Version 1.0

November 2024

Draft Forecast of TNUoS Tariffs for 2025/26

National Energy System Operator

NESO
National Energy System Operator

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Executive Summary

Executive Summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Draft forecast of TNUoS Tariffs for 2025/26.

Under the National Energy System Operator's (NESO) Electricity System Operator Licence condition E10 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2025/26 on our website[1].

This forecast is for charging year 2025/26 and has no impact on 2024/25.

Total revenues to be recovered

The total TNUoS revenue is forecast at £5.5bn for 2025/26, (an increase of £234.85m from the July forecast). This increase is mainly due to revisions to Onshore Transmission Owner (ONTO) Allowed Revenue that was submitted in October 2024. These are the first full submissions since January 2024, resulting in changes for NGET (+£92.48m), SPT (+£27.6m) and SHET (+£128.06m). There have also been changes to other pass-through items offset by revisions to Offshore Transmission Owner (OFTO) revenue inflation and forecast OFTO Asset Transfer Dates.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.16bn for 2025/26, a decrease of £15.1m since the July forecast. This is mainly driven by the decrease in revenue from offshore local tariffs.

The generation charging base has been updated to 94.8GW based on our best view on generation projects for 2025/26. This is a decrease of 4.5GW since the July forecast. The average generation tariff is £12.27/kW, an increase of £0.40/kW due to the decrease in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £4.34bn for 2025/26, a £250m increase since the July tariffs. The increase in demand revenue is the result of the increase in TNUoS revenue and the proportion of demand % increasing since July forecast (77.6% compared to 78.9% now).

The bill for the average domestic consumer is forecast to be £56.28 for FY25/26 (6.4% of the average annual electricity consumer bill), an increase of £4.35 from the 2025/26 July forecast. This is due to the increase in allowed revenue since the July forecast.

In 2025/26, it is forecast that £24.27m would be payable to embedded generators (<100MW) through the

[1] neso.energy/industry-information/charging/tnuos-charges

Embedded Export Tariff (EET), an increase of £4m since the July forecast. This is due to the increase in the average locational tariffs. The average EET is forecast at £3.11/kW, which is an increase of £0.40/kW versus the July forecast.

The average gross HH demand tariff for 2025/26 is forecast to be £7.81/kW, an increase of £1.17/kW compared to July forecast and the average NHH demand tariff forecast is forecast to be 0.38p/kWh, an increase of 0.07p/kWh since the July forecast.

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2025/26 is available on our website[2].

Our next TNUoS tariff publication will be the Final 2025/26 TNUoS tariffs, which will be published in January 2025.

Feedback

We welcome feedback on any aspect of this document and the tariff setting processes.

We are very aware that TNUoS charging is undergoing transition and there will be substantial changes to charging mechanisms over the next few years, either as a result of Ofgem's charging review or through CUSC modifications raised from time to time.

We strongly encourage all parties affected by the changes to the charging regime to engage with the Charging Futures Forum, or with the specific CUSC modification workgroups to flag any concerns and suggestions.

Please contact us if you have any further suggestions as to how we can better work with you to improve the tariff forecasting process.

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[2] neso.energy/document/301571/download

Charging Methodology Changes

This Report

This report contains the Draft forecast of TNUoS tariffs for the charging year 2025/26.

This report is published without prejudice. Whilst every effort has been made to ensure the accuracy of the information, it is subject to several estimations, assumptions and forecasts and may not bear relation to the final tariffs we will publish at a later date.

This section summarises any key changes to the methodology.

Charging Methodology Changes

CMP424: 'Amendments to Scaling Factors used for Year Round TNUoS Charges' has been approved by Ofgem for implementation on 1 April 2025.

This modification introduces a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of the Year Round background tariff calculation within the Transport model. The changes introduced by CMP424 have been incorporated into this forecast.

CMP430: 'Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme' has been approved by Ofgem for implementation on 1 April 2025.

This modification aims to rectify defects relating to demand locational Transmission Network Use of System (TNUoS) charging that would otherwise have become apparent during the Migration Phase of the Market Wide Half Hourly Settlement (MHHS) Programme. CMP430 does not impact on the calculation of the tariffs themselves and therefore has no impact on this forecast.

There are also a number of 'in-flight' proposals to change the charging methodologies, which may impact TNUoS tariffs and charges. These are summarised in the CUSC modifications Table 24.

TNUoS Task Force and electricity network charging

In May 2022, Ofgem published an open letter[3] outlining their thinking on the scope of the work to be undertaken by a Task Force and asked NESO to work with industry to establish membership. In the letter, Ofgem clarified that the Task Forces will look at improvements to today's methodology whilst keeping its core assumptions and modelling approach unchanged. They stated that this does not rule out significant changes to elements of TNUoS, for example, the transport model, changes to the 'backgrounds' against which

[3] ofgem.gov.uk/publications/tnuos-task-forces

charges are calculated, or the approach to the demand-weighted distributed reference node.

Task Force Workstream analysis and defect identification has resulted in a number of proposed CUSC changes which continue to go through the usual CUSC modification process. Further detail regarding the priority areas and Task Force meeting materials can be located on the NESO website[4].

[4] neso.energy/industry-information/charging/charging-futures/task-forces

Generation Tariffs

Generation Wider Tariffs

Onshore Local Substation Tariffs

Onshore Local Circuit Tariffs

Offshore Local Tariffs

Generation Tariffs Summary

This section summarises our view of generation tariffs for 2025/26 and how these tariffs were calculated.

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	2025/26 July	2025/26 November	Change since last forecast
Adjustment	- 1.720165	- 1.558845	0.161320
Average Generation Tariff*	11.871725	12.272536	0.400812

*N.B. These generation average tariffs include local tariffs.

The average generation tariff is calculated by dividing the total revenue payable by generation over the generation charging base in GW. These average tariffs include revenues from local tariffs.

The generation adjustment is used to ensure generation tariffs are compliant with the Limiting Regulation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. The adjustment tariff is currently negative to ensure Generation Tariffs are compliant with the legislation. Charges for the "Connection Exclusion" (meaning assets built for generation connection) are not included in the €2.50/MWh cap, whereas TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Average generation tariffs have increased by £0.40/kW, due to the 4.5GW decrease in the generation charging base, compared to the July forecast. The generation adjustment has increased by £0.16/kW, decreasing in magnitude, to become less negative; this is because the revenue to be collected from generator tariffs is expected to decrease, which outweighs the decrease in the charging base since the July forecast and therefore less of an adjustment is required to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

Generation Wider Tariffs

The following section summarises the wider generation tariffs for 2025/26. A brief description of generation wider tariff structure can be found in Appendix A.

The wider tariffs are calculated depending on the generator type and made of four components:

- the Peak tariff (not applicable to intermittent generators);
- the Year Round Shared tariff (applicable to all generators and multiplied by the generator's specific Annual Load Factor (ALF));
- the Year Round Not Shared tariff (applicable to all generators, multiplied by the generator's specific Annual Load Factor (ALF) for Conventional Carbon generators only);

- the Adjustment tariff (applicable to all generators).

Annual Load Factors are explained in Appendix D.

The classifications of generator type are listed below:

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass	Nuclear	Offshore wind
CCGT/CHP	Hydro	Onshore wind
Coal		Solar PV
OCGT/Oil		Tidal
Pumped storage		
Battery storage		
Reactive Compensation		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF. The example ALFs we have used in this forecast are:

- **Conventional Carbon – 40%**
- **Conventional Low Carbon – 75%**
- **Intermittent – 45%**

The ALFs used in these examples are for illustration only. Tariffs for individual generators are calculated using their own ALFs where we have 3 or more years of data, or their own data combined with the generic ALFs if we don't.

Table 2 Generation Wider Tariffs

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Example tariffs for a generator of each technology type: Conventional Carbon 40%	Conventional Low Carbon 75%	Intermittent 45%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	1.566830	23.112512	17.522464	-1.558845	16.261975	34.864833	26.364249
2	East Aberdeenshire	2.474842	14.759349	17.522464	-1.558845	13.828722	29.507973	22.605326
3	Western Highlands	1.610440	21.585154	16.372128	-1.558845	15.234508	32.612589	24.526602
4	Skye and Lochalsh	1.540257	21.585154	23.664713	-1.558845	18.081359	39.834991	31.819187
5	Eastern Grampian and Tayside	1.357724	17.760593	12.905898	-1.558845	12.065475	26.025222	19.339320
6	Central Grampian	3.640355	17.615595	12.767285	-1.558845	14.234662	28.060491	19.135458
7	Argyll	3.777476	15.917911	23.258086	-1.558845	17.889030	37.415150	28.862301
8	The Trossachs	2.172581	15.917911	11.120158	-1.558845	11.428964	23.672327	16.724373
9	Stirlingshire and Fife	1.125561	15.541061	10.882471	-1.558845	10.136129	22.104983	16.317103
10	South West Scotlands	1.810032	14.894551	10.580649	-1.558845	10.441267	22.002749	15.724352
11	Lothian and Borders	0.982082	14.894551	4.852855	-1.558845	7.322199	15.447005	9.996558
12	Solway and Cheviot	0.421702	10.473697	6.900150	-1.558845	5.812396	13.618280	10.054469
13	North East England	1.761405	7.106854	3.840890	-1.558845	4.581658	9.373591	5.480129
14	North Lancashire and The Lakes	0.414380	7.106854	0.916939	-1.558845	2.065052	5.102615	2.556178
15	South Lancashire, Yorkshire and Humber	2.413833	3.394326	0.630636	-1.558845	2.464973	4.031369	0.599238
16	North Midlands and North Wales	1.982134	1.302840	0.005845	-1.558845	0.946763	1.406264	-0.966722
17	South Lincolnshire and North Norfolk	1.022044	2.774886	0.006283	-1.558845	0.575667	1.550647	-0.303863
18	Mid Wales and The Midlands	0.486804	2.530650	0.006283	-1.558845	-0.057268	0.832230	-0.413770
19	Anglesey and Snowdon	6.064157	0.575392	0.005845	-1.558845	4.737807	4.942701	-1.294074
20	Pembrokeshire	9.884578	-8.208996	-	-1.558845	5.042135	2.168986	-5.252893
21	South Wales & Gloucester	4.672336	-9.427678	-	-1.558845	-0.657580	-3.957268	-5.801300
22	Cotswold	4.015365	1.629818	-9.676204	-1.558845	-0.762034	-5.997321	-10.501631
23	Central London	-2.871424	1.629818	-5.887674	-1.558845	-6.133411	-9.095580	-6.713101
24	Essex and Kent	-1.742934	1.629818	-	-1.558845	-2.649852	-2.079416	-0.825427
25	Oxfordshire, Surrey and Sussex	-0.312513	-5.004122	-	-1.558845	-3.873007	-5.624450	-3.810700
26	Somerset and Wessex	-0.862956	-7.075496	-	-1.558845	-5.251999	-7.728423	-4.742818
27	West Devon and Cornwall	0.662422	-12.500648	-	-1.558845	-5.896682	-10.271909	-7.184137

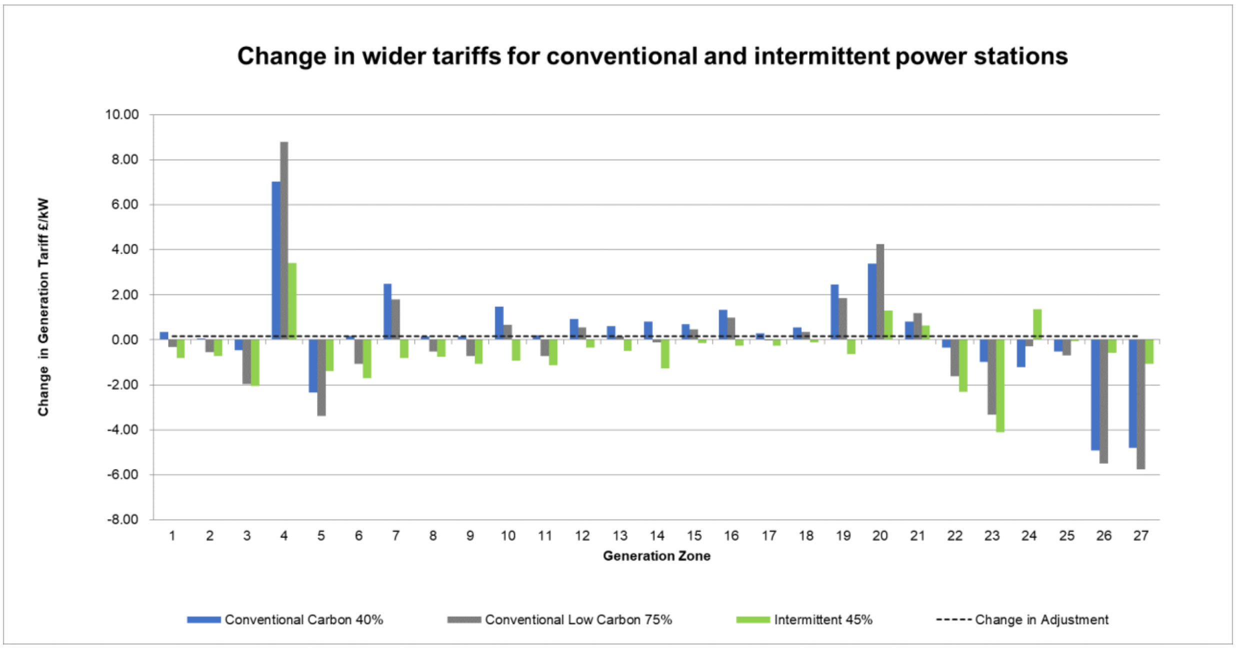
Changes to Wider Tariffs since the July Forecast

The following section provides details of the wider generation tariffs for 2025/26 and explains how these have changed since the July forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only.

Table 3 Generation Wider Tariff Changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			Change in Adjustment
		2025/26 July	2025/26 November	Change	2025/26 July	2025/26 November	Change	2025/26 July	2025/26 November	Change	
1	North Scotland	15.926214	16.261975	0.335762	35.195250	34.864833	-0.330416	27.168323	26.364249	-0.804073	0.161320
2	East Aberdeenshire	13.774536	13.828722	0.054186	30.051385	29.507973	-0.543412	23.321225	22.605326	-0.715899	0.161320
3	Western Highlands	15.698281	15.234508	-0.463773	34.579053	32.612589	-1.966465	26.588504	24.526602	-2.061901	0.161320
4	Skye and Lochalsh	11.061144	18.081359	7.020215	31.036580	39.834991	8.798410	28.412945	31.819187	3.406243	0.161320
5	Eastern Grampian and Tayside	14.416630	12.065475	-2.351155	29.421017	26.025222	-3.395795	20.727974	19.339320	-1.388654	0.161320
6	Central Grampian	14.057680	14.234662	0.176982	29.146086	28.060491	-1.085595	20.858213	19.135458	-1.722755	0.161320
7	Argyll	15.405057	17.889030	2.483972	35.625705	37.415150	1.789446	29.663375	28.862301	-0.801074	0.161320
8	The Trossachs	11.285302	11.428964	0.143661	24.196001	23.672327	-0.523673	17.480127	16.724373	-0.755754	0.161320
9	Stirlingshire and Fife	9.983186	10.136129	0.152943	22.824906	22.104983	-0.719923	17.376131	16.317103	-1.059027	0.161320
10	South West Scotlands	8.973289	10.441267	1.467978	21.329131	22.002749	0.673618	16.658116	15.724352	-0.933764	0.161320
11	Lothian and Borders	7.134380	7.322199	0.187819	16.168484	15.447005	-0.721479	11.121886	9.996558	-1.125328	0.161320
12	Solway and Cheviot	4.887321	5.812396	0.925074	13.072707	13.618280	0.545573	10.394014	10.054469	-0.339546	0.161320
13	North East England	3.982201	4.581658	0.599456	9.227372	9.373591	0.146218	5.963694	5.480129	-0.483564	0.161320
14	North Lancashire and The Lakes	1.261117	2.065052	0.803936	5.220270	5.102615	-0.117656	3.820332	2.556178	-1.264153	0.161320
15	South Lancashire, Yorkshire and Humber	1.774308	2.464973	0.690665	3.578074	4.031369	0.453295	0.736390	0.599238	-0.137152	0.161320
16	North Midlands and North Wales	-0.377427	0.946763	1.324190	0.411378	1.406264	0.994887	-0.689976	-0.966722	-0.276746	0.161320
17	South Lincolnshire and North Norfolk	0.291183	0.575667	0.284484	1.585243	1.550647	-0.034597	-0.040361	-0.303863	-0.263502	0.161320
18	Mid Wales and The Midlands	-0.591794	-0.057268	0.534526	0.500954	0.832230	0.331276	-0.299191	-0.413770	-0.114578	0.161320
19	Anglesey and Snowdon	2.268867	4.737807	2.468939	3.087200	4.942701	1.855501	-0.652011	-1.294074	-0.642062	0.161320
20	Pembrokeshire	1.667095	5.042135	3.375039	-2.081637	2.168986	4.250623	-6.539964	-5.252893	1.287071	0.161320
21	South Wales & Gloucester	-1.461974	-0.657580	0.804394	-5.129890	-3.957268	1.172622	-6.436056	-5.801300	0.634756	0.161320
22	Cotswold	-0.408030	-0.762034	-0.354005	-4.375860	-5.997321	-1.621460	-8.194126	-10.501631	-2.307505	0.161320
23	Central London	-5.159325	-6.133411	-0.974087	-5.768799	-9.095580	-3.326780	-2.596866	-6.713101	-4.116235	0.161320
24	Essex and Kent	-1.430942	-2.649852	-1.218910	-1.796054	-2.079416	-0.283361	-2.189596	-0.825427	1.364169	0.161320
25	Oxfordshire, Surrey and Sussex	-3.343457	-3.873007	-0.529550	-4.927191	-5.624450	-0.697258	-3.756395	-3.810700	-0.054305	0.161320
26	Somerset and Wessex	-0.345974	-5.251999	-4.906025	-2.237102	-7.728423	-5.491321	-4.151615	-4.742818	-0.591203	0.161320
27	West Devon and Cornwall	-1.096061	-5.896682	-4.800622	-4.520798	-10.271909	-5.751111	-6.123399	-7.184137	-1.060738	0.161320

Figure 1 Variation in generation wider zonal tariffs



Locational Changes

Locational tariffs have been impacted by the update of various locational inputs, including the nodal generation and demand and the network model used to model flows. This means that there have been changes in the overall tariffs across each generation zone. In particular, the change in flows has resulted in a large increase in zone 4, which is often sensitive to generation/demand changes, due to the relatively long radial circuits.

Also, delays to a number of projects (including most notably Hinkley Point C) have caused a significant reduction in Conventional Tariffs in zones 26 and 27.

It is worth noting that the final set of Nodal demand data was not available in time to be included within this publication and so will be further refined ahead of the Final Tariff publication in January. This means that Locational tariffs will be finalised in January.

Adjustment Tariff Changes

The adjustment tariff is currently forecast to be negative due to the wider tariffs causing the average generation charge to breach the cap.

The adjustment tariff has increased by £0.16/kW since the July forecast, decreasing in magnitude, to become less negative. This is because the revenue to be collected from generator tariffs is expected to decrease, which outweighs the decrease in the charging base since the July forecast and therefore less of an adjustment is required to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see

Table 23.

Onshore Local Substation Tariffs

Onshore local substation tariffs reflect the cost of the first transmission substation that each transmission connected generator connects to. They are recalculated in preparation for the start of each price control, based on TO asset costs and then inflated each year by the average May to October CPIH, for the rest of the price control period.

The CPIH figure used in the calculation of local substation tariffs has been finalised, and therefore onshore local substation tariffs are finalised for charging year 2025/26.

Table 4 Onshore Local Substation Tariffs

2025/26 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.179523	0.089766	0.061916
<1320 MW	Redundancy	0.378275	0.192132	0.136425
≥1320 MW	No redundancy	-	0.263729	0.187768
≥1320 MW	Redundancy	-	0.396867	0.285445

Onshore Local Circuit Tariffs

Where a transmission-connected generator is not directly connected to the Main Interconnected Transmission System (MITS), the onshore local circuit tariffs reflect the cost and flows on circuits between its connection and the MITS. Local circuit tariffs can change as a result of system power flows and inflation.

In this forecast, the 2025/26 onshore local circuit tariffs have been updated, and will be finalised by January 2025. The updated tariffs are listed below in Table 5. The tariffs for Arecleoch Extension and Strathy Wood have been removed as they no longer have contracted TEC within 2025/26.

Table 5 Onshore Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.711931	Douglas North	0.760858	Langage	-0.400734
Aberdeen Bay	3.347776	Dunhill	1.791917	Limekilns	2.411223
Achruach	-1.635918	Dunlaw Extension	0.528806	Lochay	0.380429
Aigas	0.879048	Dunmaglass	1.087393	Luichart	0.705603
An Suidhe	-1.051223	Edinbane	8.562243	Marchwood	-0.295126
Arecleoch	3.005452	Enoch Hill	0.760858	Mark Hill	1.103307
Ayrshire Grid Collector	0.169065	Ewe Hill	1.741520	Middle Muir	2.640178
Beinneun Wind Farm	1.687371	Fallago	-0.080082	Middleton	0.176522
Benbrack	0.910916	Farr	4.349028	Millennium Wind	1.994254
Bhlaraidh Wind Farm	0.761915	Faw Side	10.149596	Mossford	1.985636
Black Hill	1.919911	Fernoch	5.359768	Nant	-1.554983
Black Law	2.092360	Ffestiniogg	0.271855	Necton	0.955914
BlackCraig Wind Farm	6.924933	Fife Grid Services	0.189806	Rhigos	0.132023
BlackLaw Extension	4.551430	Finlarig	0.380429	Rocksavage	0.018420
Broken Cross	1.330261	Foyers	0.349528	Saltend	-0.019370
Clyde (North)	0.132397	Galawhistle	1.306140	Sandy Knowe	5.260736
Clyde (South)	0.154463	Glen Kyllachy	1.247184	Sanquhar II	8.652036
Coalburn BESS	0.469624	Glendoe	2.494369	Scoop Hill	0.539490
Corriegarth	3.043433	Glenglass	5.725310	Shepherds Rig	0.092199
Corriemoillie	1.985636	Gordonbush	0.010702	South Humber Bank	-0.221793
Coryton	0.050193	Griffin Wind	2.469555	Spalding	0.332851
Creag Riabhach	4.184720	Hadyard Hill	3.423862	St Fergus Mobil	1.275310
Cruachan	2.214906	Harestanes	2.853218	Stranoch	3.761346
Culligran	2.162159	Hartlepool	0.646198	Strathbrora	-0.117037
Cumberhead Collector	0.870760	Invergarry	0.380429	Strathy Wind	2.115402
Cumberhead West	4.614582	Kergord	61.164365	Stronelairg	1.340364
Deanie	3.552118	Kilgallioch	1.323968	Wester Dod	0.435380
Dersalloch	2.804200	Kilmarnock BESS	0.488409	Whitelee	0.132397
Dinorwig	3.127755	Kilmorack	0.154440	Whitelee Extension	0.375124
Dorenell	3.001461	Kype Muir	1.850365		

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way they are modelled in the Transport and Tariff model. This table shows the circuits which have been amended in the model, to account for the one-off charges that have already been applied to generators. For more information, please see CUSC sections 2, paragraph 14.4 and 14.15.15.

Table 6 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Bhlaraidh 132kV	Glenmoriston 132kV	7.4km Cable	7.4km OHL	Bhlaraidh
Enoch Hill 132kV	New Cumnock 132kV	4.4km Cable	4.4km OHL	Enoch Hill
Glen Glass 132kV	Sandy Knowe132kV	4km Cable	4km OHL	Sandy Knowe
Coalburn 132kV	Cumberhead Collector 132kV	8.01km Cable	8.01km OHL	Dalquhandy
Cumberhead Collector 132kV	Galawhistle 132kV	3.69km Cable	3.69km OHL	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km Cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km Cable	13km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.9km Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Melgarve 132kV	Stronelairg 132kV	10km Cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km Cable	15.33km OHL	Harestanes
Arecleoch 132kV	Arecleoch Tee 132kV	2.5km Cable	2.5km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	11.46km Cable	11.46km of OHL	Blacklaw
Earba PSH 400kV	Dalwhinnie 400kV	15km Cable	15km OHL	Earba PSH
Loch Nan Eun 275kV	Fort Augustus 400kV	6km Cable	6km of OHL	Loch Nan Eun
Red John 275kV	Knocknagael 275kV	9km Cable	9km OHL	Red John
Sheirdrim 132kV	Crossaig 132kV	3km Cable	3km OHL	Sheirdrim

Offshore Local Generation Tariffs

The offshore local tariffs (Substation, Circuit and Embedded Transmission Use of System) reflect the cost of the offshore networks which connect offshore generation to the mainland. They are calculated at the beginning of a price control or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed each year, in line with the revenue of the associated Offshore Transmission Owner. Since July, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs associated with projects due to transfer in 2024/25 or 2025/26 will be confirmed once asset transfer has taken place and tariffs have been set.

Table 7 Offshore local tariffs 2025/26

Offshore Generator	2025/26 July Tariff Component (£/kW)			2025/26 November Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.652416	61.559113	1.528597	11.649990	61.546296	1.528279	-0.002426	-0.012817	-0.000318
Beatrice	9.408052	25.795281	-	9.389647	25.744817	-	-0.018405	-0.050464	-
Burbo Bank Extension	14.612844	28.242150	-	14.584257	28.186900	-	-0.028587	-0.055250	-
Dudgeon	21.373594	33.535496	-	21.331780	33.469891	-	-0.041814	-0.065605	-
East Anglia 1	12.652206	53.395666	-	12.627454	53.291208	-	-0.024752	-0.104458	-
Galloper	21.878763	34.603514	-	21.835962	34.535819	-	-0.042801	-0.067695	-
Greater Gabbard	21.710871	50.241140	-	21.706351	50.230679	-	-0.004520	-0.010461	-
Gunfleet	25.358134	23.384749	4.370744	25.352854	23.379880	4.369834	-0.005280	-0.004869	-0.000910
Gwynt y mor	27.441143	27.130566	-	27.387460	27.077491	-	-0.053683	-0.053075	-
Hornsea 1A	9.767039	34.557311	-	9.747932	34.489707	-	-0.019107	-0.067604	-
Hornsea 1B	9.767039	34.557311	-	9.747932	34.489707	-	-0.019107	-0.067604	-
Hornsea 1C	9.767039	34.557311	-	9.747932	34.489707	-	-0.019107	-0.067604	-
Hornsea 2A	11.083084	37.440316	-	11.047354	37.319614	-	-0.035730	-0.120702	-
Hornsea 2B	11.083084	37.440316	-	11.047354	37.319614	-	-0.035730	-0.120702	-
Hornsea 2C	11.083084	37.440316	-	11.047354	37.319614	-	-0.035730	-0.120702	-
Humber Gateway	16.149266	37.051971	-	16.117673	36.979486	-	-0.031593	-0.072485	-
Lincs	22.419038	88.166410	-	22.375180	87.993930	-	-0.043858	-0.172480	-
London Array	15.214038	52.163106	-	15.184275	52.061059	-	-0.029763	-0.102047	-
Moray East	11.340976	28.407624	-	11.318789	28.352051	-	-0.022187	-0.055573	-
Ormonde	35.826120	66.966785	0.533669	35.818661	66.952842	0.533558	-0.007459	-0.013943	-0.000111
Race Bank	12.943260	35.949379	-	12.917939	35.879051	-	-0.025321	-0.070328	-
Rampion	10.573397	27.659557	-	10.552712	27.605447	-	-0.020685	-0.054110	-
Robin Rigg	-0.7863380	44.634171	14.300505	-0.7861740	44.624878	14.297527	0.00016	-0.009293	-0.002978
Robin Rigg West	-0.7863380	44.634171	14.300505	-0.7861740	44.624878	14.297527	0.000164	-0.009293	-0.002978
Sheringham Shoal	33.518118	39.476199	0.858097	33.511140	39.467980	0.857918	-0.006978	-0.008219	-0.000179
Thanet	25.595295	47.952843	1.154394	25.589966	47.942859	1.154154	-0.005329	-0.009984	-0.000240
Triton Knoll	10.657219	31.750835	-	10.636370	31.688721	-	-0.020849	-0.062114	-
Walney 1	30.942940	61.862804	-	30.936498	61.849924	-	-0.006442	-0.012880	-
Walney 2	28.787867	58.586178	-	28.781873	58.573980	-	-0.005994	-0.012198	-
Walney 3	13.295389	26.935661	-	13.269379	26.882966	-	-0.026010	-0.052695	-
Walney 4	13.295389	26.935661	-	13.269379	26.882966	-	-0.026010	-0.052695	-
West of Duddon Sands	11.890386	59.272015	-	11.867124	59.156062	-	-0.023262	-0.115953	-
Westermost Rough	24.177108	41.146364	-	24.129810	41.065869	-	-0.047298	-0.080495	-

Demand Tariffs

Demand Residual Tariffs

Half-Hourly (HH) Tariffs

Non-Half-Hourly (NHH) Tariffs

Embedded Export Tariffs (EET)

Demand Tariffs Summary

There are two types of demand, Half-Hourly (HH) and Non-Half-Hourly (NHH). This section shows the tariffs for HH and NHH as well as the tariffs for Embedded Export (EET).

The demand residual banded charges make up majority of the TNUoS demand charge in the form of a non-locational set of daily charges per site across the banding categories and thresholds.

Table 8 Summary of Demand Tariffs

Non-locational Banded Tariffs	2025/26 July	2025/26 November	Change
Average (£/site/annum)	123.115360	131.615496	8.500135
Unmetered (p/kWh/annum)	1.559189	1.730788	0.171598
Demand Residual (£m)	3,992.7	4,224.1	231.4

HH Tariffs (Locational)	2025/26 July	2025/26 November	Change
Average Tariff (£/kW)	6.636305	7.806603	1.170299

EET	2025/26 July	2025/26 November	Change
Average Tariff (£/kW)	2.706248	3.106969	0.400721
AGIC (£/kW)	2.789141	2.791637	0.002496
Embedded Export Volume (GW)	7.484425	7.810774	0.326350
Total Credit (£m)	20.254709	24.267834	4.013125

NHH Tariffs (locational)	2025/26 July	2025/26 November	Change
Average (p/kWh)	0.304276	0.378015	0.073739

Since the publication of the July forecast, both the average HH & NHH demand tariffs have seen an increase. Driven by increases in demand zone 14 as a result of changes to the forecast generation mix. Revenue recovered through the demand residual has increased by £231.4 m with an additional £18.6m to be recovered through the locational elements. Overall total Demand revenue has increased since the July forecast by £250m.

The average HH gross tariff is forecast to be £7.81/kW, an increase of £1.17/kW compared to the July forecast. The average NHH tariff is forecast to be 0.38p/kWh, an increase of 0.07p/kWh compared to the July forecast.

The Embedded Export Volume for the Draft Tariffs has increased since the July forecast by 0.33GW to 7.81GW. The total credit paid out to embedded generators (<100MW) is currently forecast to be £24.27m, an increase of £4.01m. The average Embedded Export Tariff (EET) is now forecast to be £3.11/kW, an increase of £0.40/kW compared to the July forecast.

Table 9 Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	0.389234
7	East Midlands	-	-	2.712561
8	Midlands	2.263138	0.292904	5.054775
9	Eastern	1.542340	0.211744	4.333977
10	South Wales	3.819751	0.459966	6.611388
11	South East	5.036122	0.699604	7.827759
12	London	7.491102	0.797542	10.282739
13	Southern	8.729190	1.129760	11.520827
14	South Western	9.567700	1.368920	12.359337

Demand Residual Tariffs

Since the July forecast, we have updated both the Site counts and consumption data used to allocate the proportion of residual revenue to each charging band. For the first time a full national set of consumption data has been made available to NESO (actual data for October 2023 to September 2024) from the Distribution Network Operators (DNO). This data is now fixed and will remain the same for Final tariffs.

A breakdown of the banding thresholds, consumptions, consumption proportions and site count for the demand residual banded charges can be seen in Table TB of the published tables excel spreadsheet[5]. The residual band thresholds will remain the same for the duration of the RIIO-2 price control period.

Table 10 shows the forecast demand residual tariffs by band. These tariffs will apply to final demand sites in addition the HH or NHH locational charges.

[5] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.

Table 10 Non-Locational demand residual charges

Band		2025/26 July	2025/26 November	Change
Domestic	Tariff - £/Site/Day	0.135823	0.148704	0.012881
LV_NoMIC_1		0.091560	0.170491	0.078931
LV_NoMIC_2		0.332169	0.403074	0.070905
LV_NoMIC_3		0.767145	0.844912	0.077767
LV_NoMIC_4		2.283947	2.300924	0.016977
LV1		4.105523	4.302998	0.197475
LV2		6.983995	7.189576	0.205581
LV3		11.134944	11.288913	0.153969
LV4		25.965876	25.039789	(0.926087)
HV1		21.586225	24.038633	2.452408
HV2		65.139082	69.152197	4.013115
HV3		124.998029	134.115745	9.117716
HV4		319.604356	352.092870	32.488514
EHV1		174.276812	177.027409	2.750597
EHV2		877.000450	816.822572	(60.177878)
EHV3		1,647.447367	1,772.543779	125.096412
EHV4		4,617.682978	4,172.367764	(445.315214)
T-Demand1		632.567787	713.327257	80.759470
T-Demand2		2,125.129762	2,519.052656	393.922894
T-Demand3		5,589.944623	5,997.314639	407.370016
T-Demand4		13,376.044359	14,091.179805	715.135446
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		1.559189	1.730788	0.171598
Demand Residual (£m)		**3992.73**	**4224.09**	**231.36**

On average, Transmission Demand Residual tariffs have increased overall by 6% since our July forecast, in line with the increase in the demand revenue to be collected. Although, there are significant deviations from this across all the Tariff Bands. For the first time a full national set of consumption data has been made available to NESO (actual data for October 2023 to September 2024) from the Distribution Network Operators (DNO).

The deviations from the average 6% increase in line with revenue increases, are due to the proportion of residual revenue assigned to each charging band having moved from a DNO forecast value to actual consumption data.

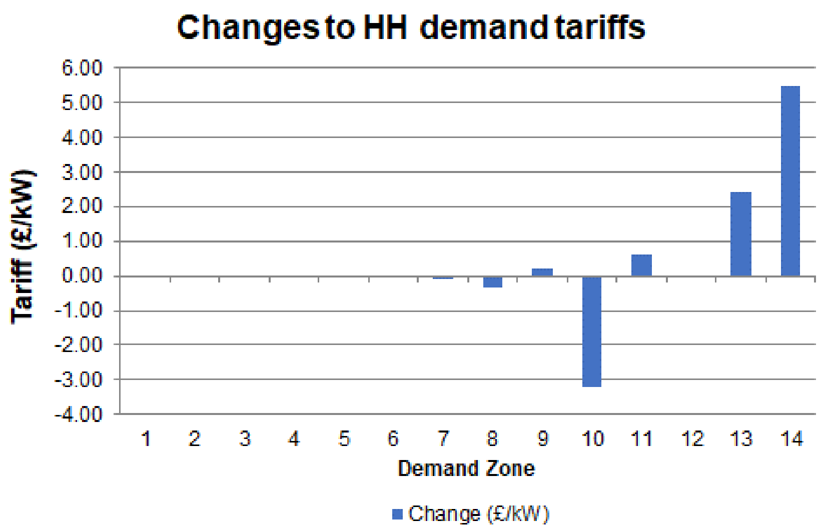
Half-Hourly Demand Tariffs

Table 11 shows the Draft gross HH demand tariffs for 2025/26 compared to the July forecast.

Table 11 Half-Hourly Demand Tariffs

Zone	Zone Name	2025/26 July (£/kW)	2025/26 November (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	0.076687	-	-0.0766870
8	Midlands	2.586633	2.263138	-0.3234950
9	Eastern	1.333956	1.542340	0.208384
10	South Wales	7.005880	3.819751	-3.1861290
11	South East	4.443943	5.036122	0.592179
12	London	7.556494	7.491102	-0.0653920
13	Southern	6.311561	8.729190	2.417629
14	South Western	4.060896	9.567700	5.506804

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, there are fluctuations in tariffs for zones 7 through to 14. These are due to combination of the £0.02/MWkm increase in the forecast Expansion Constant (EC) since July tariffs and changes in the regional Generation mix, which have also had an impact on locational tariffs which make up the HH tariff. It is worth noting that the final set of Nodal demand data was not available in time to be included within this publication and so will be further refined ahead of the Final Tariff publication in January. This means that Locational tariffs will be finalised in January.

The forecast level of gross HH chargeable demand has increased by 0.25GW since July and is currently forecast to be 17.95GW.

Half-Hourly Demand Tariffs for Transmission Connected Users with Multiple DNO's

Where a transmission site has a local GSP which connects to and feeds multiple DNO networks, Demand Tariffs are derived from the average zonal tariffs from the relevant DNO zones. We have created site specific tariffs for transmission connected users that are already connected to, or are due to be connected to, the National Electricity Transmission System at the boundaries of multiple DNO areas in 2025/26.

Table 12 Half-Hourly Demand tariffs for Transmission Connected users with multiple DNO's

		Demand Zone			T-connected Site		
Site Code	Site Name	DNO 1	DNO 2	DNO 3	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	T-Connected Tariff Floored (£/kW)
MELK	MELKSHAM	13	14		0.276924	8.871520	9.148445
BARK	BARKING	9	12		2.094225	2.422496	4.516721
WISD	WILLESDEN	9	12	13	1.961564	3.959313	5.920877

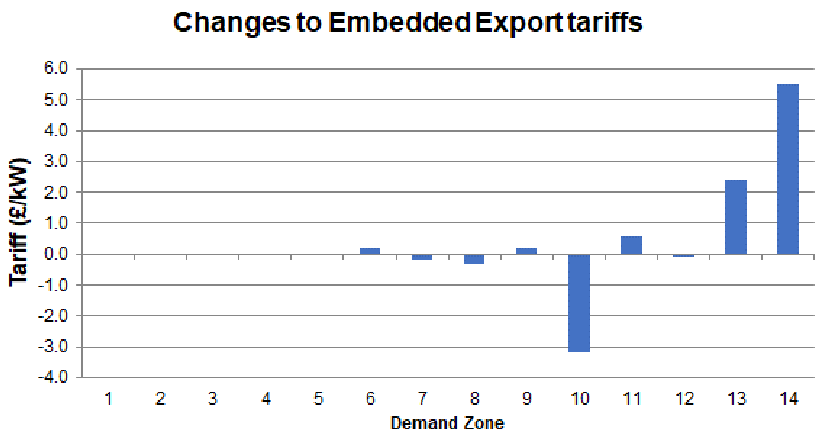
Embedded Export Tariffs (EET)

Table 13 shows the July Forecast Embedded Export tariffs for 2025/26 compared to the November Draft forecast.

Table 13 Embedded Export Tariffs

Zone	Zone Name	2025/26 July (£/kW)	2025/26 November (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.185399	0.389234	0.203835
7	East Midlands	2.865828	2.712561	-0.1532670
8	Midlands	5.375774	5.054775	-0.3209990
9	Eastern	4.123097	4.333977	0.210880
10	South Wales	9.795021	6.611388	-3.1836330
11	South East	7.233084	7.827759	0.594675
12	London	10.345635	10.282739	-0.0628960
13	Southern	9.100702	11.520827	2.420125
14	South Western	6.850037	12.359337	5.509300

Figure 3 Embedded export tariff changes



In this forecast, there has been an increase to the average EET of £0.40/kW versus the July forecast. This is primarily due to a change modelled network flows due to forecasted transmission generation mix and nodal demand data. The changes in locational demand tariffs and the corresponding impact can be seen in Table 26. The Embedded Export Volume has increased since our July forecast to 7.81GW. There has been a slight increase to the Avoided GSP Infrastructure Costs (AGIC) of £0.002/kW to £2.792/kW due to an increase in inflation for 2025/26. The overall impact of these changes has increased the average EET by £0.40/kW to 3.11/kW.

The amount of metered embedded generation produced at Triads by suppliers and embedded generators (<100MW) will determine the amount paid to them through the EET. The money to be paid out through the EET is recovered through demand tariffs, which will affect the price of HH and NHH demand residual tariffs.

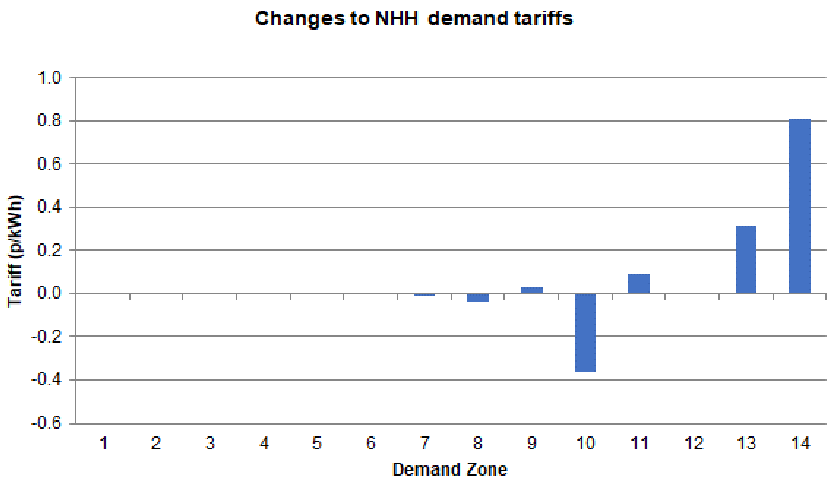
Non-Half-Hourly Demand Tariffs

Table 14 and Figure 4 show the difference in Non-Half-Hourly tariffs between the 2025/26 the July forecast and the November Draft forecast.

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2025/26 July (p/kWh)	2025/26 November (p/kWh)	Change (p/kWh)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	0.009870	-	-0.0098700
8	Midlands	0.333620	0.292904	-0.0407160
9	Eastern	0.180633	0.211744	0.031111
10	South Wales	0.822447	0.459966	-0.3624810
11	South East	0.605997	0.699604	0.093607
12	London	0.798303	0.797542	-0.0007610
13	Southern	0.815929	1.129760	0.313831
14	South Western	0.562408	1.368920	0.806512

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2025/26 is forecast to be 0.38p/kWh, a 0.07p/kWh increase compared to the July forecast. As mentioned above for the HH and Embedded tariffs, the locational element of demand charges has caused fluctuations in the NHH zonal tariffs.

The impact is that Zonal NHH demand revenue recovery has increased by £15.6m since the July forecast.

Overview of Data Inputs

This section explains the changes to the input data which fed into this quarterly forecast process.

Inputs affecting the locational element of tariffs

The locational elements of generation and demand tariffs are based upon:

- Contracted generation
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2025/26 period, which can be found on the TEC register[6]. The contracted TEC volumes are based on the 31 October 2024 TEC register.

Modelled Best View TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the Initial and July forecasts, we forecast our best view of modelled TEC. However, for our November Draft tariffs and January Final tariffs we use the contracted TEC position as published in the TEC register as of 31 October 2024, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2025/26 and liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2025.

Table 15 Contracted, Modelled & Chargeable TEC

	2025/26 Tariffs			
Generation (GW)	**Initial**	**July**	**Draft**	**Final**
Contracted TEC	115.47	113.33	112.27	
Modelled Best View TEC	91.86	108.04	*For input to locational tariffs post 31st October please see Contracted TEC*	
Chargeable TEC	83.15	99.22	94.75	

Adjustments for Interconnectors

When modelling flows on the transmission system in order to set locational tariffs, interconnector flows are not included in the Peak model but are included in the Year

[6] See the Registers, Reports and Updates section at neso.energy/industry-information/connections/reports-and-registers

Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the calculations of chargeable TEC for either the generation or demand charging bases.

The table below reflects the contracted position of interconnectors for 2025/26 as stated in the interconnector register[7] as of 31 October 2024.

Table 16 Interconnectors

			Generation MW			
Interconnector	**Node**	**Interconnected System**	**Generation Zone**	**Transport Model Peak**	**Transport Model Year Round**	**Charging Base**
Auchencrosh	Auchencrosh 275kV Substation	Northern Ireland	10	0	500	0
Britned	Grain 400kV Substation	Netherlands	24	0	1,200	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
ElecLink	Sellindge 400kV Substation	France	24	0	1,000	0
Greenlink	Pembroke 400kV Substation	Republic of Ireland	20	0	504	0
IFA Interconnector	Sellindge 400kV Substation	France	24	0	1,988	0
IFA2 Interconnector	Chilling 400kV Substation	France	26	0	1,100	0
LionLink (EuroLink)	Friston 400kV Substation	Netherlands	18	0	1,600	0
Nemo Link	Richborough 400kV Substation	Belgium	24	0	1,020	0
NS Link	Blyth GSP	Norway	13	0	1,400	0
Viking Link	Bicker Fen 400kV Substation	Denmark	17	0	1,500	0

Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology throughout the price control period. The 2025/26 Expansion Constant is £18.411714/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-T1 value which was set in 2013/14 and will continue to increase in-line with inflation each year. A review of the EC methodology and the expansion factors is ongoing with the industry (CMP315/375), any impact will be included in our forecast publications once the modification has concluded.

Locational Onshore Security Factor

The locational onshore security factor (also called the global security factor), set at 1.76 for the duration of RIIO-2, is applied to locational tariffs. This parameter approximately represents the redundant network capacity to secure energy flows under network contingencies. A guide to the onshore security factor calculation is published on our website: neso.energy/document/183406/download.

[7] See the Registers, Reports and Updates section at neso.energy/industry-information/connections/reports-and-registers

Onshore Substation Tariffs

Local onshore substation tariffs are reviewed and updated at each price control as part of the TNUoS tariff parameter refresh. Once set for the first year of that price control, the tariffs are then indexed by the average May to October CPIH (actuals and forecast), as per the CUSC requirements, for the subsequent years within that price control period.

For this publication, onshore substation tariffs are based on the values set for RIIO-2, inflated by CPIH.

Offshore Local Tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant OFTO. These tariffs were recalculated for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting.

For this publication, offshore local tariffs are based on the values set for RIIO-2 (or at asset transfer, if later), inflated in line with the relevant OFTO's revenue.

Allowed Revenues

The majority of the TNUoS charges look to recover the allowed revenue for the onshore and offshore TOs in Great Britain. It also recovers some other revenue for example, Strategic Innovation Fund and Interconnector revenue recovery or redistribution.

For onshore TOs, National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT), and Scottish Hydro Electric Transmission (SHET), the allowed revenues are subject to Ofgem's price control (RIIO-T2 period spans across 2021/22 – 2025/26). Financial parameters including project spending profiles, rate of return and inflation index are set at the beginning of each price control period. Onshore TOs allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process (AIP).

An overview of revenue to be recovered can be found in Table 18. For more details on the TNUoS revenue breakdown, please refer to Appendix F.

The TOs provide NESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The revenue forecast has been based on preliminary Onshore and Offshore TO submissions in October 2024. The 2025/26 revenue forecast will be updated and finalised by January Final Tariffs based on Onshore and Offshore TO final submissions.

Table 17 Allowed Revenues

£m Nominal	2025/26 TNUoS Revenue			
	Initial Forecast	July Forecast	November Draft	January Final
TO Income from TNUoS				
National Grid Electricity Transmission	2,502.8	2,502.8	2,595.3	-
Scottish Power Transmission	502.9	502.9	530.5	-
SHE Transmission	1,197.3	1,197.3	1,325.4	-
Total TO Income from TNUoS	**4,202.9**	**4,202.9**	**4,451.1**	**-**
Other Income from TNUoS				
Other Pass-through from TNUoS	131.5	82.8	83.8	-
Offshore (plus interconnector contribution / allowance)	946.3	982.7	968.5	-
Total Other Income from TNUoS	**1,077.8**	**1,065.6**	**1,052.3**	**-**
Total to Collect from TNUoS	**5,280.8**	**5,268.5**	**5,503.4**	**-**

Please note these figures are rounded to one decimal place.

Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 18.

In line with the Limiting Regulation, the average TNUoS generation charge, excluding local charges associated with Physical Assets Required for Connection (PARC), should be kept within the range of €0 – 2.50/MWh. We have therefore calculated the expected local charges associated with pre-existing assets and have included this amount when considering the expected average TNUoS generation charges.

The majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for PARC, however, a small part of the TNUoS onshore local charges (approximately £4.89m in this forecast) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is a decrease of £3.8m to local charges associated with pre-existing assets since the July forecast.

Table 18 Generation and demand revenue proportions

Code	Revenue	2025/26 Tariffs Initial Forecast	July Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	
y	Error Margin	31.4%	29.6%	29.6%	
ER	Exchange Rate (€/£)	1.16	1.16	1.16	
MAR	Total Revenue (£m)	5,280.8	5,268.5	5,503.4	
GO	Generation Output (TWh)	209.1	215.3	215.3	
G	% of revenue from generation	21.38%	22.36%	21.13%	
D	% of revenue from demand	78.62%	77.64%	78.87%	
G.R	Revenue recovered from generation (£m)	1,129.1	1,177.9	1,162.8	
D.R	Revenue recovered from demand (£m)	4,151.7	4,090.6	4,340.6	
Breakdown of generation revenue					
	Revenue from the Peak element	121.1	88.2	94.3	
	Revenue from the Year Round Shared element	140.8	182.6	172.4	
	Revenue from the Year Round Not Shared element	186.7	217.8	202.7	
	Revenue from Onshore Local Circuit tariffs	52.4	48.3	46.6	
	Revenue from Onshore Local Substation tariffs	13.5	15.5	14.4	
	Revenue from Offshore Local tariffs	766.2	796.2	780.0	
	Revenue from the adjustment element	-151.8	-170.7	-147.7	
G.MAR	Total Revenue recovered from generation (£m)	1,129.1	1,177.9	1,162.8	
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	12.3	8.7	4.9	

The “gen cap”

Paragraph 14.14.5 (vii) in the CUSC currently limits average annual generation use of system charges to €0 - 2.5/MWh. The revenue that can be recovered from generation is dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy. This revenue limit figure was referred to as the “gen cap” which is part of the UK law (the “Limiting Regulation”). In this report, the term “gen cap” is used to refer to the “upper limit of the Limiting Regulation” in the CUSC.

Exchange Rate

The exchange rate for gen cap calculation is based on the latest Economic and Fiscal Outlook (EFO), published by the Office of Budgetary Responsibility (OBR), and published prior to 31 October. The figure has been finalised, as per OBR’s March EFO, at €1.159905/£.

Generation Output

The forecast output of generation is 215TWh and was updated in our July forecast. This figure is the average of the four scenarios (plus the central case) in the 2024 Future Energy Scenarios and the value is now finalised for 2025/26 tariffs.

Error Margin

The error margin has been updated and finalised in the July forecast, following publication of the outturn of 2023/24 data. The error margin is derived from historical data in the past five whole years (thus for year 2025/26, we use data from years 2019/20 – 2023/24).

Table 19 Generation revenue error margin calculation

Calculation for	2025/26		
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2019/20	-14.6%	-11.5%	-4.1%
2020/21	-13.2%	-10.0%	7.5%
2021/22	4.3%	7.4%	9.5%
2022/23	9.5%	12.6%	13.1%
2023/24	-1.7%	1.5%	-3.5%
Systemic error:	-3.1%		
Adjusted error:		12.6%	13.1%
Error margin =			29.6%

Adjusted variance = the revenue variance - systemic error
Systemic error = the average of all the values in the series
Adjusted error = the maximum of the (absolute) values in the series

Onshore local charges associated with Pre-existing assets

We have published three sets of tariffs relating to pre-existing. These are TNUoS local tariffs associated with pre-existing circuits and pre-existing substation bays, this year we have also included a breakdown of all local assets and their respective PARC/NONPARC components.

The onshore local circuit tariff reflects the impact of the generator on its local network (before reaching the MITS – Main Interconnected Transmission System). If some of the circuits in the local network already existed prior to the generator coming along and applying for connection to the transmission network, and the TO did not identify any need to reinforce these circuits in order to provide adequate capacity for this generator, these circuits are deemed "pre-existing", and the local circuit tariff elements that are associated with these pre-existing assets, are not charges associated with PARC.

Table 20 lists out the onshore local circuit tariff elements associated with pre-existing assets.

Table 20 is only used for the purpose of calculating the gen cap.

Table 20 Onshore local circuit tariff elements associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Project Name	Pre-existing local circuit tariff (£/kW)
A'Chruach Wind Farm	0.000000	Harting Rig Wind Farm	0.000000
Glen App Windfarm	0.000000	Middle Muir Wind Farm	0.000000
Beinneun Wind Farm	0.059206	Aberdeen Offshore Wind Farm	0.000000
Afton Wind Farm	0.000000	Glen Kyllachy Wind Farm	0.000000
Benbrack wind farm	0.435033	Douglas West	0.760252
Blacklaw Extension	0.000000	Enoch Hill	0.000000
Blacklaw	0.000000	Galawhistle Wind Farm	0.000000
Clyde North	0.000000	Broken Cross Windfarm	0.000000
Clyde South	0.000000	Hunterston Energy Storage Facility	0.000000
Corriegarth	0.000000	Kincardine Battery Storage Facility	0.000000
Lochluichart	0.000000	Limekiln	0.000000
Coryton ENERGY	0.000000	Cumberhead West Wind Farm	0.000000
Cruachan	0.000000	Shepherds Rig Wind Farm	-0.099838
Dersalloch Wind Farm	0.000000	Viking Wind Farm	0.000000
Dinorwig	0.000000	Dorenell Windfarm	0.000000
Aberarder Wind Farm	0.760252	Aikengall IIa Wind Farm	0.000000
Edinbane Windfarm	0.000000	Crossdykes	0.000000
Ewe Hill	0.000000	Cumberhead	0.000000
Fallago Rig Wind Farm	0.000000	Douglas West Extension	0.000000
Carraig Gheal Wind Farm	5.355269	Gateway Energy Centre Power Station	0.000000
Ffestiniog	0.000000	Kennoxhead Wind Farm Extension	2.638075
Foyers	0.000000	Kype Muir	0.000000
Hartlepool	0.000000	Sanquhar Wind Farm	0.895245
Marchwood	0.000000	Dalquhandy Wind Farm	0.000000
Pen Y Cymoedd Wind Farm	0.000000	Sandy Knowe Wind Farm	0.000000
Rocksavage	0.000000	Stranoch Wind Farm	2.636979
Saltend	0.000000	Twentyshilling Wind Farm	0.000000
SAGE Solar	0.000000	Whiteside Hill Wind Farm	0.000000
Spalding	0.000000	Windy Rig Wind Farm	0.000000
Stronelairg	0.251713	Windy Standard II (Brockloch Rig) Wind F	0.000000
Aikengall II Windfarm	0.000000	Pencloe Windfarm	0.000000
Whitelee Extension	0.000000	Sanquhar II Wind Farm	5.720751
Bhlaraidh Wind Farm	0.000000	Windy Standard III Wind Farm	0.000000

Aggregated pre-existing TEC (MW)	14,097

Onshore local substation tariffs reflect the cost of accommodating the generator to its local substation. It is very rare for generators to have local substation tariff associated with pre-existing assets, as usually each generator has triggered its own dedicated bay at the local substation.

Table 21 lists out the onshore local substation tariffs associated with pre-existing assets.

Table TC in the tables file gives a breakdown of all local assets and their respective PARC/NONPARC components.

Table 21 Onshore local substation tariffs associated with pre-existing assets

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.179380	37.2
Toddleburn Wind Farm	0.179380	

Charging Bases for 2025/26

Generation

The forecast generation charging base is less than contracted TEC. It excludes interconnectors, which are not chargeable, and generation that we do not expect to be chargeable during the charging year due to closure, termination or delay in connection. It also includes any generators that we believe may increase their TEC.

We are unable to break down our best view of generation as some of the information used to derive it could be commercially sensitive.

The generation charging base for 2025/26 tariffs is forecast at 94.75GW, which is a decrease of 4.47GW since the Initial forecast. It is based on our internal view of what generation we expect to connect next financial year.

For the Final Tariffs (as per these Draft tariffs), in line with the CUSC, we will use the contracted TEC position as of 31 October 2024 to set locational tariffs in the Transport model. Our best view is used to set the adjustment tariff in the Tariff model.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated for 2025/26.

To forecast chargeable HH and NHH demand and EET volumes, we use a Monte Carlo modelling approach. This incorporates our latest data including:

- Historical gross metered demand and embedded export volumes (April 2021 - August 2024)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

With recent historical trends and forward-looking assumptions, demand volumes are forecast to plateau over the next couple of years. Adjustments have been made in our forecast since the July forecast for 2025/26 based on the latest demand outturn data up to end of August 2024. Please refer to table TAA in the published tables excel spreadsheet[8] for a detailed breakdown of the changes to the demand charging bases.

Table 22 Charging Bases

	2025/26 Tariffs			
Charging Bases	**Initial**	**July**	**Draft**	**Final**
Generation (GW)	83.15	99.22	94.75	
NHH Demand (4pm-7pm TWh)	23.06	23.29	22.87	
Gross charging				
Total Average Gross Triad (GW)	47.43	47.45	47.49	
HH Demand Average Gross Triad (GW)	17.21	17.70	17.95	
Embedded Generation Export (GW)	7.48	7.48	7.81	

Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the draft version of the 2025/26 ALFs. ALFs are explained in more detail in Appendix D of this report, and the full list of power station ALFs are available on the NESO website[9].

[8] Please see the **Error! Reference source not found.**Numerical Data section of 'Tools and supporting information' f or the link to the published tables excel spreadsheet.

[9] neso.energy/document/348336/download

Generation adjustment and demand residual

Under the existing CUSC methodology, the adjustment and residual elements of tariffs are calculated using the formulae below.

Adjustment Tariff = (Total Money collected from generators as determined by G/D split less money recovered through locational tariffs) divided by the total chargeable TEC

$$A_G = \frac{G.R - Z_G}{B_G}$$

Where:

A_G is the adjustment tariff (£/kW)

G is the proportion of TNUoS revenue recovered from generation (the G/D split percentage)

R is the total TNUoS revenue to be recovered (£m)

Z_G is the TNUoS revenue recovered from generation locational tariffs (£m), including wider zonal tariffs and project-specific local tariffs

B_G is the generator charging base (GW)

A_G cannot be positive and is capped at 0.

Demand Residual Charges

The demand residual revenue is recovered by a p/site/day charge on final demand users (both HH and NHH), based on site specific banded charges which came into effect in April 2023.

Each final demand site is allocated to a residual charging band that is based on its capacity or annual energy consumption. The charge is non-locational so all sites within the same band pay the same demand residual tariff regardless of which demand zone they are in.

Site counts across the forecast horizon have been kept static, except for the domestic site count which is forecast to continue to rise.

Demand customers are also liable for the locational elements of demand tariffs, based on their triad demand for HH demand or their aggregated annual consumption during 4-7pm each day for their NHH demand.

Table 23 Residual & Adjustment components calculation

	Component	2025/26 Tariffs Initial	July	Draft	Final
G	Proportion of revenue recovered from generation (%)	21.38%	22.36%	21.13%	
D	Proportion of revenue recovered from demand (%)	78.62%	77.64%	78.87%	
R	Total TNUoS revenue (£m)	5,280.8	5,268.5	5,503.4	
Generation revenue breakdown (without adjustment)					
ZG	Revenue recovered from the wider locational element of generator tariffs (£m)	448.67	488.64	469.43	
O	Revenue recovered from offshore local tariffs (£m)	766.2	796.2	780.0	
LG	Revenue recovered from onshore local substation tariffs (£m)	13.5	15.5	14.4	
SG	Revenue recovered from onshore local circuit tariffs (£m)	52.4	48.3	46.6	
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	12.3	8.7	4.9	
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	
	Error Margin	31.4%	29.6%	29.6%	
	Exchange Rate (€/£)	1.16	1.16	1.16	
	Total generation Output (TWh)	209.11	215.27	215.27	
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	309.19	326.76	326.76	
	Adjustment Revenue (£m)	-151.82	-170.67	-147.69	
BG	Generator charging base (GW)	83.15	99.22	94.75	
AdjTariff	Generator adjusment tariff (£/kW)	-1.83	-1.72	-1.56	
Gross demand residual					
RD	Demand residual (£m)	4,038.8	3,992.7	4,224.1	
ZD	Revenue recovered from the locational element of demand tariffs (£m)	133.60	117.45	140.10	
EE	Amount to be paid to Embedded Export Tariffs (£m)	-21.2	-20.3	-24.3	
BD	Demand Gross charging base (GW)	47.4	47.4	47.5	

Tools and supporting information

We would like to ensure that customers understand the current charging arrangements and the reasons why tariffs change. If you have specific queries on this forecast, please contact us using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

Charging webinars

We will be hosting a webinar for the Draft Forecast on Wednesday 11 December. We will be sending out a communication to those who subscribe to our updates via the NESO website, providing details on the upcoming webinar and how to register. For any questions, please see our contact details below.

Charging model copies available

If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website:

neso.energy/document/348401/download

This data can also be accessed via our Data Portal:

neso.energy/data-portal/transmission-network-use-system-tnuos-tariffs

Please allow up to two weeks after the publication for the data portal to be updated.

Contact Us

We welcome feedback on any aspect of this document and the tariff setting processes.

Do let us know if you have any further suggestions as to how we can better work with you to improve the tariff forecasting process.

Our contact details:

Email: TNUoS.Queries@nationalenergyso.com

Appendix A: Background to TNUoS charging

Background to TNUoS charging

NESO sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission investment cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, NESO determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: Peak Demand and Year Round, where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, for example, voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions, which means that they reflect the cost of new assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

TNUoS tariffs consist of two components: locational based charges that vary by zone, and non-locational or 'residual' charges. Residual charges ensure complete revenue recovery for transmission owners (as the Price Control framework). The TNUoS methodology determines the proportion of revenue to be collected from demand and generation users. For generators, the locational and adjustment tariff elements are combined into a single zonal tariff, referred to as the wider zonal generation tariff. Demand charges for both Half Hourly (HH) and Non-Half Hourly (NHH) customers are based on location and vary across demand zones. Additionally, with the implementation of Transmission Demand Residual bandings and allocation, a separate daily site charge applies to final demand based on specific usage bands.

For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the main interconnected transmission system (MITS), the cost of local circuits that the generator uses to export onto the MITS. This allows the charges to reflect the cost and design of local connections and vary from project to project. For offshore generators, these local charges reflect approved revenue allowances.

Generation charging principles

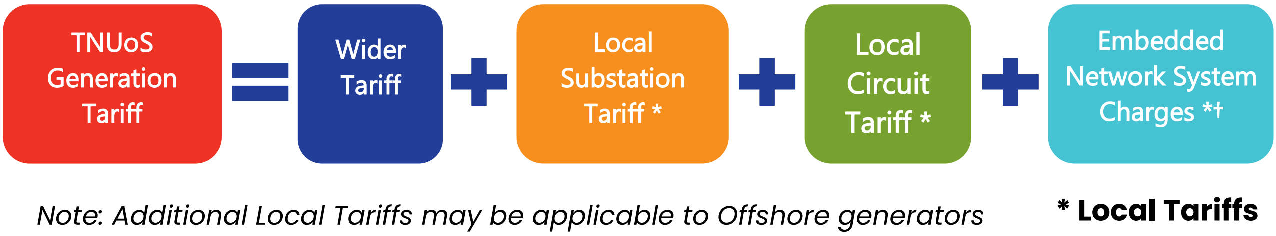
Transmission connected generators (and embedded generators with TEC ≥ 100 MW) are subject to the generation TNUoS charges.

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC

(Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to export onto the transmission network.

Under the current methodology there are 27 generation zones, and each zone has four tariffs. Liability for each tariff component is shown below:

TNUoS tariffs are made up of two general components, the **Wider tariff**, and **local tariffs**.



The Wider tariff is set to reflect the costs incurred by the generator for the use of the whole system, whereas the local tariffs are for the use of assets in the immediate vicinity of the connection site.

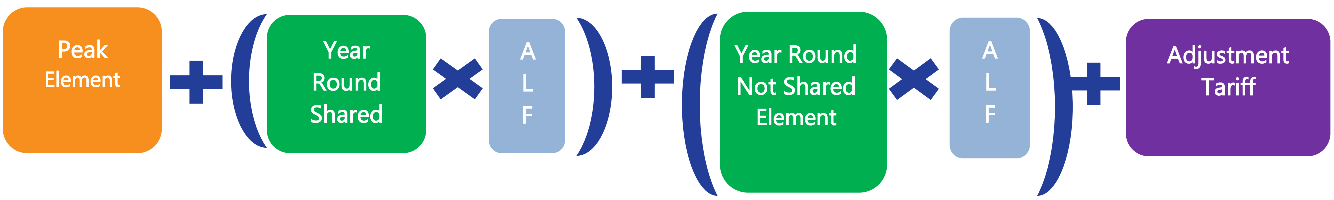
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

The Wider tariff is made up of four components, two of which may be multiplied by the generator's specific Annual Load Factor (ALF), depending on the generator type.

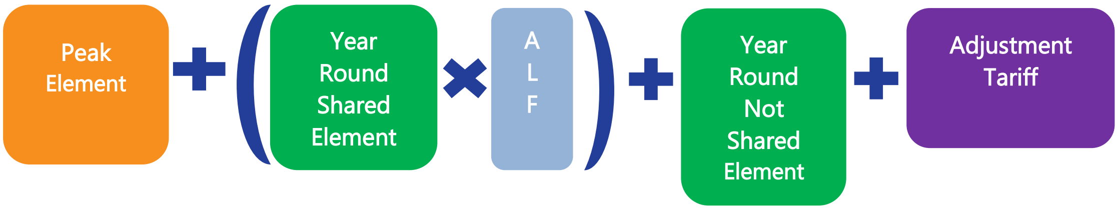
Conventional Carbon Generators

(for example: Biomass, CHP, Coal, Gas, Pumped Storage, Battery)



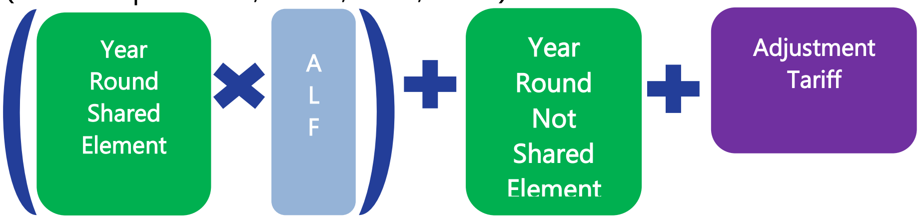
Conventional Low Carbon Generators

(for example: Hydro, Nuclear)



Intermittent Generators

(for example: Wind, Wave, Tidal, Solar)



The **Peak** element reflects the cost of using the system at peak times. This is only paid by conventional and peaking generators; intermittent generators do not pay this element. The **Year Round Shared** and **Year Round Not Shared** elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular zone respectively.

ALFs are calculated annually using data available from the most recent charging year. Any generator with fewer than three years of historical generation data will have any gaps filled using the generic ALF calculated for that generator type.

The **Adjustment Tariff** is a flat rate for all generation zones which adds a non-locational charge (which may be positive or negative) to the Wider TNUoS tariff, to ensure that the correct amount of aggregate revenue is collected from generators as a whole.

The adjustment tariff is also used to ensure generator charges are compliant with the Limiting Regulation. This requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average.

Local substation tariffs

A generator will have a charge depending on the first onshore substation on the transmission system to which it connects. The cost is based on the voltage of the substation, whether there is a single or double ('redundancy') busbar, and the volume of generation TEC connected at that substation.

Local onshore substation tariffs are set at the start of each TO financial regulatory period and increased by CPIH for each year within the price control period.

Local circuit tariffs

If the first onshore substation which the generator connects to is categorised as a MITS (Main Interconnected Transmission System) node in accordance with CUSC 14.15.33, then there is no Local Circuit charge. Where the first onshore substation is not classified as MITS node, there will be a specific circuit charge for generators connected at that location.

Embedded network system charges

If a generator is not connected directly to the transmission network, they need to have a BEGA[10] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[11] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Transmission-connected offshore generators connecting to an embedded OFTO may need to pay an Embedded Transmission Use of System charge through TNUoS tariffs to cover DNO charges that form part of the OFTO's tender revenue stream.

Click here to find out more about DNO regions.

Offshore local tariffs

Where an offshore generator's transmission assets have been transferred to the ownership of an OFTO (Offshore Transmission Owner), there will be additional **Offshore substation** and **Offshore circuit** tariffs specific to that Offshore Generator.

Billing

Generation TNUoS is an annual liability and costs are calculated on the highest level of TEC held by the generator during the year. (A TNUoS charging year runs from 1 April to 31 March). This means that if a generator holds 100MW in TEC from 1 April to 31 January, then 350MW from 1 February to 31 March, the generator will be charged for 350MW of TEC for that charging year.

The calculation for TNUoS generator monthly invoice is as follows:

$$\frac{((TEC \times TNUoS\ Tariff) - TNUoS\ charges\ already\ paid)}{Number\ of\ months\ remaining\ in\ the\ charging\ year}$$

[10] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: neso.energy/industry-information/connections

[11] Distribution network Use of System charges

All tariffs are in £/kW of contracted TEC held by the generator.

TNUoS charges are billed on the first of each calendar month.

Generators with negative TNUoS tariffs

Where a generator's specific tariff is negative, the generator will be paid during the year based on their highest TEC during that year. After the end of the year, there is a reconciliation, when the true amount to be paid to the generator is recalculated.

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

For more details, please see CUSC section 14.18.13–17.

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers have applicable tariffs for gross HH demand and embedded export volumes individually rather than being netted. NHH customers have another tariff which is also applied to HH customers in measurement class F and G. Since April 2023, the TNUoS demand residual is charged separately to all final demand. Where a transmission site has a local GSP which connects to and feeds multiple DNO networks, Demand Tariffs will be derived from the average zonal tariffs from the relevant DNO zones.

HH gross demand tariffs

HH gross demand tariffs are made up of locational charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year[12]. They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[13].

Embedded Export Tariffs (EET)

The EET is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

[12] neso.energy/industry-information/charging/tnuos-charges#Triads-data
[13] neso.energy/document/130641/download

This tariff contains the locational demand elements and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW to avoid negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through the demand residual tariffs.

Customers must submit forecasts for both HH gross demand and embedded export volumes. Customers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon (up to 16 months after the financial year in question).

For more information on forecasts and billing, please see our guide for new suppliers on our website[14].

Embedded generators (<100MW CVA registered) will receive payment following the reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by NESO. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.

Note: HH demand and embedded export is charged at the GSP group, where the transmission network connects to the distribution network, or directly to the customer in question.

NHH demand tariffs

NHH metered customers are charged based on their demand usage between 16:00 – 19:00 every day of the year. Suppliers must submit forecasts throughout the year of their expected demand volumes in each demand zone. The tariff is charged on a p/kWh basis.

Suppliers are billed against these forecast volumes, and two reconciliations of the amounts paid against their actual metered output take place, the second of which is once the final metering data is available from Elexon up to 16 months after the financial year in question.

Demand residual tariffs

Final demand sites are charged based on the residual band they have been allocated to. The demand residual banded charges now make up majority of the TNUoS demand charge in the form of a set of daily charges per site in each of the residual charging bands, this is a non-locational charge.

[14] neso.energy/industry-information/charging/charging-documentation

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

The charging methodology can be changed through modifications to the CUSC and the licence.

This section focuses on specific CUSC modifications which may impact on the TNUoS tariffs for financial year 2025/26.

More information about current modifications can be found at the following location:

neso.energy/industry-information/codes/connection-and-use-system-code-cusc/cusc-modifications

A summary of the modifications already in progress, which could potentially affect 2025/26 TNUoS tariffs and their status, are listed below.

Table 24 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Implementation
CMP288	Explicit charging arrangements for customer delays and backfeeds	Potential impact on non-locational tariffs only	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
CMP315/375	Expansion Constant & Expansion Factor Review	Affects TNUoS locational tariffs for generators and demand users	
CMP316/397	TNUoS Arrangements for Co-located Generation Sites	Affects TNUoS locational tariffs	
CMP418	Refine the allocation of Static Var Compensators (SVC) costs at OFTO transfer	Seeks to remove cost of certain reactive compensation equipment from the Generators annual local offshore tariff and include it in the general TNUoS via the demand residual	
CMP426	TNUoS charges for transmission circuits identified for the HND to add capacity across boundaries	Ensuring the purpose and function of circuits classified as boundary reinforcement are considered when determining the appropriate TNUoS tariff and users the costs are recovered from	

Modifications directed for implementation:			
CMP392	Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation	Provides stakeholders with legal certainty and transparency of the methodology including the calculation and the output of the calculation	1 April 2025
CMP411	Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies	Introduce Anticipatory Investment (AI) and a mechanism for the recovery of AI costs within the Section 14 charging methodologies	1 April 2025
CMP424	Amendments to Scaling Factors used for Year round TNUoS charges	Seeks to introduce a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of Year Round Background tariff calculation	1 April 2025
CMP430	Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme	To rectify defects relating to demand locational TNUoS charging that will become apparent during the migration phase of the MHHS Programme	1 April 2025

Please note that we have not included the CUSC modifications which may have a small or localised impact on the TNUoS charge in our forecast or in the above list.

The TNUoS charging methodology is also subject to change under fundamental review programmes. A few of the recent and future fundamental reviews or Significant Code Reviews are discussed in the Charging methodology changes section of this report. To effect change to the charging methodology, these review programmes would result in CUSC modifications being raised.

Appendix C: Breakdown of locational HH and EE tariffs

Locational components of demand tariffs

The following tables show the locational components of the HH demand charge (Peak and Year-Round) and the changes between forecasts. The residual is added to these values to give the overall HH tariff.

For the Embedded Export Tariffs (EET), the demand locational elements (peak security and year-round) are added together. The AGIC is then also added, and the resulting tariff is floored at zero to avoid negative tariffs (charges).

Table 25 Location elements of the HH demand tariff for 2025/26

Demand Zone		2025/26 July		2025/26 November		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	1.034812	- 34.711603	-0.064369	-33.424399	- 1.099181	1.287203
2	Southern Scotland	0.087576	- 24.933077	-0.814464	-22.688930	- 0.902039	2.244147
3	Northern	- 0.636916	- 11.668914	-1.400001	-10.070967	- 0.763085	1.597947
4	North West	1.534968	- 6.431449	-0.305832	-5.210810	- 1.840800	1.220639
5	Yorkshire	0.492905	- 4.648049	-0.506379	-3.353749	- 0.999284	1.294299
6	N Wales & Mersey	0.263436	- 2.867178	-1.524935	-0.877469	- 1.788371	1.989709
7	East Midlands	- 0.025789	0.102476	-1.379039	1.299963	- 1.353249	1.197487
8	Midlands	0.111739	2.474894	-1.365342	3.628480	- 1.477081	1.153586
9	Eastern	0.382478	0.951478	0.596787	0.945553	0.214309	- 0.005925
10	South Wales	- 3.986884	10.992764	-5.299242	9.11899	- 1.312358	- 1.873771
11	South East	- 0.385751	4.829694	2.857412	2.178710	3.243163	- 2.650984
12	London	1.726334	5.830160	3.591662	3.899440	1.865328	- 1.930720
13	Southern	- 0.250290	6.561851	1.696243	7.032946	1.946533	0.471095
14	South Western	- 4.231984	8.292880	-1.142394	10.710094	3.089590	2.417214

Table 26 Elements of the Embedded Export Tariff for 2025/26

Demand Zone		2025/26 July		2025/26 November		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	- 33.676790	2.789141	-33.488768	2.791637	0.188022	0.002496
2	Southern Scotland	- 24.845502	2.789141	-23.503394	2.791637	1.342108	0.002496
3	Northern	- 12.305830	2.789141	-11.470968	2.791637	0.834861	0.002496
4	North West	- 4.896481	2.789141	-5.516642	2.791637	- 0.620160	0.002496
5	Yorkshire	- 4.155143	2.789141	-3.860128	2.791637	0.295015	0.002496
6	N Wales & Mersey	- 2.603742	2.789141	-2.402403	2.791637	0.201338	0.002496
7	East Midlands	0.076687	2.789141	-0.079076	2.791637	- 0.155762	0.002496
8	Midlands	2.586633	2.789141	2.263138	2.791637	- 0.323495	0.002496
9	Eastern	1.333956	2.789141	1.542340	2.791637	0.208384	0.002496
10	South Wales	7.005880	2.789141	3.819751	2.791637	- 3.186128	0.002496
11	South East	4.443943	2.789141	5.036122	2.791637	0.592179	0.002496
12	London	7.556494	2.789141	7.491102	2.791637	- 0.065392	0.002496
13	Southern	6.311561	2.789141	8.729190	2.791637	2.417628	0.002496
14	South Western	4.060896	2.789141	9.567700	2.791637	5.506804	0.002496

Appendix D: Annual Load Factors

ALFs

ALFs are used to scale the Shared Year-Round element of tariffs for each generator, and the Year Round Not Shared for Conventional Carbon generators, so that each has a tariff appropriate to its historical load factor.

For the purposes of this forecast, we have used the draft version of the 2025/26 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2019/20 to 2023/24. Generators which commissioned after 1 April 2021 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is incorporated to create three complete years from which the ALF can be calculated. Generators expected to commission during 2025/26 also use the Generic ALF (in whole or in combination with their actual data) until they have three complete years' worth of operational data to use in the calculations.

The specific and generic ALFs that will apply to the 2025/26 TNUoS Tariffs have been updated with the recently released Draft ALFs. These are available for industry consultation until Friday 20 December, after which they will become final. The specific and generic ALFs, as used in this forecast, are published here, with specific ALFs in excel format here.

Generic ALFs

Table 27 Generic ALFs

Technology	Generic ALF
Battery	3.8884%
Biomass	42.9869%
CCGT_CHP	42.3027%
Coal	29.0586%
Gas_Oil	0.8252%
Hydro	39.6894%
Nuclear	55.6863%
Offshore_Wind	48.2176%
Onshore_Wind	41.5111%
Pumped_Storage	9.4949%
Reactive_Compensation	0.0000%
Solar	10.8000%
Tidal	13.2000%
Wave	2.9000%

Please note: ALF figures for Wave, Tidal and Solar technology are generic figures published by NESNZ due to insufficient metered data being available.

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Appendix E: Contracted Generation

The contracted TEC volumes are used to set locational tariffs; however, we also model our best view of contracted TEC which also feeds into the Tariff model to set the generation adjustment tariff. We are unable to share our best view of contracted TEC in this report, as they may be commercially sensitive.

The contracted generation used in the Transport model is now fixed using the TEC register as of 31 October 2024, as required by the CUSC 14.15.6 and no further changes to Contracted TEC will be made.

Table 28 shows the contracted generation changes notified since the July forecast using data from the October 2024 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Akku Tealing Battery Storage	500	TEAL20	5
Arecleoch Windfarm Extension	-72.8	AREX10	10
Axminster - New Connection	-50	AXMI40_SEP	26
Bradford West 100MW	-100	BRAW20	15
Braintree (Tertiary)	-50	BRAI4A	24
Bramford (Tertiary)	57	BRFO40	18
Bramford Tertiary	-7	BRFO40	18
Bramley (tertiary)	57	BRLE40	25
Bridgwater 2 (tertiary) - New Conn	-54	BRWA4A	26
Broken Cross Windfarm	48	BROT10	11
Bustleholme	7	BUST20	18
Capenhurst Tertiary Connection	57	CAPE20	16
Cleve Hill Solar Park	350	CLEH40	24
Cowley (Tertiary)	57	COWL40	25
Deeside Power Station	-1	CONQ40	16
Dorenell Battery	37.5	CAIN20	1
Drax	-190	DRAX40	15
Enderby (Akira)	57	ENDE40	18
Enoch Hill	69	ENHI10	10
Flash Solar Farm	-360	STAY40	16
Fleet EGH (Tertiary)	-50	FLEE40	25
Grain North Power Station	49.99	GRAI40	24
Grain South Power Station	50	GRAI40	24
Harestanes	-38.3	HARE10	12
Heysham Power Station	-25	HEYS40	14
Highview Hunterston East Cryobattery	-99.8	HUNE40	10
Hinkley Point C	-1670	HINP40	26
Hirwaun Power Station	299	RHIG40	21
Hunterston	1020	HUER40	10
Immingham	50	HUMR40	15
JBM Solar 13 - Melksham	50	MELK40_SEP	22
JG Pears	17	HIGM40	16
Kingsnorth	-50	KINO40	24
Lakeside Energy Drax	99.9	DRAX40	15
Landulph	50	LAND4A	27
Ratcliffe on Soar	-796.3	RATS40	18
Lister Battery (formerly Lister Drive)	57	LISD20	15
Longfield Solar	-500	BULL40	24
Melksham (Tertiary)	57	MELK40_SEP	22
Neart Na Gaoithe Offshore Wind Farm	448	CRYR40	11
Norwich	-50	NORM40	18
Ocker Hill Tertiary Connection	57	OCKH20	18
Oldbury (Tertiary)	-50	OLDB4A	18
Pencloe Windfarm	4	BLAH10	10
Powersite @ Drakelow	380	DRAK40	18
Rayleigh 1 Tertiary	49.9	RAYL40	24
Seabank (Tertiary)	50	SEAB40	22
Strathy South Wind	-207.6	STRW10	1
Strathy Wood	-64	STWO10	1
Sundon	39.9	SUND40	18
Sundon Pivoted Power	50	SUND40	18
Tees CCPP	150	GRST2A	13
Walpole	50	WALP40_EME	17
Walpole 1 (Tertiary)	57	WALP40_EME	17
Warley	-57	WARL20	24
Warley (tertiary)	49.9	WARL20	24
Whitelee Extension	32	WLEX20	10
Zenobe Blackhillock 300 MW	200	BLHI20	1
Bird Grove/Rownall	-57	CELL40_SPM	18
Dungeness B	-1120	DUNG40	24
Tottenham	-50	TOTT20	23

Appendix F: Transmission Company Revenues

Transmission Owner revenue forecasts

The revenue forecast has been based on preliminary data submissions received by Onshore and Offshore TOs in October 2024. The 2025/26 revenue forecast will be updated and finalised by January Final Tariffs based on Onshore and Offshore TOs 25/26 final submissions. In addition, there are some pass-through items that are to be collected by NESO via TNUoS charges, including the Strategic Innovation Fund (SIF) and contributions made from Interconnectors.

Revenue for offshore networks is included with forecasts by NESO where the Offshore Transmission Owner has yet to be appointed.

Notes:

All monies are quoted in millions of pounds, accurate to two decimal places and are in nominal 'money of the day' prices unless stated otherwise.

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. NESO and TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither NESO nor TOs accept or assume responsibility for the use of this information by any person or any person to whom this information is shown or any person to whom this information otherwise becomes available.

NESO TNUoS revenue pass-through items forecasts

The allowed TNUoS revenue from the onshore TO's (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) and OFTOs is collected by NESO and passed through to those parties.

NESO also collects the Strategic Innovation Fund (SIF) and passes through the money to network licensees (including TOs, OFTOs and DNOs), in addition to a few other pass-through items. The revenue breakdown table below (table 29) shows details of the pass-through TNUoS revenue items under NESO's licence conditions.

Since the July forecast, there has been a significant increase in TO Allowed Revenues and a small decrease of OFTO and Interconnector payments. These values will be updated in the January Final forecast.

Table 29 NESO revenue breakdown

Term	NESO TNUoS Other Pass-Through			
	Initial Forecast	July Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.69	0.67	0.67	
Network Innovation Competition Fund (NICFt)	0.00	0.00	0.00	
Strategic Innovation Fund (SIFt)	85.01	85.01	85.01	
The Adjustment Term (ADJt)	0.00	-40.75	-39.82	
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	946.31	982.73	968.50	
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	
Termination Sums (TSt)	0.00	0.00	0.00	
NGET revenue pas-through (NGETTOt)*	2,502.79	2,502.79	2,595.27	
SPT revenue pass-through (TSPt)	502.87	502.87	530.47	
SHETL revenue pass-through (TSHt)	1,197.29	1,197.29	1,325.36	
NESO Bad debt (BDt)	3.12	0.03	0.03	
NESO other pass-through items (LFt + ITCt etc)	42.69	37.88	37.88	
NESO legacy adjustment (LARt)	0.00	0.00	0.00	
Total	**5,280.77**	**5,268.50**	**5,503.36**	

Onshore TOs (NGET, SPT and SHET) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) provided us with their preliminary revenue breakdown in October 2024 as required by STCP 24-1. There has been a £234.85m increase in the TO revenue (NGET, +£92.48m, SPT, +£27.6m and SHET, +£128.06m). These figures remain highly indicative.

For SPT, revenue increases are due to the inclusion of additional Total Expenditure (Totex) allowances for uncertainty mechanisms such as Medium Sized Investment Projects (MSIP), Large Onshore Transmission Investments (LOTI) & Accelerated Strategic Transmission Investment (ASTI) and the associated knock-on impact in the Operating Expenditure (Opex) escalator. Further uplift due to the inclusion of actual ODI (Output Delivery Incentives) Values for 23/24 with the main driver being the extension of the SO-TO ODI and associated earned revenues in 23/24, offset by the movement in OBR inflation forecasts between November 23 (pricing) & March 24 inflation.

Movement in NGET revenue was due to increases in Totex costs and allowances predominantly related to re-openers associated to ASTI programme activities and MSIP, truing up under collection of 2024/25 revenue and small changes in the Adjustment Term to actualise 2023/24 performance.

SHET's Adjustment Term for the 2025/26 revenue has increased and accounts for updated Capital Expenditure (Capex) figures reflecting the latest information provided for ASTI and LOTI projects. These projects are still in the early development stages and are subject to due diligence before the final submission expected in January 2025.

All TO figures will be updated for the January Final Tariffs.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2025/26 is forecast to be £1.01bn, a decrease of £14.2m since the July forecast. Revenues have been adjusted using the latest RPI and CPI data (as part of the calculation of each OFTO's inflation term, as defined in the relevant OFTO licence).

Interconnector adjustment

TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework, and Interconnectors' Cap & Floor framework.

Updates to the Interconnector Adjustment forecast were updated based on figures submitted by Interconnectors in October 2024. Any further updates will be included in the January forecast.

Table 30 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	
Inflation		PI_t	372.27	372.27	368.43	
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	1,952.30	1,952.30	1,987.06	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	38.91	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**2,565.33**	**2,565.33**	**2,622.96**	
SONIA	B1	It-1	0.05	0.05	0.05	
Allowed Revenue	B2	AR_{t-1}	2,022.91	2,022.91	2,001.77	
Recovered Revenue	B4	RR_{t-1}	2,022.91	2,022.91	1,969.55	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**34.20**	
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	
Legacy MOD	C2	$LMOD_t$	-62.54	-62.54	-61.90	
Legacy K correction	C3	LK_t	0.00	0.00	0.00	
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	0.00	0.00	0.00	
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**-62.54**	**-62.54**	**-61.90**	
Site Rental Charges			**0.00**	**0.00**	**0.00**	
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**2,502.79**	**2,502.79**	**2,595.27**	

Table 31 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	
Inflation		PI_t	372.27	372.27	368.43	
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	392.65	392.65	417.84	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.04	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**515.94**	**515.94**	**543.41**	
SONIA	B1	It-1	0.05	0.05	0.05	
Allowed Revenue	B2	AR_{t-1}	0.00	0.00	449.18	
Recovered Revenue	B4	RR_{t-1}	0.00	0.00	449.18	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**0.00**	
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	
Legacy MOD	C2	$LMOD_t$	-13.17	-13.17	-13.04	
Legacy K correction	C3	LK_t	0.00	0.00	0.00	
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	0.09	0.09	0.09	
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**-13.08**	**-13.08**	**-12.94**	
Site Rental Charges			**0.00**	**0.00**	**0.00**	
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**502.87**	**502.87**	**530.47**	

Table 32 SHET revenue breakdown

Transmission Revenue Forecast			SHE Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	
Inflation		PI_t	372.27	372.27	368.43	
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	898.91	898.91	1,003.52	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-3.99	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**1,181.18**	**1,181.18**	**1,301.03**	
SONIA	B1	It-1	0.05	0.05	0.05	
Allowed Revenue	B2	AR_{t-1}	781.07	781.07	780.69	
Recovered Revenue	B4	RR_{t-1}	781.07	781.07	772.79	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**8.38**	
Legacy pass-through	C1	LP_t	0.00	0.00	0.00	
Legacy MOD	C2	$LMOD_t$	16.12	16.12	15.95	
Legacy K correction	C3	LK_t	0.00	0.00	0.00	
Legacy TRU term	C4	$LTRU_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	0.00	0.00	0.00	
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**16.12**	**16.12**	**15.95**	
Site Rental Charges			**0.00**	**0.00**	**0.00**	
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**1,197.29**	**1,197.29**	**1,325.36**	

Table 33 Offshore Revenues

Offshore Transmission Revenue Forecast (£m)	Year					
Regulatory Year	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**Notes**
Barrow	6.7	7.0	7.8	8.5	8.9	Current revenues plus indexation
Gunfleet	8.4	8.7	9.7	10.7	11.1	Current revenues plus indexation
Walney 1	15.3	15.6	17.8	19.4	20.2	Current revenues plus indexation
Robin Rigg	9.4	9.8	10.9	12.0	12.4	Current revenues plus indexation
Walney 2	15.1	16.3	18.3	20.0	20.9	Current revenues plus indexation
Sheringham Shoal	23.4	24.2	26.7	29.5	30.7	Current revenues plus indexation
Ormonde	14.1	14.7	16.2	17.9	18.6	Current revenues plus indexation
Greater Gabbard	32.1	33.2	37.0	38.8	40.2	Current revenues plus indexation
London Array	44.7	46.8	52.6	57.3	58.9	Current revenues plus indexation
Thanet	20.8	21.6	24.0	26.3	27.3	Current revenues plus indexation
Lincs	30.0	32.5	34.0	40.9	40.0	Current revenues plus indexation
Gwynt y mor	32.9	39.8	37.6	37.4	57.8	Current revenues plus indexation and IAE
West of Duddon Sands	25.3	25.5	28.5	30.3	32.2	Current revenues plus indexation
Humber Gateway	14.4	13.3	15.0	16.6	17.0	Current revenues plus indexation
Westermost Rough	14.1	14.7	16.5	18.0	18.6	Current revenues plus indexation
Burbo Bank Extension	14.1	14.7	16.4	17.7	18.4	Current revenues plus indexation
Dudgeon	19.6	20.8	22.6	24.9	26.1	Current revenues plus indexation
Race Bank	27.4	28.9	32.5	35.4	31.6	Current revenues plus indexation
Galloper	17.1	17.8	20.1	21.9	22.5	Current revenues plus indexation
Walney 3	13.5	14.1	15.9	17.3	17.7	Current revenues plus indexation
Walney 4	13.5	14.1	15.9	17.3	17.7	Current revenues plus indexation
Hornsea 1A	137.1	18.4	20.6	22.2	20.2	Current revenues plus indexation
Hornsea 1B		18.4	20.6	22.2	20.2	Current revenues plus indexation
Hornsea 1C		18.4	20.6	22.2	20.2	Current revenues plus indexation
Beatrice		21.1	24.4	25.7	26.4	Current revenues plus indexation
Rampion		15.5	17.4	19.7	20.3	Current revenues plus indexation
East Anglia 1		68.3	47.4	51.8	54.7	Current revenues plus indexation
Hornsea 2A			138.7	25.3	26.5	Current revenues plus indexation
Hornsea 2B				25.3	26.5	Current revenues plus indexation
Hornsea 2C				25.3	26.5	Current revenues plus indexation
Triton Knoll				41.3	44.0	Current revenues plus indexation
Moray East				28.2	50.3	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2024/25				52.6	90.5	NESO Forecast
Forecast to asset transfer to OFTO in 2025/26					30.4	NESO Forecast
Offshore Transmission Pass-Through	**549.0**	**594.3**	**765.6**	**879.8**	**1,005.6**	

Notes:

Figures for historic years represent NESO's forecast of OFTO revenues at the time final tariffs were calculated for each charging year rather than our current best view. It is possible that anticipated asset transfer dates moved between charging years in which case where a previous year shows a forecast for multiple sites, other sites may also have been included in addition to the ones shown.

Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders.

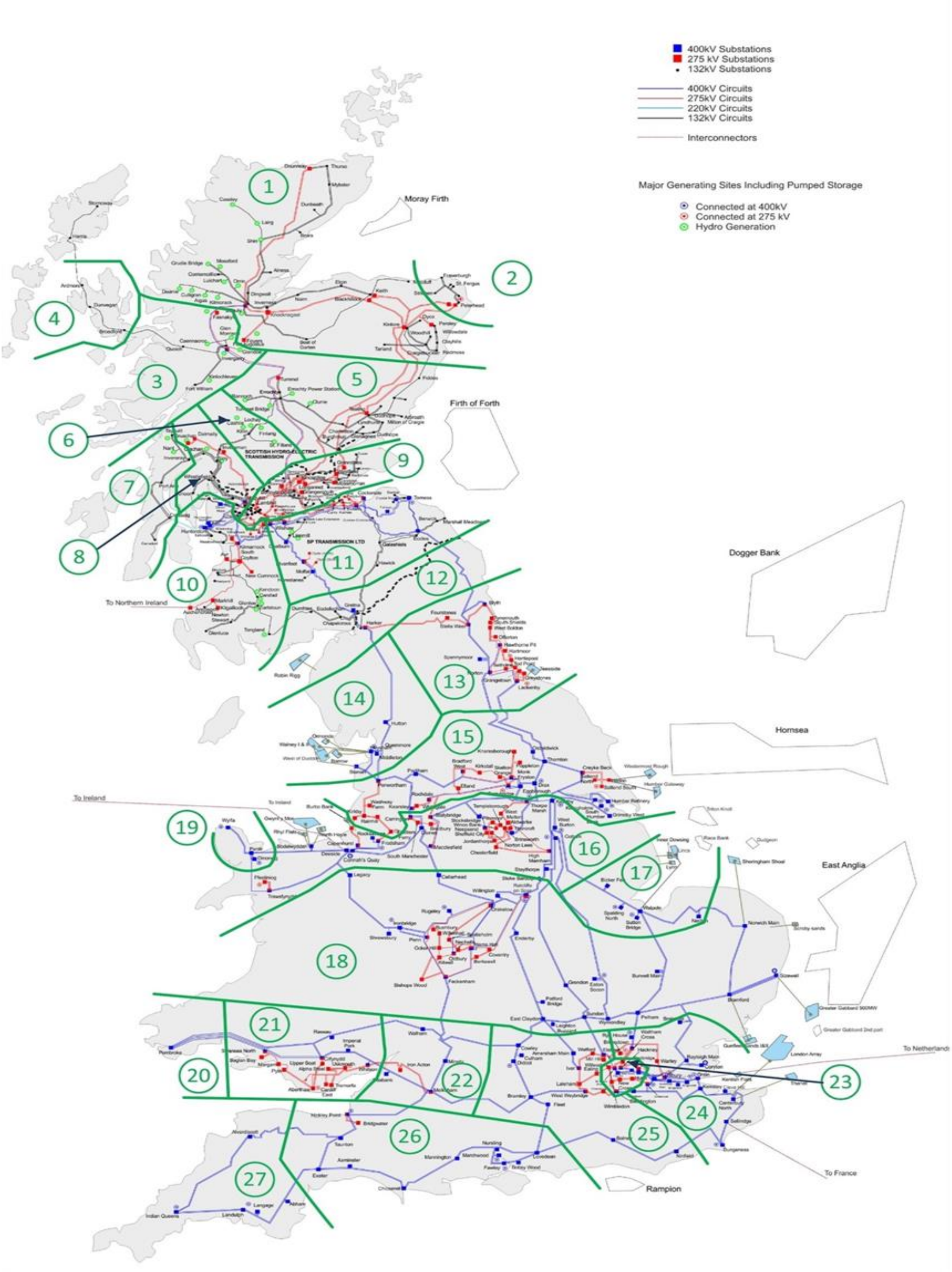
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed.

NIC & SIF payments are not included as they do not form part of OFTO Revenue

IAE = Income Adjusting Event

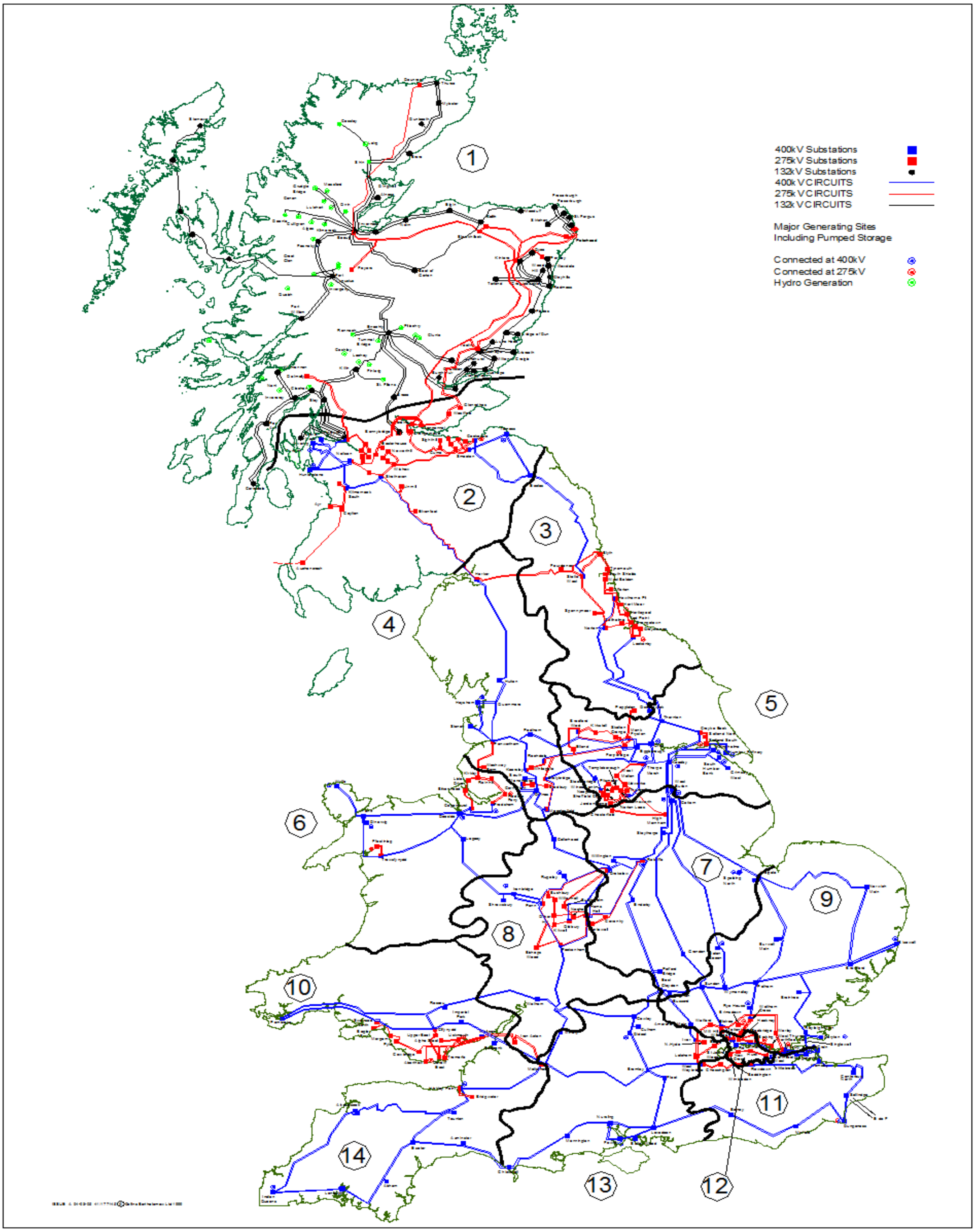
Appendix G: Generation Zones Map

Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to Electricity Ten Year Statement 2023 Appendix A.

Appendix H: Demand Zones Map


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
1
2
3
4
5
6
7
8
9
10
11
12
13
14

Appendix I: Changes to TNUoS parameters

The following table summarises the various inputs to the tariff calculations, indicating which updates are provided in each forecast during the year. Purple highlighting indicates that parameters are fixed from that forecast onwards.

2025/26 TNUoS Tariff Forecast					
		April 2024	July 2024	Draft Tariffs November 2024	Final Tariffs January 2025
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	Week 24 Finalised
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	Inflation	Forecast			Actual
RESIDUAL / ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	From OFTOs & NESO best view
	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
	Demand Charging Bases (including TDR site counts)	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
	Consumption Data (by TDR charging band)	Previous year's data source		DNO/IDNO consumption update received	
	Generation Charging Base	NESO best view	NESO best view	NESO best view	NESO final best view
	Generation ALFs	Previous year's data source		Draft ALFs published	Final ALFs published
	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Document Revision History

Document Revision History

Version Number	Date of Issue	Notes
1.0	29 November 2024	Publication of Draft Forecast of 2025/26 TNUoS Tariffs

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