73	-	-	-0.62	-0.73
6	N Wales & Mersey	-	-	-3.72	-0.48	-	-	-0.40	-0.48
7	East Midlands	-	-	-0.53	-0.07	-	-	-0.06	-0.07
8	Midlands	0.99	0.13	0.99	0.13	0.99	0.99	-	0.13
9	Eastern	2.33	0.34	2.33	0.34	2.33	2.33	-	0.34
10	South Wales	2.00	0.25	2.00	0.25	2.00	2.00	-	0.25
11	South East	5.96	0.86	5.96	0.86	5.96	5.96	-	0.86
12	London	8.46	0.91	8.46	0.91	8.46	8.46	-	0.91
13	Southern	8.21	1.12	8.21	1.12	8.21	8.21	-	1.12
14	South Western	11.65	1.69	11.65	1.69	11.65	11.65	-	1.69

Table 14 - Original Updated Proposal Impact on Domestic Bill for 2026/27 Charging Year

Zone	Zone Name	Current methodology – Locational Charge £	Current methodology – TDR £	Current methodology – Total £	Current methodology but no floor – Locational Charge £	Current methodology but no floor – TDR £	Current methodology but no floor – Total £	CMP440 Original updated – Locational Charge £	CMP440 Original updated – TDR £	CMP440 Original updated – Total £	CMP440 Original updated – Total Change vs Current %	CMP440 Original updated – Total Change vs Current no floor %
1	Northern Scotland	-	49.29	49.29	-24.61	52.05	27.44	-24.61	52.05	27.44	-44%	0%
2	Southern Scotland	-	49.29	49.29	-16.91	52.05	35.14	-16.91	52.05	35.14	-29%	0%
3	Northern	-	49.29	49.29	-9.05	52.05	43.00	-9.05	52.05	43.00	-13%	0%
4	North West	-	49.29	49.29	-4.02	52.05	48.03	-4.02	52.05	48.03	-3%	0%
5	Yorkshire	-	49.29	49.29	-3.70	52.05	48.35	-3.70	52.05	48.35	-2%	0%
6	N Wales & Mersey	-	49.29	49.29	-2.44	52.05	49.61	-2.44	52.05	49.61	1%	0%
7	East Midlands	-	49.29	49.29	-0.37	52.05	51.68	-0.37	52.05	51.68	5%	0%
8	Midlands	0.68	49.29	49.97	0.68	52.05	52.73	0.68	52.05	52.73	6%	0%
9	Eastern	1.69	49.29	50.99	1.69	52.05	53.74	1.69	52.05	53.74	5%	0%
10	South Wales	1.24	49.29	50.53	1.24	52.05	53.29	1.24	52.05	53.29	5%	0%
11	South East	4.34	49.29	53.63	4.34	52.05	56.39	4.34	52.05	56.39	5%	0%
12	London	4.60	49.29	53.89	4.60	52.05	56.65	4.60	52.05	56.65	5%	0%
13	Southern	5.63	49.29	54.92	5.63	52.05	57.68	5.63	52.05	57.68	5%	0%
14	South Western	8.53	49.29	57.82	8.53	52.05	60.58	8.53	52.05	60.58	5%	0%

Table 15 - Original Updated Proposal Impact on 30MW EHV Baseload commercial user bill for 2026/27 Charging Year

	Current methodology			Current methodology but no floor			CMP440 Original updated				
Zone Name	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor
Northern Scotland	-	1.417	1.417	-1.050	1.497	0.447	-1.233	1.497	0.264	-81%	-41%
Southern Scotland	-	1.417	1.417	-0.760	1.497	0.736	-0.913	1.497	0.583	-59%	-21%
Northern	-	1.417	1.417	-0.424	1.497	1.072	-0.505	1.497	0.991	-30%	-8%
North West	-	1.417	1.417	-0.178	1.497	1.319	-0.215	1.497	1.281	-10%	-3%
Yorkshire	-	1.417	1.417	-0.169	1.497	1.327	-0.204	1.497	1.293	-9%	-3%
N Wales & Mersey	-	1.417	1.417	-0.111	1.497	1.385	-0.131	1.497	1.365	-4%	-1%
East Midlands	-	1.417	1.417	-0.016	1.497	1.480	-0.020	1.497	1.477	4%	-0%
Midlands	0.030	1.417	1.447	0.030	1.497	1.526	0.030	1.497	1.526	5%	0%
Eastern	0.070	1.417	1.487	0.070	1.497	1.566	0.070	1.497	1.566	5%	0%
South Wales	0.060	1.417	1.477	0.060	1.497	1.557	0.060	1.497	1.557	5%	0%
South East	0.179	1.417	1.596	0.179	1.497	1.675	0.179	1.497	1.675	5%	0%
London	0.254	1.417	1.671	0.254	1.497	1.750	0.254	1.497	1.750	5%	0%
Southern	0.246	1.417	1.664	0.246	1.497	1.743	0.246	1.497	1.743	5%	0%
South Western	0.350	1.417	1.767	0.350	1.497	1.846	0.350	1.497	1.846	4%	0%

Consideration of other options

Alternative request

An Alternative Request for a code modification was proposed. The proposer of the alternative raised some concerns that with negative credits of over £70/MWh over the peak 4-7pm in some zones, the proposer's original solution would result in a strong distortive signal for demand in Scotland to increase over or shift to a large number of peak settlement periods, and a workgroup member presented historic analysis of Elexon data to support this view.

The proposer of the alternative raised issues from the analysis in the TNUoS Task Force presentation by Frontier Economics. These highlighted that costs associated with year-round circuits are driven by periods of constraints and recommended that year-round charging move to either all demand (simple but still more reflective than charging over peak), or over periods of constraints (more reflective, but more complicated). The proposer of the alternative presented extracts from the Clean Power 30 Action Plan, highlighting that the £60bn infrastructure spend needed was economically framed as required to avoid increasing constraint costs. The proposer highlighted that ~95% of the locational TNUoS charges in negative demand TNUoS zones related to year-round circuits.

The Workgroup also discussed the original proposer's solution as a long-term investment signal. The proposer of the alternative believes that particularly for flexible demand it would result in a much-reduced signal, as most of the credit would set off against having to run over higher peak wholesale power periods to capture it.

An Alternative Request for a code modification was therefore proposed that for TNUoS zones where the total demand locational signal is negative, locational TNUoS is converted into a p/KWh figure and charged across total year-round demand. To reduce the number of additional tariffs created, (and because both are charged on the same basis) a single common rate is calculated for NHH and HH. The proposer of this alternative suggested this approach on the basis that it was:

a) More practical: it avoided introducing an operational signal that would encourage demand over peaks

b) Better aligned with the TNUoS model (it spread Year-Round circuits over year-round demand)

c) Better aligned with actual investment drivers, i.e. constraint avoidance, full year-round generation/demand modelling undertaken in the investment process.

d) Supported by external analysis completed by Frontier Economics

e) Provided a good long term investment signal for all types of demand

f) Would be simple to implement and administer; and struck an appropriate balance between complexity and cost reflectivity.

The Alternative request can be found in **Annex 03** and a slide presentation on this in **Annex 04**.

Other ideas

A workgroup observer introduced some further alternative ideas during the workgroup discussion. As there are significant implications for DNOs and embedded generators among other issues in these ideas, they go beyond the scope of the original modification proposal. This is confirmed by both the Code Administration team and the NESO legal team. This means that they would be ineligible to be proposed as an alternative for this modification. They are set out below:

They believe that TNUoS needs to have the correct signal to attract new demand into areas of high generation and that:

- The locational signal needs to attract exactly those large-scale flexible demand users that will be able to respond to both this signal as well as, from an additional and totally separate operational viewpoint, any NESO balancing service developed to utilise generated energy that would otherwise need to be constrained off the system.
- Increased demand in these areas will, in time, feed through into the ICRP TNUoS model leading to weakening both of the negative demand and of the highly positive generation locational signals there, and over time will weaken the signal for additional demand in these areas (tariff evolution).
- It is unlikely this signal would be a strong incentive for domestic customers to relocate to these areas, but increased industry in these areas would naturally do so with the increase in commercial activity and work opportunities. Any additional residential and SME demand would accelerate the above tariff evolution in these areas.
- A Transmission Operator planning network reinforcements or assessing capacity available for new connections would not need visibility of individual embedded demand customers, only the capacity and expected demand flows over each DNO connection point to the transmission network (GSP) or aggregation of these by region (GSP group).
- Due to the way the TNUoS model averages transmission tariffs for demand zones the relationship between embedded demand sites' peak demands

and the transmission network modelled zones' peaks gets skewed by DNO actions, especially where a demand zone spans multiple transmission zones.

- Constraints are an operational signal. The ICRP (Investment Cost Related Pricing) TNUoS model is on the premise of an unconstrained system, and that the charge levied represents the cost of building the necessary network (based on the TO allowable revenue from a 40-year asset write off period). Any variation to this due to that network not having been built (especially following decisions based on cost of constraints being smaller than cost of build) should not benefit or harm generators through TNUoS.

A Workgroup observer believes the most efficient way to pass on the correct locational signals is for TNUoS to be charged to the market participants connecting to, or significantly impacting, the transmission network.

- It makes sense to charge TNUoS directly for those demand customers directly connected to the transmission grid, or even, via the supplier, those embedded with a load sizeable enough to warrant direct influence by TNUoS.
- The DNO is in the best position to respond to TNUoS on behalf of embedded demand and use the investment signal within their own network development plans. For the DNO to pass this cost on (along with their own Allowable Revenue) as part of DUoS would appear to be the most efficient means to this end, assuming DUoS is performing correctly.
- This is especially important given the way the DNO model would deal with peak demands and Triads, and this would resolve most of the issues discussed at the working group regarding the most suitable charging periods to use.
- Any response from embedded demand customers (as now albeit floored) based on the TNUoS locational signal to may be counter to DNO investment plans, and inefficiencies here will lead to poorer outcomes on the transmission network.

This Workgroup observer believes that Embedded demand of significant size along with transmission connected demand and DNO GSPs should all be charged in the same way as generation:

- If the existing TNUoS ICRP model is efficient for generation then Demand TNUoS should, where possible, reflect generation TNUoS.
- Demand TNUoS tariffs would need to use the Load Factor of the connecting asset in order to correctly apply all 4 elements of the TNUoS tariff.
- TNUoS tariff should be applied to demand connection capacity or agreed capacity as appropriate. Where the tariff is negative, the average of 3 maximum demands should instead be used, consistent with generation TNUoS charging.

To facilitate such a change there would need to be a DCUSA change and potential DNO licence changes.

The Workgroup observer believes this solution:

- Simplifies the TNUoS tariff model
- Does not cause distortion through consideration of constraints
- Provides equity between generation and demand
- Addresses the defect whilst also avoiding any unwanted locational signals
- Assumes the TNUoS ICRP incremental load flow model is efficient and allows and future changes to that model to apply equally to both demand and generation.

<u>Scope of the proposed modification</u>

The Workgroup debated the issues of whether or not the scope of this code modification should be extended to include non-final demand. Some Workgroup members believed that including non-final demand would be a logical step as they felt there was insufficient reasoning to exclude these sites from the introduction of negative Demand TNUoS locational signals. The Proposer provided the arguments for restricting the scope to final demand, which are set out in the foregoing paragraphs of this report. Given this discussion, the Workgroup felt that this issue should become an issue for consultation to the wider industry. This is reflected in question 12 in this consultation report.

Draft legal text

Legal text will be drafted after the Workgroup Consultation has been completed.

What is the impact of this change?

Proposer's assessment against Code Objectives

Proposer's assessment against CUSC Charging Objectives	
Relevant Objective	**Identified impact**
(d) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	**Positive** Would re-introduce a cost-reflective incentive for demand investment and economic growth resulting from reduced network congestion and transmission investment requirements.
(e) 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** Will not impact cost recovery but will re-distribute charges between demand users according to their relative cost impact on

	the transmission system.
(f) 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;	**Positive** Would increase cost-reflectivity of transmission investment requirements.
(g) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral** No impact. Re-introduces a cost signal that was in place before April 2023.
(h) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** Reduction of the use of triads for charging and alignment of charging periods for NHH and HH customers simplifies charging.
***The Electricity Regulation referred to in objective (g) 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.*	

Proposer's assessment of the impact of the modification on the stakeholder / consumer benefit categories	
Stakeholder / consumer benefit categories	**Identified impact**
Improved safety and reliability of the system	Neutral
Lower bills than would otherwise be the case	Neutral
Benefits for society as a whole	Neutral
Reduced environmental damage	Neutral
Improved quality of service	Neutral

When will this change take place?

Implementation date

01 April 2027 (adequate time is required for suppliers to anticipate changes to customer tariffs including the default tariff cap).

Date decision required by

30 September 2026

Implementation approach

Customer consumption over which charges are levied will need to be measured over a different period, and total Wider Tariff revenue collection will change, also impacting Transmission Demand Residual charges.

Interactions

☐Grid Code	☐BSC	☐STC	☒SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[1]	☐Other modifications	☐Other

This modification should be consistent with the principles of the SQSS.

How to respond

Standard Workgroup Consultation questions

1. Do you believe that the Original Proposal better facilitates the Applicable Objectives?
2. Do you support the proposed implementation approach that targets April 2026 (subject to Ofgem's decision falling prior to 1/10/25)?
3. Do you have any other comments?
4. Do you wish to formally raise a Workgroup Consultation Alternative request for the Workgroup to consider? (or suggest the general form/idea of one)
5. Does the draft legal text satisfy the intent of the modification?
6. Do you agree with the Workgroup's assessment that the modification does not impact the European Electricity Balancing Regulation (EBR) Article 18 terms and conditions held within the Code?

Specific Workgroup Consultation questions

7. Do you agree that in negative price zones that the peak tariff element should be charged 4-7 pm all year? Should the year-round tariff be charged 4-7 all year or 24/7 all year round? Or do you believe that there is a different basis for doing this?
8. How negative can TNUoS charges be (in p/kWh) before they create a perverse incentive for users to consume, taking into account all other electricity costs? i.e. Is the charging period 4-7pm all year a sufficient duration over which to spread negative TNUoS charges?
9. Do you agree that the best approach is to use average consumer profiles to derive p/kWh negative TNUoS tariffs for demand, rather than a conservative approach to the locational incentive which assumes that consumption during the charging period is the same as at triad?

10. Should the charging periods in positive charging zones remain the same as the Baseline or be consistent with those proposed for negative charging zones?
11. What is your opinion regarding the scope of the modification proposal i.e. that there should be no change to the baseline basis of recovery of demand locationals for non-final demand?
12. Do you consider that the Workgroup Alternative Request described in this report has merit? If you do, please set out why believe this is the case. Please offer any views you may have on the other further ideas discussed at the Workgroup, if you wish.

The Workgroup is seeking the views of CUSC Users and other interested parties in relation to the issues noted in this document and specifically in response to the questions above.

Please send your response to cusc.team@neso.energy using the response pro-forma which can be found on the CMP440 modification page.

In accordance with Governance Rules if you wish to formally raise a defined Workgroup Consultation Alternative Request, to describe a potential WACM for the Workgroup to consider, please fill in the form which you can find at the above link.

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, Workgroup 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
ACS	Average Cold Spell
ALF	Annual Load Factors

BELLA	Bilateral Exemptible Large License-exempt Generator Agreement
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DCUSA	The Distribution Connection and Use of System Agreement
DESNZ	Department for Energy Security and Net Zero
DNO’s	Distribution Network Operators
DUoS	Distribution Use of System
EBR	Electricity Balancing Regulations
EII	Energy Intensive Industries
ESO	Electricity System Operator
GSP	Grid Supply Point
GTNuOS	Generator Transmission Network Use of System
HH	Half hourly
ICRP	Investment Cost Related Pricing
LRMC	Long Run Marginal Cost
NCC	Network Charging Compensation
NESO	National Energy System Operator
NHH	Non-Half Hourly
REMA	Review of Electricity Market Arrangements
SRMC	Short Run Marginal Cost
STC	System Operator Transmission Owner Code

SQSS	Security and Quality of Supply Standards
TEC	Transmission Entry Capacity
TCR	Targeted Charging Review
TDR	Transmission Demand Residual
TNUoS	Transmission Network Use of System
T&Cs	Terms and Conditions
WACM	Workgroup Alternative CUSC Modification

Reference material

- Ofgem's decision from the Targeting Charging Review
- CMP343 Transmission Demand Residual bandings and allocation for 1 April 2022 implementation:
- https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/cmp343-and-cmp340-transmission-demand-residual-bandings-and-allocation-1-april-2022-implementation-cmp343-and-consequential-changes-cmp343-cmp340
- CMP213 Project Transmit TNUoS Developments:
- https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/cmp213-project-transmit-tnuos-developments
- TNUoS Taskforce January 2024 meeting Frontier Demand TNUoS qualitative analysis
- TNUoS Taskforce March 2024 meeting high priority case for change to the demand locational tariff floor
- DESNZ's Second Consultation on the Review of Electricity Market Arrangements (REMA) in driving new industrial investment and economic growth in areas with high levels of renewable generation
- ESO Beyond 2030 report

Annexes

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3	Alternative request from Statkraft
Annex 4	Slide presentation of Alternative Request 1
Annex 5	Tariff Calculations for Alternative Request 1
Annex 6	Effective Price Signals for Alternative Request 1