ESO

Draft Final Modification Report

CMP286: Improving TNUoS Predictability Through Increased Notice of the Target Revenue used in the TNUoS Tariff Setting Process

Overview: The purpose of this modification proposal is to improve the predictability of TNUoS demand charges by bringing forward the date at which the target revenue used in TNUoS tariff setting is fixed to allow customer prices to more accurately reflect final TNUoS rates.

Modification process & timetable

1. **Proposal Form** 10 October 2017
2. **Workgroup Consultation (2)** 06 April 2022 – 09 May 2022
3. **Workgroup Report** 22 September 2022
4. **1st Code Administrator Consultation** 04 October 2022 – 25 October 2022
5. **1st Draft Modification Report** 17 November 2022
6. **1st Final Modification Report** 07 December 2022
7. **Authority Send Back Decision** 30 June 2023
8. **2nd Code Administrator Consultation** 29 November 2023 – 5 January 2024
9. **2nd Draft Modification Report** 18 January 2024
10. **2nd Final Modification Report** 26 January 2024
11. **Implementation** 30 September 2024 – Effective from 1 April 2026

Have 15 minutes? Read our Executive summary

Have 30 minutes? Read the full Second Draft Final Modification Report

Have 120 minutes? Read the full Second Draft Final Modification Report and Annexes.

Status summary: The Draft Final Modification Report has been prepared for the recommendation vote at Panel.

Panel recommendation: The Panel will meet on 26 January 2024 to carry out their recommendation vote.

This modification is expected to have a: **High impact** on Suppliers, the ESO, Transmission Owners and Consumers

Governance route	This modification has been assessed by a Workgroup and Ofgem will make the decision on whether it should be implemented.	
Who can I talk to about the change?	**Proposer:** Niall Coyle niall.coyle@eonenergy.com 07971 247658	**Code Administrator Chair:** Catia Gomes catia.gomes@nationalgrideso.com 07843816580

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Executive summary

This modification seeks to improve TNUoS predictability through increased notice of the Target Revenue (CMP286) and demand inputs (CMP287) used in the TNUoS Tariff Setting Process. It therefore provides certainty to inputs into the TNUoS charging methodology that market participants cannot forecast, thereby making the costs customers pay more reflective of the final charge. Consequently, the Proposer argues that this will reduce the risk premia charged by Suppliers to consumers.

What is the issue?

Final TNUoS tariffs are published with a notice period of only 2 months. TNUoS tariffs are set by the ESO by populating several inputs into the charging methodology models. Many of these inputs are difficult to predict and are not finalised until shortly before final tariff publication.

The Proposer argues that, in previous years, they have observed significant changes in both revenue and volume inputs between the ESO's forecasts over a short period of time. This creates uncertainty around the level of final tariffs, and results in significant changes between regions and Half Hourly (HH) /Non-Half-Hourly (NHH) Tariffs.

In the view of the Proposer, Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require. Given that market participants are trying to predict TNUoS costs as accurately as possible, large, and late changes of inputs, which significantly affect the calculation of TNUoS prices, need to be avoided.

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

Proposer's solution:

- Target Revenue to be fixed 15 months ahead of TNUoS tariffs going live.
- Minimal changes to existing tariff setting processes.

Implementation date: 31 December 2024 (Effective from 1 April 2026)

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

Alternative Solution(s)	Details	Implementation Date
WACM1	As per Original but relevant costs borne by The Company as defined in the Transmission Licence" are not locked down 15 months ahead of tariffs	As per Original

Workgroup conclusions:
First Workgroup Vote for CMP286/287: The Workgroup concluded by majority that the Original and WACM1 better facilitated the applicable CUSC Objectives than the Baseline.

Second Workgroup Vote CMP286: The Workgroup concluded by majority that the Original better facilitated the applicable CUSC objectives than the Baseline.

Panel recommendation: Panel will meet on 26 January 2024 to carry out their recommendation vote.

What is the impact if this change is made?

In the view of the Proposer, making this change will allow Suppliers to reduce the risk premia they factor into the costs they charge customers since there will be more certainty around TNUoS forecasts. However, this moves the forecast risk to the Transmission Owners, who will need to fix the inputs they provide to the ESO (for TNUoS tariff setting) further ahead of time leading to increased risk of inaccuracy.

Interactions

STC/STCP Changes
Transmission Owners will need to provide data earlier to the ESO than they do now and therefore there will be changes required to the following STCPs:

- STCP13-1 Invoicing & Payment
- STCP14-1 Data Exchange for Charge Setting
- STCP24-1 Revenue Forecast Information Provision
- Enhanced reporting requirements will be necessary to be provided from NGESO to Transmission Owners to provide visibility of variances once the Target Revenue and inputs have been set.

STCP changes were raised in the October 2023 STC Panel.

Transmission Licence Implications
The Transmission Owners will be seeking changes to their Transmission Owner licence, and these are discussed in the "Impacts on Transmission Owners" section.

Interaction between CMP343 and CMP287
The Workgroup also discussed whether or not there was interaction between CMP287 and CMP343 which introduces 4 Transmission Bands to charge the Transmission Demand Residual to transmission connected sites from 1 April 2023. The conclusion was that there was no relevant interaction between the modifications. The Proposer noted that CMP287 seeks to fix the charging base inputs for TNUoS 15-months ahead of time, including, but not limited to, the Total Gross triad Demand, Chargeable HH demand, and chargeable NHH (Non-Half Hourly) demand. CMP343 introduces a series of TNUoS fixed charges, which adds additional TNUoS charging bases. This includes the consumption for each fixed charging, and the number of sites in each fixed charge band. The CMP287 solution captures these additional charging base elements.

There is no expected impact on the EBR Article 18 T&Cs.

What is the issue?

Final TNUoS tariffs are published with a notice period of only 2 months. TNUoS tariffs are set by the ESO by populating several inputs into the charging methodology models. Many of these inputs are difficult to predict and are not finalised until shortly before final tariff publication.

Why change?

The Proposer argues that, in previous years, they have observed significant changes in both revenue and volume inputs between the ESO's forecasts over a short period of time. This creates uncertainty around the level of final tariffs, and results in significant changes between regions and Half Hourly (HH) /Non Half-Hourly (NHH) Tariffs.

In the view of the Proposer, Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require. Given that market participants are trying to predict TNUoS costs as accurately as possible, large and late changes of inputs, which significantly affect the calculation of TNUoS prices, need to be avoided.

The Proposer noted that Distribution Use of System (DUoS) charges are set with 15 months' notice and therefore argued that changing the notice period for TNUoS charges would align the CUSC with the distribution charging regime and would reduce complexity. The Workgroup also noted that on 5 May 2021, the Distribution Network Operators (DNOs)(via the Energy Networks Association) had formally sent a letter to Ofgem requesting that the 15 months' notice period required for DUoS need not apply for prices commencing 1 April 2023 and 1 April 2024 as the current 15-month notice period requires them to set prices before final determinations on allowed revenues were known. Ofgem rejected this request on 20 May 2021 and concluded that, on balance, issues associated with shortening the notice periods outweigh the benefits at this time.

However, the Transmission Owner representatives noted that there are significant differences between the two types of networks, which mean alignment of notice periods is not strictly necessary. They added that compared to distribution revenue, transmission revenue is made up of many more diverse elements, creating significantly different forecasting risk e.g. the DNOs do not have the option to bring forward large investment projects within a price control period as Transmission Owners do via the Strategic Wider Works mechanism.

What is the solution?

Proposer's solution

- Target Revenue to be fixed 15 months ahead of TNUoS tariffs going live.
- Minimal changes to existing tariff setting processes.

Workgroup considerations

The Workgroup convened 15[1] 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.

[1] Six times prior to the Modification being paused and seven thereafter.

Workgroup discussions on the proposer's solution

Interaction with CMP244

The issue of TNUoS Notice period was last raised in 2015 through **CMP244.** This sought to increase the length of the notice period for TNUoS tariffs from two months to a suggested period of 200 calendar days. The Proposer considered that **CMP244** would enable suppliers to reduce the risk premiums they add to their electricity prices, resulting in lower prices to some of their non-domestic customers. The Proposer also considered that **CMP244** would improve competition amongst Suppliers. **CMP244** was rejected by Ofgem on15 July 2016 for the following reasons:

Against Applicable Objective (a)

'On balance, we consider that a clear case has not been made that CMP244 and CMP256 would better facilitate the achievement of the relevant objectives. We therefore consider the impact on this objective to be neutral'.

Against Applicable Objective (b)

'We also note that increased over/under-recovery is likely to have a negative impact on cost reflectivity. We therefore consider that CMP244 is marginally negative against this objective.

A key question for the CMP286 and CMP287 Workgroup is to understand how modifying the allocation of risk (cost recovery/inaccuracy risk) from Suppliers to Transmission Owners will improve outcomes for consumers. The Workgroup agreed the importance of further analysis to show the benefits to consumers (via lower aggregate risk premia) of extending the notice period of TNUoS tariffs (3 to 15 months) and the need for the Proposer to address the reasons why **CMP244** was rejected.

Target Revenue and certain Inputs to be fixed 15 months ahead of TNUoS tariffs going live

How TNUoS setting process works today

Under current arrangements, each Transmission Owner (Onshore or Offshore) provides the ESO its revenue which should be collected in a charging year. The source for this revenue data is the Price Control Financial Model (PCFM), which is annually updated via a process managed by Ofgem.

This information is fixed on 25 January and used by the ESO as an input into TNUoS tariff calculations, which are set and published on 31 January each year and take effect from the following 1 April.

Separately, throughout each charging year, ESO forecast the expected chargeable demand in Megawatt per hour (MWh) (the volume to be used in the next charging year). The forecast alters as the year progresses owing to new information becoming available and can change up until final tariffs are set in January. The forecast is also an input into the demand TNUoS tariff calculation (specifically into the derivation of the 'residual' element of TNUoS).

Which inputs are changing?

The only elements of the TNUoS charges that would be fixed would be the Allowed Revenue and the Demand Charging Base. This is illustrated below:

Diagram 1

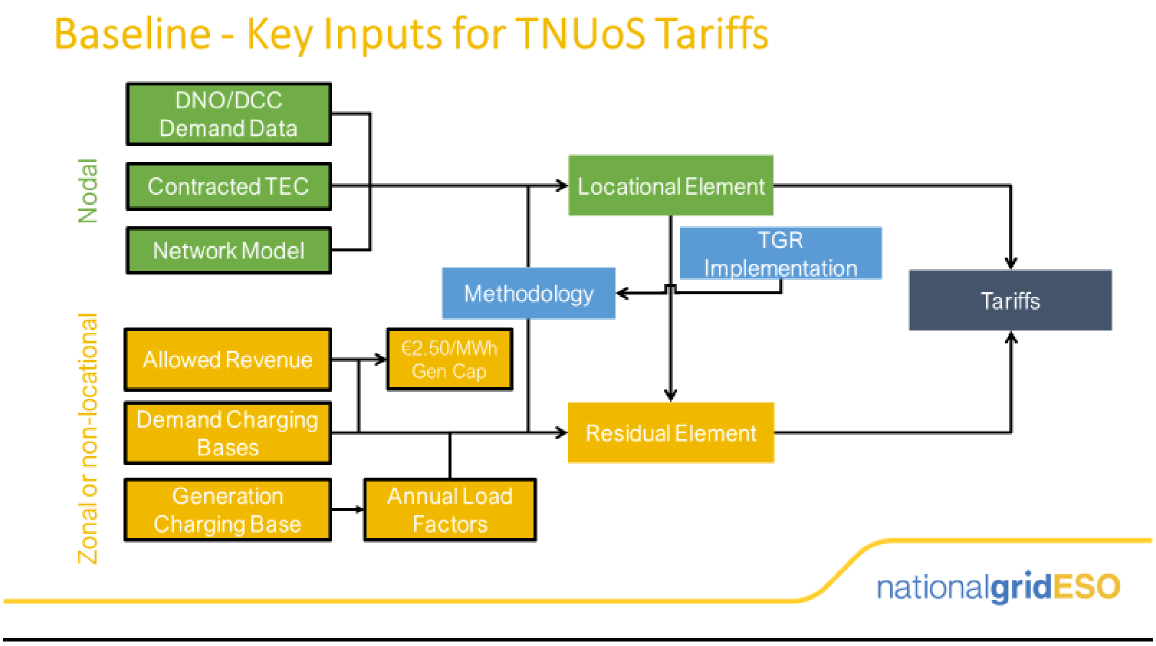
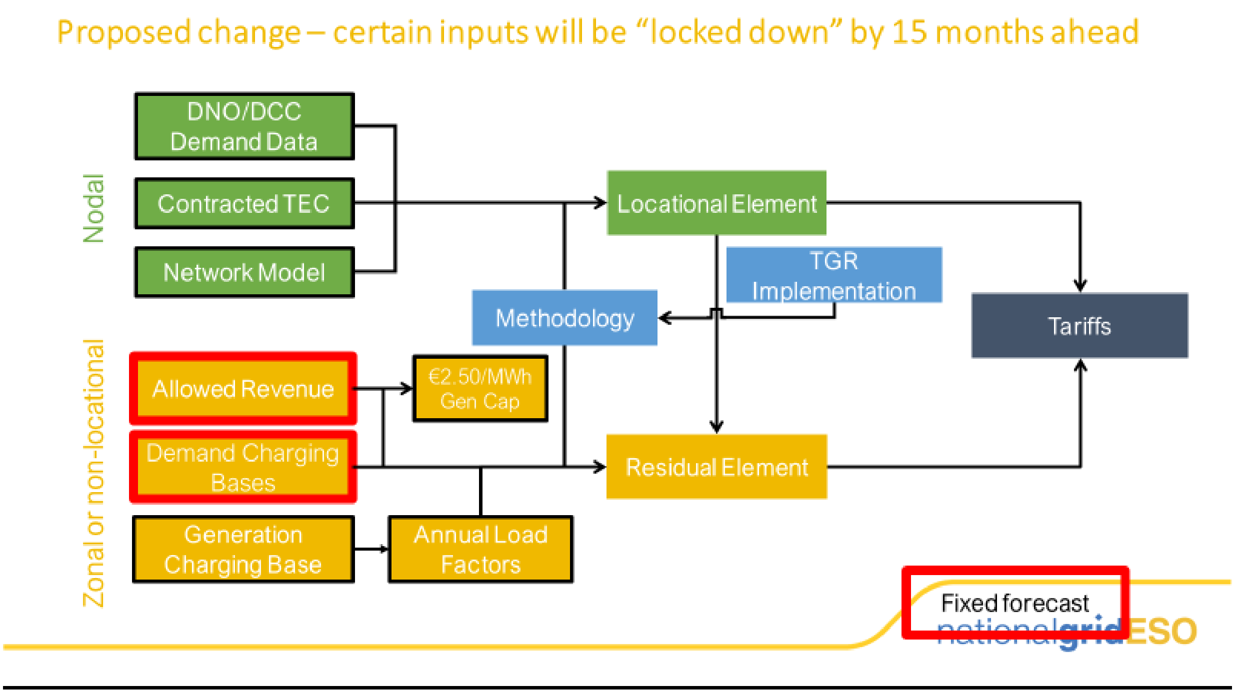


Diagram 2



The ESO Workgroup Member shared a more granular view of what this would mean in practice for the 2024/2025 TNUoS tariffs (i.e. apply from 1 April 2022). This is represented by Diagram 3 below.

Diagram 3

Baseline: Key Inputs for 2025/26 TNUoS Tariffs – refined quarterly

		March 2024	August 2024	Draft Tariffs November 2024	Final Tariffs January 2025
	Methodology	Open to industry governance			
Nodal	DNO/DCC nodal Demand Data	Initial update using previous year's data source		Week 24 updated	
Nodal	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
Nodal	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
Nodal	Inflation	Forecast	Forecast	Forecast	Actual
Zonal or non-locational	New OFTO Revenue (part of allowed revenue), other ESO pass-through	Forecast	Forecast	Forecast	NGESO best view
Zonal or non-locational	Allowed Revenue (existing TOs)	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
Zonal or non-locational	Demand Charging Bases by zones	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
Zonal or non-locational	Generation Charging Base	NGESO best view	NGESO best view	NGESO best view	NGESO final best view
Zonal or non-locational	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
Zonal or non-locational	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

- Green highlighting indicates that these parameters are fixed from that forecast onwards.

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The ESO Workgroup Member then advised that, if the CMP286 and CMP287 Original are approved, the December 2022 data will be used to calculate the TNUoS tariffs that would apply from 1 April 2024. The Proposer confirmed that in their Original proposal, the expectation is that the November annual iteration process will look at Year + 2 rather than, as now, Year + 1. However, there will still be locational variations as the Nodal inputs are not locked down.

Diagram 4

Proposal: Key Inputs for 2025/26 TNUoS Tariffs – revised timeline

		Dec 2023	March 2024 – January 2025 forecasts	Jan 2025 (final tariffs)	
	Methodology				
Nodal	DNO/DCC nodal Demand Data		Quarterly updates as per the baseline	Locked down since Draft tariffs	
Nodal	Contracted TEC				
Nodal	Network Model				
Nodal	Inflation				
Zonal or non-locational	New OFTO Revenue (part of allowed revenue), other ESO pass-through	NGESO best view for 2025/26	No change	Using the Dec 2023 data to calculate final tariffs	Fixed by 15 months ahead
Zonal or non-locational	Allowed Revenue (existing TOs)	Best view from TOs for 2025/26			
Zonal or non-locational	Demand Charging Bases (by zones), plus site bands post TDR	NGESO forecast for 2025/26			
Zonal or non-locational	Generation Charging Base		Quarterly updates as per the baseline	Finalised	
Zonal or non-locational	Generation ALFs				
Zonal or non-locational	Generation Revenue (G/D split)				

The nodal inputs are not locked down, and will still drive locational variations;
The generation and demand tariffs will still change across those quarterly forecasts

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The ESO Workgroup Member proposed an alternative to the CMP286 Original where "**relevant costs borne by The Company as defined in the Transmission Licence**" are not locked down 15 months ahead of tariffs. This is discussed in the "Workgroup Alternatives" section of this document.

<u>Proposer analysis to demonstrate TNUoS volatility</u>

The Proposer shared their analysis which included years prior to Covid to support their view that there have been significant changes and volatility in both revenue and volume inputs between the ESO's forecasts over a short period of time.

The following tables show the forecast of Target Revenue (Total to Collect from TNUoS) from the ESO's quarterly updates of the 2021/2022 Tariff forecast and the variance between forecasts.

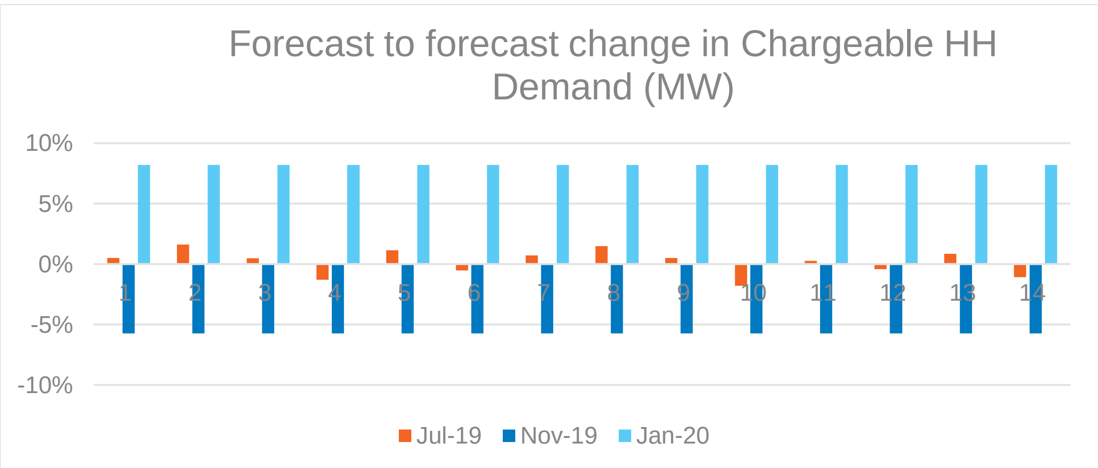
	2021/22 TNUoS Revenue				
£m Nominal	Aug-19	Apr-20	Aug-20	Nov-20	Jan-21
TO Income from TNUoS					
National Grid Electricity Transmission	1,791.3	1,754.9	1,723.9	1,919.9	1,755.3
Scottish Power Transmission	384.2	376.7	371.5	390.6	375.8
SHE Transmission	372.0	374.0	380.0	539.7	582.6
Total TO Income from TNUoS	2,547.5	2,505.7	2,475.3	2,850.2	2,713.7
Other Income from TNUoS					
Other Pass-through from TNUoS	41.4	17.4	17.5	14.4	49.6
Offshore (plus interconnector contribution / allowance)	494.3	529.9	555.8	545.6	555.2
Total Other Income from TNUoS	535.7	547.4	573.3	560.0	604.8
Total to Collect from TNUoS	3,083.2	3,053.1	3,048.6	3,410.2	3,318.5

Movement between forecasts	2021/22 TNUoS Revenue				
£m Nominal	Aug-19	Apr-20	Aug-20	Nov-20	Jan-21
TO Income from TNUoS					
National Grid Electricity Transmission		(36.4)	(31.0)	196.0	(164.6)
Scottish Power Transmission		(7.4)	(5.3)	19.1	(14.8)
SHE Transmission		2.1	5.9	159.8	42.9
Total TO Income from TNUoS		(41.8)	(30.4)	374.9	(136.5)
Other Income from TNUoS					
Other Pass-through from TNUoS		(24.0)	0.0	(3.0)	35.2
Offshore (plus interconnector contribution / allowance)		35.6	25.9	(10.2)	9.6
Total Other Income from TNUoS		11.6	25.9	(13.3)	44.8
Total to Collect from TNUoS		(30.1)	(4.5)	361.7	(91.8)

This demonstrates significant variation in the target revenue, at both indicative and final tariff setting, leading to increased volatility and unpredictability in the ESO forecasts.

The Proposer cited Half Hourly (HH) Tariff setting for 2020/2021 to illustrate the issue of demand volatility. 2020/21 was chosen as this is the latest year prior to Covid-19 impacting demand forecasting. Graph 1 shows significant variation in the HH demand charging base at both indicative and final tariff setting for 2020/2021 that market participants were not able to effectively forecast. The Proposer believes that the volatility demonstrated leads to additional uncertainty in the ESO's forecasts, which as a result could drive Suppliers to include larger risk premiums in fixed price contracts.

Graph 1



The Proposer argued that with such unpredictable variations in TNUoS tariffs, accurate customer pricing is extremely challenging, resulting in the need for Suppliers to include risk premia. The Proposer and some Workgroup Members argued that locking down the Target Revenue input into the TNUoS pricing process much earlier in the forecasting cycle removes the majority of uncertainty and should enable Suppliers to reflect the final TNUoS tariffs more accurately in customers pricing and bills through a reduced risk premia.

Reduced Risk Premia

The Proposer noted that a typical domestic or business customer, whose meter is settled on a NHH basis and agrees a two-year fixed price contract with their Supplier will have the TNUoS cost reflected within their contract rates. This will comprise of a best view forecast plus risk premia based on volatility and unpredictability of this charge for the period where final tariffs have not yet been published.

For a NHH two-year contract starting in October, TNUoS tariffs are only known for a quarter of the contracted period and the remaining three-quarters being reliant on a forecast. Therefore, to mitigate the risk of a significant variance between outturn and forecast TNUoS, Suppliers may add into their p/kWh consumer price (pence per unit) a risk premium. This premium is designed to offset the cost to the Supplier in the event that they have under-recovered TNUoS from electricity consumers against actual TNUoS costs. The Proposer of CMP286/287 believes that fixing elements of the calculations 15 months in advance of the charging year in which they would apply will reduce the volatility in TNUoS tariffs.

Some Workgroup Members have argued that a reduction in volatility will lead to a reduction in the value of the risk premia Suppliers may apply, which could reduce costs to electricity consumers. The majority of those who responded to the Workgroup Consultation (4 out of 7) agreed that this change will lead to reduced risk premia. However, some respondents (3 out of 7) argued that the case for change has not been proven; specifically, how this leads to reduced costs for consumers. Following Workgroup discussions it was noted that the retail market is competitive and that it is reasonable to assume Suppliers would pass these reductions onto consumers.

The Workgroup noted that the key is to understand the potential consumer benefit derived from a reduction in risk premia which may stem from implementation of either or both of these modifications. However, an individual Suppliers risk premia is commercially confidential and therefore on 31 May 2018, the ESO issued an open letter seeking information on the risk premia Suppliers may use to mitigate TNUoS volatility. The ESO agreed to collate, anonymised and analyse the findings and this is set out in Annex 5.

In summary, the data provided confirms that additional premiums are added by Suppliers to transmission charge tariffs to reflect the uncertainty that demand forecasts have on fixed term contracts. In addition, the analysis shows:

- Average risk premia on certain contracts would decrease based on the data provided by Suppliers, but on other contracts it would increase were either CMP286, CMP287 or both to be implemented; and
- There is a peak in average risk premia on 24-month NHH contracts which disappears if CMP286 and CMP287 were to be implemented.

The Proposer clarified that the consumer impact of CMP286 and CMP287 was previously calculated by applying live market assumptions in 2018 to anonymised risk premia data collected from Suppliers via a Request for Information. The Workgroup agreed it wouldn't be an effective use of time to obtain new risk premia data[2] from suppliers given the last one was only in 2018. However, the Proposer agreed to update the analysis by applying the latest market assumptions to test if CMP286 and CMP287 would still benefit consumers in the current market.

The revised analysis, as set out in Annex 6 of this document, uses Ofgem's retail market indicators view of domestic customers on standard variable tariffs (as at April 2022), with the proportion on fixed contracts reducing from 44% in 2018 to 31% in 2022. The annual market volumes for both domestic and non-domestic have been taken from Chapter 5 of the latest Digest of UK Energy Statistics (DUKES) Report published on 28 July 2022 using calendar year 2021 demand. Due to the impact of Covid-19 lockdowns, the total volumes have decreased by ~ 5% overall although domestic volumes are up ~ 4% and non-domestic volumes down by ~ 9%.
This revised analysis shows:

- An average annual benefit for domestic consumers of £6.2m (down from £8.5m in 2018) – this is primarily driven by the increased proportion of domestic consumers on standard variable tariffs due to the current conditions in the domestic retail market.
- An average annual benefit for non-domestic consumers of £32.7m (down from £36.0m in 2018), due primarily to the impact of Covid-19 lockdowns on non-domestic demand in 2021. The Proposer noted the limitations of the non-domestic analysis, which did not take account of any users who have contractual arrangements that pass-through TNUoS costs (and therefore don't carry a risk premium). As there are no available data sources known to the Workgroup of the prevalence of pass-through arrangements in the non-domestic market, the Proposer included a range of scenarios to show how the benefit reduces as the proportion of customers with TNUoS pass-through increases e.g. if 50% of the non-domestic market has TNUoS pass-through the average annual benefit for non-domestic consumers benefit reduces to £16.3m.

Transmission Owner Analysis
The Transmission Owner representatives argued that the new Allowed Revenue true-ups[3] which would be required as a consequence of implementing CMP286/287 could be greater than any benefit from a reduced risk premia energy suppliers may make for end consumers overall. Their view is that CMP286/287 introduces tariff volatility and longer term uncertainty rather than resolving it.

Using the numbers provided in the Proposer's initial analysis, an Onshore Transmission Owner representative presented their view of the level of Allowed Revenue true-ups for 2021/22 and 2022/23.In their view, the Onshore Transmission Owner analysis (provided

[2] Note that a respondent to the Workgroup Consultation stated that data gathered through the Request for Information exercise does not provide full information as to what TNUoS-related risk premiums all industry participants charge, due to different parties' view of risk and their different ways of contracting

[3] Trued-up at their nominal Weighted Average Cost of capital (WACC), which represents a firm's average cost of capital from all sources. Assumes a true up at nominal cost of capital (6%) but have included a scenario with this at 8% included to provide a range especially noting that inflation is going up in the current market conditions

in Annex 10) showed that customers would have likely faced additional costs of ~£19m and £20m respectively when adjusting for the greater than £300m true up in each year that would have arisen when setting revenues +15 months ahead as opposed to the current arrangements. The nature of how Transmission Owner analysis revenues are set and recovered would always lead to these financial mismatches as a consequence of implementing CMP286/287, with additional increasing uncertainty when moving from one Price Control period to the next. The Onshore Transmission Owner representative were concerned that there was minimal ability for the ESO or Transmission Owners to accurately forecast these mismatches in future. The Onshore Transmission Owner also argued that the financial benefit anticipated by the Proposer of implementing CMP286/287 in future years will exceed these Transmission Owner cashflow deltas and any adverse impact would be felt in customer bills.

The Transmission Owner representative noted that the additional cost difference is due primarily to transitional issues due to Price Control uncertainty early in RIIO (Revenue = Incentives + Innovation + Outputs) T2 period. The ambiguity on Transmission Owner revenues caused by moving from one Price Control period to the next is a short-term issue. The increased use of uncertainty mechanisms[4] in the RIIO T2 Price Control by default also leads to greater uncertainty of Transmission Owner revenues as the Transmission Owner representatives argue that this presents an unforeseeable variable which may impact forecast accuracy in the longer term Transmission Owner representatives also noted that the additional cost to customers of these true-ups in the time period proposed under CMP286/287 is a known additional cost (once actual inflation and other inputs are known) and argue that the reduction in risk premia is not necessarily known.

Minimal changes to existing tariff setting processes

The ESO Workgroup Member confirmed that the CMP286 and CMP287 Original solution does not materially change the ESO tariff setting process (assuming they would receive the same level of inputs and granularity as they do now and any necessary changes are made to the STC and/or Transmission Licence) as the solution fixes inputs rather than tariffs and the inputs are not materially changing - they will be simply set earlier.

However, the ESO Workgroup Member noted that the post tariff setting process, to reconcile the larger difference between actual and recovered revenue, may be more complex as ESO would be collecting money over an additional year (3 years rather than 2) to fully recover the difference. This is illustrated in Diagram 5 below.

[44] Uncertainty Mechanisms exist to allow price control arrangements to respond to change. They protect both end consumers and licensees from unforecastable risk or changes in circumstances.

Diagram 5

Proposed solution, recovery of 2025/26 total costs							
		£m		Tariffs 2025/26	Tariffs 2026/27	Tariffs 2027/28	Tariffs 2027/28
				Jan-25	Jan-26	Jan-27	Jan-28
Forecast Costs	Dec-23	70		70			
	Dec-24	75	5		5		
	Dec-25	76	1			1	
Actual Costs*	Dec-26	77	1				1
Current process, recovery of 2025/26 total costs							
Forecast Costs	Dec-23	70					
	Dec-24	75		75			
	Dec-25	76	1		1		
Actual Costs*	Dec-26	77	1			1	

* Actual costs are known Mar-26

Currently, ESO would set a view of forecast revenue for 2025/26 in December 2024 and this would be recovered through 2025/26 tariffs. A refined view of the forecast would be made at December 2025 and the delta recovered through 2026/27 tariffs. A final view of the forecast would be made at December 2026 and the final delta recovered through 2027/28 tariffs. In summary, it currently takes two years to fully recover the required revenue.

Under CMP286/287, a view of forecast revenue for 2025/26 would be set a year earlier at December 2023 and recovered through 2025/26 tariffs. A refined view of the forecast would be made at December 2024 and the delta recovered through 2026/27 tariffs. Another view of the forecast would be made at December 2025 and recovered through 2027/28 tariffs. A final view of the forecast would be made at December 2026 and the final delta recovered through 2028/29 tariffs. In summary, with proposed solution it would take three years to fully recover the required revenue.

The ESO agreed that they would seek to recover any gap as early as possible, the expectation being the majority would be recovered within the first year. If the majority is recovered within the first year, it is unlikely that this timing delay could cause potential cashflow issues for the ESO as long as the forecast deltas remain small. For the avoidance of doubt, the actual process for recovery remains unchanged.

First Workgroup Consultation Summary

The first Workgroup Consultation for CMP286 & CMP287 was issued on 4 April 2019, and there were 4 non-confidential responses from industry. This Workgroup Consultation is included as Annex 3 and the 4 non-confidential responses are included as Annex 4.

In summary:

- 3 respondents supported the change and implementation approach. 1 respondent did not provide comment; and
- 1 respondent proposed an alternative option to provide 6-8 months' notice rather than 15 months' notice. However, the respondent who proposed this is not looking to take this forward at this current time.

Second Workgroup Consultation Summary

The Workgroup held their second Workgroup Consultation between 6 April 2022 and 9 May 2022 and received 7 responses, all of which were non-confidential. The full responses and a summary of the responses can be found in Annexes 7 and 8 respectively. In summary:

- The majority of respondents who replied to the Workgroup Consultation (4 out of 7) agreed that this change this will lead to reduced risk premia. However, some respondents (3 out of 7) to the Workgroup Consultation argued that the case for change has not been proved; specifically, how this leads to reduced costs for consumers. This is discussed further above in the "Reduced Risk Premia" section.
- Most respondents supported implementation of 1 April 2024, but 1 respondent queried this delay coming into effect on 1 April 2026 (i.e. start of RIIO-T-3). Some respondents added that the CMP286/287 is one piece of the jigsaw and STCP and Licence changes may also need to be finalised. Both these points are discussed further below in the "When will this change take place?" section.
- Some respondents noted there would be increased cashflow volatility in relation to revenue collected for Transmission Owners given the expected increased delta between actuals and forecasts – Some respondents noted that strengthening the Price Control process would in their opinion mitigate volatility. This is discussed further in the "Transmission Owner Analysis" section above and "Impacts on Transmission Owners" section below.
- Some concerns over process complexity (reconciliation process) and cashflow risks, The ESO Workgroup Member proposed an alternative to mitigate this, but the Transmission Owner respondents also noted that there are a number of items included in Allowed Revenue which are not within their control.

Workgroup Alternatives

Alternative Solution(s)	**How does this differ from the CMP286 Original?**
Request for Alternative 1 – this became WACM1	As per Original but **relevant costs borne by The Company as defined in the Transmission Licence"** are not locked down 15 months ahead of tariffs

The ESO Workgroup Member proposed an alternative to the CMP286 Original where "**relevant costs borne by The Company as defined in the Transmission Licence"** are not locked down 15 months ahead of tariffs.

Chapter 3: Transmission Revenue Restriction of Electricity Transmission Licence for National Grid Electricity System Operator Limited

DIS_t means the amount derived as a result of:
(a) the total amount charged to the licensee in Regulatory Year t by Scottish Hydro Electric Transmission Plc, SP Transmission Ltd and National Grid Electricity Transmission Plc in respect of Site-Specific Charges (as such charges are set out in schedule ten of the STC), minus
(b) the total income received by the licensee in respect of Site Specific Connection Charges calculated and applied in accordance with the Statement of the Connection Charging Methodology as set out in Section 14 of CUSC in Regulatory Year t from customers in the respective Transmission Areas of Scottish Hydro Electric Transmission Plc and SP Transmission Ltd and National Grid Electricity Transmission Plc;

LF_t means the net payments made by the licensee under paragraph 3 of Standard Condition A4 (Payments by the Licensee to the Authority);

ITC_t means the amount equal to invoices in respect of participation in the inter-transmission system operator compensation mechanism arising from the participation by Great Britain in the inter-transmission system operator compensation mechanism as provided for in Article 49 of the Electricity Regulation (EU) 2019/943;

$BD_t = BDA_t - RBD_t$

where:

BDA_t means the aggregate value of Bad Debt the licensee has incurred or expects to incur, inclusive of RIIO-1 Bad Debt and COVID-19 Bad Debt, with respect to Transmission Network Charges owed to the licensee by one or more Defaulting Connection and Use of System Code Party, less the interest income accrued at the default rate set out in the CUSC net of the STC late payment rate of interest with respect to the COVID-19 Scheme; and

RBD_t means the aggregate value of monies received with respect to Bad Debt, inclusive of RIIO-1 Bad Debt and COVID-19 Bad Debt, previously recovered by the licensee via the BDA_t term, where the licensee has received cash through either the Defaulting Connection and Use of System Code Party or through the administrator or liquidator of a Defaulting Connection and Use of System Code Party.

TS_t means the amount (for the avoidance of doubt, including any amounts that are treated as capital contribution) derived as a result of:
(a) the total amount charged to the licensee in Regulatory Year t by Scottish Hydro Electric Transmission Plc, SP Transmission Ltd, National Grid Electricity Transmission Plc and any Offshore Transmission Owner in respect of Transmission Owner Final Sums (as such charges are defined in schedule nine of the STC), minus
(b) an amount equal to the income received by the licensee in Regulatory Year t in respect of users who reduce Transmission Entry Capacity or Developer Capacity or who terminate relevant bilateral agreements for connection access rights to the National Electricity Transmission System in the respective Transmission Areas of each of Scottish Hydro Electric Transmission Plc, SP Transmission Ltd, National Grid Electricity Transmission Plc and any Offshore Transmission Owner;

$NICF_t$ is derived in accordance with Special Condition 3.3 (RIIO-1 Network Innovation Competition);

$SIFF_t$ is derived in accordance with Special Condition 3.4 (Strategic Innovation Fund);

Diagram 6 below shows total costs as published for 2022/23 final tariffs and highlights (in yellow) the 'relevant costs borne by The Company'.

Diagram 6

Term	NGESO TNUoS Other Pass-Through			
	Apr-21 Initial Forecast	Aug-21 Forecast	Nov-21 Draft	Jan-22 Final
Embedded Offshore Pass-Through (OFETt)	0.58	0.58	0.58	0.70
Network Innovation Competition Fund (NICFt)	30.89	30.89	0.00	9.68
Strategic Innovation Fund (SIFt)	0.00	0.00	18.04	18.04
The Adjustment Term (ADJt)	0.00	0.00	63.04	65.11
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	552.85	557.23	568.05	594.51
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.37	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	1,764.46	1,764.46	1,863.63	1,795.07
SPT revenue pass-through (TSPt)	348.71	371.85	350.45	357.86
SHETL revenue pass-through (TSHt)	632.65	632.61	652.85	673.24
ESO Bad debt (BDt)	3.30	3.30	7.20	3.60
ESO other pass-through items (LFt + ITCt etc)	32.56	32.56	42.53	38.90
ESO legacy adjustment (LARt)	0.00	41.13	37.55	37.55
Total	**3,366.00**	**3,434.62**	**3,604.29**	**3,594.25**

Diagram 7

Diagram 7 isolates these costs which are ~ £70m as a Central Case forecast for 2022/2023.

Term	NGESO TNUoS Other Pass-Through			
	Apr-21 Initial Forecast	Aug-21 Forecast	Nov-21 Draft	Jan-22 Final
Site Specific Charges Discrepancy (DISt)	0	0	0	0
Termination Sums (TSt)	0	0	0	0
Network Innovation Competition Fund (NICFt) *	31	31	0	10
Strategic Innovation Fund (SIFt)	0	0	18	18
ESO other pass-through items (LFt + ITCt etc)	33	33	43	39
ESO Bad debt (BDt)	3	3	7	4
Costs borne by The Company	67	67	68	70

The ESO Workgroup Member shared the central case of what these costs may be (~ £70m in 2022/2023 final TNUoS tariffs forecast) and presented 2 other scenarios to show a range of what these costs could be in 2022/2023 final TNUoS tariffs. This is illustrated below:

Scenario	Higher Cost Scenarios	Forecast costs (in 2022/2023 final TNUoS tariffs forecast)
Central Case		~ £70m
Scenario 1	~ £100m	
Scenario 2	~ £150m	

Forecast revenue requirements, particularly when set a year earlier than current process, are uncertain and have the potential to under/over recover compared to actual revenue required. Scenarios 1 and 2 focus on particular volatile instances where the forecast has been set to under-recover and considers the potential for under-recovery for each cost item. Through this Workgroup Alternative, the amount of the Maximum Revenue value relating to ‘costs borne by The Company’ will be finalised 2 months before the start of the Financial Year.

The ESO Workgroup Member clarified that these costs will be passed through in the year they are incurred and will not be added to the ESO’s Regulatory Asset Value (RAV) and therefore, ESO would not receive a return for the Weighted Average Cost of Capital (WACC).

The Workgroup noted that these costs represent a small percentage of the total TNUoS revenue to be recovered (2% of £3.6 billion) and as such will have a minimal reduction on the risk premia reductions that the Supplier argues. However, the ESO Workgroup Member argued that they are an asset light business and do not wish to take on this additional cash flow risk.

A respondent to the Workgroup Consultation identified a possible alternative to set the Non Half Hourly tariffs with more than 2 months' notice and then set the Half Hourly tariffs / TNUoS Demand residual later when inputs are firm. This could create a distortion between cost-reflectivity between Half Hourly and Non Half Hourly tariffs, affect the TNUoS Demand residual and add complexity and more work for the ESO. However, this could arguably address the Proposer's issue. The Workgroup considered this and agreed not to take it forward as it creates a distortion between Half Hourly and Non Half Hourly tariffs, increases Supplier risk and adds complexity.

Workgroup Alternative Vote

On 9 September 2022, the Workgroup voted as to whether or not the proposed Request for Alternative should become a Workgroup Alternative CUSC Modification (WACM). The majority of the Workgroup did not believe this request for an Alternative may better facilitate the CUSC Objectives than the CMP286/287 Original. However, the Chair saved this request for the Alternative as although excluding these costs may not make much difference to the overall benefit (reduction in risk premia), this small amount could be important to ESO's finance. This request for Alternative became WACM1.

Legal Text

The legal text for this change can be found in Annex 9.

What is the impact of this change?

Impacts on Suppliers

If the CMP286 and CMP287 Original change is approved, Supplier representatives have argued that the reduction in volatility will lead to a reduction in the value of the risk premia Suppliers may apply, which could therefore reduce costs to electricity consumers.

The Transmission Owner representatives challenged whether or not extending the notice period was the only option and asked if there was anything more Suppliers could have looked at outside changing CUSC or Licences. Suppliers could choose to offer pass-through, or partial pass-through, contracts to consumers for multi-year contracts, but that would be a commercial decision The Proposer argued that Suppliers are fundamentally impacted by the base Data and therefore believe only CUSC or Licence changes can mitigate this volatility.

Impacts on Generators

There is not expected to be any impact for Generators as, although the revenue and impacts would be fixed under the CMP286 and CMP287 Original Solution, the Generation and Demand split doesn't charge.

Impacts on Transmission Owners

Under the CMP286 and CMP287 Original Solution, the cashflow risk for under/over-recovery of revenues by ESO will switch from Suppliers to Transmission Owners. In the view of the Transmission Owner representatives, this is due to the new Allowed Revenue true-up/reconciliation to correct longer-term forecast versus actual mismatches, representing a new form of unpredictable volatility to the TNUoS tariff setting process for suppliers to mitigate. This is supported by their analysis discussed in the "Transmission Owner Analysis" section and Annex 10.

Transmission Owner representatives noted that Onshore Transmission Owners have a number of large investment projects (Large Offshore Transmission Investment in RIIO-T2) and while all revenue would continue to be recovered for these projects the revenues would no longer be aligned to investment in the way Transmission Owners expected. Transmission Owner representatives added that if revenues for these large projects were not adjusted close to when they are incurred, Transmission Owners could face a material cashflow shortfall compared to what they might otherwise have expected.

Transmission Owners argued that strengthening the RIIO Price Control process with Ofgem (namely more forecast certainty during business plan submissions and draft and final determinations) could help reduce uncertainty and revenue forecasting volatility for Transmission Owners. Transmission Owners have already engaged further with Ofgem to understand whether Ofgem can bring forward their timetable for producing the Price Control Financial Model (PCFM)[5] (which drives their actual data submission to ESO) and lock down the data a year earlier than now. Alternatively, the Transmission Owners will need to provide estimates, which will be less accurate given the increased notice period as compared to the baseline and seek to recover in the following year. For Ofgem to change their process, then the benefit of doing this needs to be understood at least from a qualitative perspective. The Proposer and some Workgroup Members are ambivalent as to which process is followed.

Transmission Owners confirmed that, in their view, the following technical changes will be necessary to their Electricity Transmission licence to support this solution.

- Special Condition (SC) 2.1 - wording referring to the Annual Iteration Process (e.g. definition of ADJR*t term)
- Special Condition 8 - reference the fact that the Annual Iteration Process of year T-2 will be used to direct revenues for year T-1.
- Price Control Financial Handbook - Chapter 2 to reference the fact that the Annual Iteration Process of year T-2 will be used to direct revenues for year T-1.
- Price Control Financial Model - 'AR' tab/macros to amend the functionality to set ADJR*t in Annual Iteration Process year T-2 rather than T-1.
- Consequential changes to the Price Control Financial Model guidance.

The Transmission Owners representatives also noted that to support CMP286/287 solutions, all parties allowed revenues will be set +15 months in advance, including a view of interconnectors/OFTOs (Offshore Transmission Owners). However, under the current Price Control arrangements, the Interconnectors/OFTOs receive updated revenues during the year (their 'live' allowed revenues) and the difference between the view set at tariff setting and the actual they received is borne by the onshore Transmission Owners (Ofgem noted in their **CMP244** decision that OFTO allowed revenues could vary by up to 15% if set 200 days in advance – this risk grows as OFTOs/Interconnector revenues are set to

[5] Annually updated by Ofgem and includes all the data, the Transmission Owners need to understand their price control costs and revenues. Transmission Owners receive a draft in August and then a final version in November

grow). Therefore, the onshore Transmission Owners are left with the interconnector/OFTO's volatility in allowed revenues, as well as collected revenues, and the variability in these revenues can increase significantly when forecasting 15 months ahead.

Impacts on ESO

ESO confirmed that the CMP286 and CMP287 Original solution do not change the ESO tariff setting process (assuming they would receive the same level of inputs and granularity as they do now and necessary associated changes to STC and licences are also implemented). The ESO Workgroup Member noted that the post tariff setting process (to calculate the Adjustment and K Factors to feed into the following year's TNUoS tariff setting process) will potentially be more complex as ESO would be collecting money over an additional year (3 years rather than 2) to fully recover the difference. However, the process itself will remain unchanged.

The ESO Workgroup Member proposed an alternative (this became WACM1) to the CMP286 Original where *"relevant costs borne by The Company as defined in the Transmission Licence"* are not locked down 15 months ahead of tariffs. The ESO Workgroup Member argued that they are an asset light business and do not wish to take on this additional cash flow risk. This is further discussed in the "Workgroup Alternatives" section of this document.

Impacts on Consumers

A typical domestic or business customer, whose meter is settled on non-half hourly data (NHH) and agrees a two-year fixed price contract with their Supplier will have TNUoS costs reflected within their contract rates. This will comprise a best view forecast plus an element of risk based on volatility and unpredictability of this charge for the period where final tariffs have not yet been published. Based on a NHH two-year contract starting in October, TNUoS tariffs are only known for a quarter of the contracted period, the remaining three-quarters being reliant on a forecast so Supplier representatives have argued that a reduction in volatility will lead to a reduction in the value of the risk premia Suppliers may apply (for the remaining three-quarters that is reliant on a forecast), which could therefore reduce costs to electricity consumers.

Supplier representatives on the Workgroup noted it would be in their best interests, as they operate in a competitive environment regulated by Ofgem, to pass on reduced risk premia to their customers.

The TO representatives highlighted the new volatility created by the CMP286/287 solutions which will, in their view, have a negative impact on end consumers in driving longer term uncertainty in tariffs and potential increase in costs due to cashflow risk and financing costs (as explained above).

Proposer’s assessment against Code Objectives

CMP286 and CMP287[6]

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;	Positive Final TNUoS tariffs are published with a notice period of only 2 months. Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require. This modification will give more certainty to inputs into the TNUoS Charging Methodology that market participants cannot forecast, thereby making the costs that customers pay more reflective of the final charge and consequently reduce the risk premia charged by suppliers. This will reduce the price distortions in the competitive market thereby facilitating effective competition in retail energy supply.
(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. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and	**Neutral**
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Neutral**
*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	

[6] Proposer’s assessment was the same for both CMP286 and CMP287

Authority Decision to send – back CMP286

Why was CMP286 a send-back?

On 30 June 2023, the Authority sent back CMP286 (Annex 16) in accordance with Section 8.23.12 and Section 8.23.13 and noted the following:

Deficiencies of Final Modification Report

On 10 October 2017 E.ON Energy raised two CUSC Modification Proposals CMP286 and 287. These modifications seek to increase the notice period of the Target Revenue component (CMP286) and the demand volume (CMP287) in the TNUoS tariff setting process from two months to fifteen months. Given the interactions between the proposed solutions, the modifications were progressed by a single Workgroup. Whilst it is allowed for the modifications to be considered together, they were never formally amalgamated under CUSC procedures meaning that they remain two distinct code modification proposals. In the FMR (Final Modification Report) submitted to the Authority, these two modifications have been treated as a single CUSC modification proposal and assessed accordingly. Further, there is only one set of combined Legal Text for both modifications annexed to the FMR.

Reasons for send back:

(a) Procedural issues: single set of Panel voting and a single proposed Legal Text.
(b) Lack of analysis of the impact of CMP287 alone.

The Authority's Expectations

The Authority directed that further analysis should be conducted on the impact of CMP287 and on the submitted FMRs should include separate voting and provision of Legal Text for each modification, or the modifications should be formally amalgamated. After addressing these issues, the CUSC Panel should re-submit the revised FMR(s) to the Authority for decision as soon as practicable.

What approach was agreed at CUSC Panel to address this?

The CUSC Panel on 28 July 2023 agreed next steps following the send-back on 30 June 2023.

- They noted that the two modifications had never been formally amalgamated by the Panel, so it should have been sent off as two separated FMRs and Legal Text.
- They noted that the Authority are asking the Final Modification Report, Legal Text and Voting to be revised and resubmitted.
- They agreed that this needs to be assessed by a Workgroup *(there is no Workgroup Consultation, or Workgroup Report and no further Workgroup Alternatives can be raised).*
- They agreed the to add two additional Terms of Reference to answer the deficiencies within the send back letter from the Authority; and
- They agreed (following the assessment by the Workgroup) that a Code Administrator Consultation is needed to be held before it is re-presented to Panel for Recommendation Vote.

Workgroup Discussions following Authority Send Back Decision

The Workgroup met on 20 September 2023, 06 October 2023 and 08 November 2023 to address these Terms of Reference and the discussions and conclusions are set out below:

- The Workgroup agreed to not amalgamate and keep both modifications (CMP286 and CMP287) separate,
- Review the DFMR (Draft Final Modification Report) and Legal Text, in order produce once of each for each modification.
- To vote on each modification separately.
- To make clear the analysis regarding CMP286.

Risk Premia data CMP286

CMP286	2018 Demand			
Scenario	Current Premia (£m)	CMP286 Premia (£)	Variance (£)	Variance (%)
Domestic A	22.9	17.9	-5.0	-22%
Domestic B	28.2	20.2	-8.0	-28%
Domestic C	27.8	24.1	-3.7	-13%
Non-dom 100% fixed	105.8	80.5	-25.3	-24%
Non-dom 75% fixed	79.4	60.4	-19.0	-24%
Non-dom 50% fixed	52.9	40.3	-12.7	-24%
Non-dom 25% fixed	26.5	20.1	-6.3	-24%

2022 Demand			
Current Premia (£m)	CMP286 Premia (£)	Variance (£)	Variance (%)
16.9	13.2	-3.7	-22%
20.7	14.9	-5.9	-28%
20.5	17.7	-2.7	-13%
96.1	73.1	-23.0	-24%
72.1	54.8	-17.2	-24%
48.0	36.5	-11.5	-24%
24.0	18.3	-5.7	-24%

The analysis for CMP286 demonstrates how historic variance in TNUoS revenue forecasts published by the ESO impact suppliers risk premia. This excludes any impacts of demand charging base variations which relates to CMP287 only.

WACM1

The Workgroup advised and agreed that the WACM1 relates to CMP286 only (Annex 2).

Send Back Terms of Reference

For CMP286 the Workgroup only considered the additional Term of Reference g). They agreed that the additional Term of Reference h) was only applicable for CMP287 and should be addressed separately within that modification discussion (Annex 17).

CMP286 Legal Text

The Workgroup reviewed and separated the Legal Text for CMP286 from the previous submitted Legal Text that included CMP287.

Legal text for CMP286 can be found in Annex 18.

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;	Positive Final TNUoS tariffs are published with a notice period of only 2 months. Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require. This modification will give more certainty to inputs into the TNUoS Charging Methodology that market participants cannot forecast, thereby making the costs that customers pay more reflective of the final charge and consequently reduce the risk premia charged by suppliers. This will reduce the price distortions in the competitive market thereby facilitating effective competition in retail energy supply.
(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. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1; and	Neutral
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	Neutral
*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 following Authority Send Back Decision

The Workgroup met on the 6 November 2023 to carry out their Workgroup Vote, after the voting there were some comments made to the Legal Text that needed further consideration from the Workgroup.

The Workgroup met again on 8 November 2023 to agree to the Legal Text changes and reconfirm their Workgroup Vote for CMP286. The full Workgroup vote can be found in Annex 19. The tables below provide:

- a summary of how many Workgroup members believed the Original and WACM1 for CMP286 were better than the Baseline (the current CUSC); and
- a summary of the Workgroup Members views on the best option to implement CMP286.

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

Assessment of the Original and WACM1 vs Baseline

The Workgroup concluded by majority that the Original better facilitated the applicable CUSC Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	5
WACM1	0

Best Option

Workgroup Member	Company	Best Option	Which objective(s) does the change better facilitate?
Niall Coyle	E.ON	Original	a)
Stephen Dale	National Grid ESO	Baseline	Not applicable
Andy Colley	SSE Generation Ltd.	Original	a)
Karl Maryon	Drax	Original	a)
Simon Vicary	EDF Energy	Original	a) and e)
Richard Woodward	NGET	Baseline	Not applicable
Robert Longden	Cornwall Energy	Original	a)

Second Code Administrator Consultation Summary:

The Second Code Administrator Consultation was issued on the 29 November 2023 closed on 05 January 2024 and received 7 non – confidential responses. A summary of the responses can be found below, and the full responses can be found in Annex 20.

- Five out of seven respondents agree that the Original Solution and WACM1 better facilitate the Applicable CUSC Charging Objectives.
- Majority of respondents support the Original Solution, noting it is simpler to implement.
- One respondent noted that the original Solution places additional risk on the ESO cash flow, therefore supportive of WACM1.
- Majority of respondents support the proposed implementation approach.
- One respondent noted that they would be supportive of an earlier implementation date.
- One respondent doesn't support the proposed implementation approach and recommends CMP286 should be implemented for the second year of the T3 Price Control.
- A respondent noted that CMP286 introduces additional material risks for the Onshore TOs' Price Control arrangements.
- Two respondents believe further work is required, which could be addressed under CMP413 'Rolling 10-year wider TNUoS generation tariffs, TNUoS Task Force and the Strategic Transmission Charging reform programme.

Second Panel Recommendation Vote:

The Panel will meet on the 26 January 2024 to carry out their recommendation vote. They will assess whether a change should be made to the CUSC by assessing the proposed change and any alternatives against the Applicable Objectives.

Vote 1: Does the Original or WACM1 facilitate the objectives better than the Baseline?

Panel Member: **Andrew Enzor**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Andy Pace**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Binoy Dharsi**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Claire Huxley**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Garth Graham**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Joe Colebrook**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Joseph Dunn**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Kyran Hanks**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Panel Member: **Paul Jones**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

Vote 2 – Which option is the best?

Panel Member	Best Option	Which objectives does this option better facilitate?
Andrew Enzor		
Andy Pace		
Binoy Dharsi		
Claire Huxley		
Joe Colebrook		
Joseph Dunn		
Kyran Hanks		
Paul Jones		

Panel conclusion

Panel will meet on 26 January 2024 to carry out their recommendation vote.

When will this change take place?

Implementation date

31 December 2024 (Effective from 1 April 2026 – 15 months after Implementation Date)
The Transmission Owner representatives propose implementation to take effect for revenue setting for the first year of the T3 Price Control (i.e. Q3 2026). However, the Ofgem representative on the Workgroup confirmed that the Effective Date would not necessarily need to coincide with the start of the T3 Price Control.

Date decision required by

30 September 2024
STCP changes and changes to the Transmission Owner licence also need to be in place by this date.

Implementation approach

If the CMP286 solution is approved, STCP changes would be needed but are expected to be in place ahead of any implementation.

The Proposer originally sought a decision by 31 October 2022 to allow implementation on 31 December 2022 and an Effective Date of 1 April 2024. However, changes to the Transmission Owner licence could not be completed by 31 October 2022 as the licence change process would take 6 months and would include the following:

- Stakeholder consultation (4-12 weeks) depending on materiality.
- Statutory consultation (28 calendar days); and
- Effective 56 calendar days after Ofgem decision.

It would not be appropriate for Transmission Owners to calculate allowed revenues (based on a 15 month notice period) with changes to the Transmission Owner licence not in place.

The Authority send back of CMP286 impacted the implementation expectations described above, moving implementation to 1 April 2026.

Interactions

☐Grid Code	☐BSC	☒STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[7]	☐Other modifications	☐Other

Acronyms, key terms and reference material

Acronym / key term	Meaning
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DNO	Distribution Network Operators
DUoS	Distribution Use of System

[7] 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.

EBR	Electricity Balancing Guideline
ESO	Electricity System Operator
HH	Half Hourly
Mwh	Megawatt per hour
NHH	Non - Half Hourly
RAV	Regulatory Asset Value
RIIO	Revenue = Incentives + Innovation + Outputs
STC	System Operator Transmission Owner Code
STCP	System Operator Transmission Owner Code Procedure
SQSS	Security and Quality of Supply Standards
T&Cs	Terms and Conditions
TNUoS	Transmission Network Use of System
WACC	Weighted Average Cost of Capital
WACM	Workgroup Alternative CUSC Modification

Reference material

- None

Annexes

Annex	Information
Annex 1	CMP286 and CMP287 Proposal form
Annex 2	CMP286 and CMP287 Terms of Reference
Annex 3	CMP287 1st Workgroup Consultation
Annex 4	CMP287 1st Workgroup Consultation Responses
Annex 5	Request for Information 31 May 2018 – results of analysis
Annex 6	Proposer's Analysis to demonstrate TNUoS volatility
Annex 7	2nd Workgroup Consultation Responses summary
Annex 8	2nd Workgroup Consultation Responses
Annex 9	Pre-Send back CMP286 and CMP287 Legal Text
Annex 10	Transmission Owner Analysis
Annex 11	CMP286 WACM1
Annex 12	First Workgroup Vote
Annex 13	First CMP286 & CMP287 Code Administrator Consultation Summary
Annex 14	First CMP286 & CMP287 Code Administrator Consultation Responses
Annex 15	First Panel Recommendation Vote
Annex 16	CMP286 & CMP287 Authority Send Back letter
Annex 17	Post Send Back CMP286 Terms of Reference
Annex 18	Post Send Back CMP286 Legal Text
Annex 19	Post Send Back CMP286 Workgroup Vote
Annex 20	CMP286 Second Code Administrator Consultation Responses and Summary