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Initial Forecast of TNUoS Tariffs for 2026/27

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 Initial forecast of TNUoS Tariffs for 2026/27.

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 2026/27 on our website[1].

These tariffs will take effect from 1 April 2026, they have no impact on charging year 2025/26.

Total revenues to be recovered

The total TNUoS revenue to be collected for 2026/27 is forecast to be £6.2bn (an increase of £1.2bn from the 2025/26 Final Tariffs). The increase is mainly due to the latest view of allowed revenue from the Onshore Transmission Owners (ONTOs) for 2026/27 with a combined increase of £928.0m compared to 2025/26. In addition, Offshore Transmission Owners (OFTOs) and Interconnector contributions have seen an aggregated increase of £108.6m, and other items an increase of £116.1m. The 2026/27 revenue forecast will be updated through the year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions and other relevant information.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.27bn for 2026/27, an increase of £141.4m since 2025/26. This is mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base has been updated to 110.0 GW based on our best view on generation projects for 2026/27, this view will be further refined throughout the year. The average generation tariff is forecast to be £11.55/kW, a decrease of £1.17/kW due to the increase in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £4.97bn for 2026/27, a £1.01bn increase compared to 2025/26 Final Tariffs. The increase in demand revenue is the result of the increase in TNUoS revenue.

The TNUoS cost for the average domestic household is forecast to be £64.03 for 2026/27 which forms 6.9% of the average annual electricity consumer bill, an increase in the proportion of the consumer bill from 5.8% in 2025/26.

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

In 2026/27, it is forecast that £22.73m would be payable to embedded generators (<100 MW) through the Embedded Export Tariff (EET), a decrease of £0.15m compared to the forecast for 2025/26. This is due to forecast export volume over the Triad decreasing. The average EET is forecast to be £3.32/kW, which is an increase of £0.24/kW from 2025/26.

The average gross HH demand tariff for 2026/27 is £9.48/kW, an increase of £0.99/kW compared to 2025/26 and the average NHH demand tariff forecast is forecast to be 0.45p/kWh, an increase of 0.06p/kWh from 2025/26

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2026/27 is available on our website[2].

Our next TNUoS tariff publication will be our Five-Year View of 2026/27 – 2030/31 tariffs, which will be published in August 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.

Our contact details:

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TNUoS.Queries@nationalenergyso.com

[2] neso.energy/document/353071/download

Charging Methodology Changes

This Report

This report contains the initial forecast of TNUoS tariffs for the charging year 2026/27.

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

No changes have been approved to the charging methodology since we published the Final Tariffs for 2025/26 and consequently no additional changes have been incorporated in this forecast.

There are 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 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].

Please note that this ongoing work has not been included in this forecast and details of any CUSC modifications that may impact 2026/27 tariffs can be found in Appendix B.

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

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

Changes due to the new Price Control period

In accordance with the CUSC, several parameters which affect the locational and non-locational elements of the tariff must be recalculated and reset in preparation for the new price control, to apply from 1 April 2026.

Input data for the recalculation of parameters is required from a number of sources, including the onshore TO's and the Ofgem RIIO-ET3 determinations, and will become available at different stages over the course of this year. It is anticipated that we will include indicative parameters, based on the information available later this year, in the Five-Year View.

The key components which need to be addressed at the price control, and how they are treated in this forecast, are outlined in the following table.

Component	Description	Assumptions for 2026/27 onwards
Maximum Allowed Revenue	The MAR for onshore TOs in the new price control period will be determined during the negotiations up to the start of the price control period.	**Our assumption in this forecast is based on current Onshore TOs' MAR forecast under relevant STC procedures.**
Generation zones	There are currently 27 generation zones. The recalculation of zones used to be linked to price control but is currently fixed, pending the outcome of a CUSC modification to change the underlying methodology.	**Our assumption in this forecast is that the number of generation zones remains at 27, pending the outcome of "CMP419: Generation Zoning Methodology Review".**

Component	Description	Assumptions for 2026/27 onwards
Expansion Constant and Factors	The Expansion Constant represents the cost of moving 1MW, 1km using 400kV OHL line. The Expansion Factors represent how many times more expensive moving 1MW, 1km is using different voltages and types of circuit. The Expansion Constant and Expansion Factors are currently fixed at those that were used in 2020/21, with the Expansion Constant subject to annual inflation by CPIH, pending the outcome of a CUSC modification to change the underlying methodology.	**Our assumption in this forecast is that the Expansion Constant continues to increase by CPIH as per the CUSC, and that the expansion factors are unchanged; pending the outcome of "CMP315/375: Expansion Constant & Expansion Factor Review"**
Locational Onshore Security Factor	The security factor is currently 1.76. This will be recalculated by the start of RIIO-ET3 period. It is also the subject of "CMP432: Improve "Locational Onshore Security Factor" for TNUoS Wider Tariffs".	**Our assumption in this forecast is the security factor remains as 1.76.**
Onshore Local Substation Tariffs	Local Substation tariffs will be recalculated in preparation for the start of the price control based on TO asset costs.	**Our assumption in this forecast is that Local Substation Tariffs increase by CPIH.**
Offshore Local Tariffs	The elements for the offshore tariffs will be recalculated in preparation for the start of the price control, based on updated forecasts of OFTO revenue, and adjusting for differences in actual OFTO revenue to forecast revenue in RIIO-ET2.	**Our assumption in this forecast is that the Offshore Local Tariffs continue to inflate in line with the revenue of the relevant OFTO.**

Component	Description	Assumptions for 2026/27 onwards
Avoided GSP Infrastructure Credit (AGIC)	The AGIC is a component of the Embedded Export Tariff, paid to 'exporting demand' at the time of Triad. It will be recalculated based on the most recent 20 schemes.	**Our assumption in this forecast is that the AGIC increases by CPIH.**
TDR Banding Thresholds	The thresholds for the TDR charging bands are required to be recalculated by the start of the RIIO-ET3 price control. They are calculated based on the voltage level and percentiles to be applicable during the price control for DUoS and TNUoS.	**In this forecast we have used the updated TDR Banding Thresholds, which have been calculated for RIIO-ET3. Please refer to table TAA in the published tables excel spreadsheet[5] for the new banding thresholds.**

[5] neso.energy/document/359811/download

Generation Tariffs

Generation Wider Tariffs

Onshore Local Substation Tariffs

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Offshore Local Tariffs

Generation Tariffs Summary

This section summarises our view of generation tariffs for 2026/27 and how these tariffs were calculated.

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	2025/26 Final	2026/27 April	Change since last forecast
Adjustment	- 1.753040	- 1.540870	0.212170
Average Generation Tariff*	12.726944	11.552840	- 1.174104

*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, henceforth known as the "gen cap".

Average generation tariffs have decreased by £1.17/kW, due to the 21.3 GW increase in the generation charging base, compared to 2025/26. The generation adjustment has increased by £0.21/kW, decreasing in magnitude, to become less negative; this is because the expected increase to the charging base means that less of an adjustment 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 2026/27. 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

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Example tariffs for a generator of each technology type: Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	4.392142	25.779423	13.975749	-1.540870	18.753341	36.161588	24.035619
2	East Aberdeenshire	5.626445	17.809393	13.975749	-1.540870	16.799632	31.418369	20.449106
3	Western Highlands	4.498991	24.579009	13.342322	-1.540870	18.126653	34.734700	22.862006
4	Skye and Lochalsh	-3.484814	24.579009	12.957839	-1.540870	9.989055	26.366412	22.477523
5	Eastern Grampian and Tayside	6.368653	20.000320	10.369634	-1.540870	16.975765	30.197657	17.828908
6	Central Grampian	6.123791	19.674145	10.035937	-1.540870	16.466954	29.374467	17.348432
7	Argyll	5.922280	18.004421	16.914425	-1.540870	18.348948	34.799151	23.475544
8	The Trossachs	4.767230	18.004421	8.301745	-1.540870	13.748826	25.031421	14.862864
9	Stirlingshire and Fife	4.103228	17.349994	7.875714	-1.540870	12.652641	23.450568	14.142341
10	South West Scotlands	3.237968	16.722130	7.606211	-1.540870	11.428434	21.844907	13.590300
11	Lothian and Borders	5.145207	16.722130	2.650395	-1.540870	11.353347	18.796330	8.634484
12	Solway and Cheviot	3.035614	10.173765	4.688579	-1.540870	7.439682	13.813647	7.725903
13	North East England	6.080685	6.660296	2.998657	-1.540870	8.403396	12.533694	4.454920
14	North Lancashire and The Lakes	3.164903	6.660296	0.173855	-1.540870	4.357693	6.793110	1.630118
15	South Lancashire, Yorkshire and Humber	6.473171	1.882811	0.216711	-1.540870	5.772110	6.561120	-0.476894
16	North Midlands and North Wales	4.169537	0.428184	-	-1.540870	2.799941	2.949805	-1.348187
17	South Lincolnshire and North Norfolk	0.205715	2.918503	-	-1.540870	-0.167754	0.853722	-0.227544
18	Mid Wales and The Midlands	-0.190301	3.093300	-	-1.540870	-0.493851	0.588804	-0.148885
19	Anglesey and Snowdon	6.306202	0.030825	-	-1.540870	4.777662	4.788451	-1.526999
20	Pembrokeshire	5.288265	-10.270830	-	-1.540870	-0.360937	-3.955728	-6.162744
21	South Wales & Gloucester	1.552782	-10.372873	-	-1.540870	-4.137237	-7.767743	-6.208663
22	Cotswold	-0.191900	4.363205	-14.298422	-1.540870	-5.706857	-12.758788	-13.875850
23	Central London	-4.552929	4.363205	-6.463882	-1.540870	-6.934070	-9.285277	-6.041310
24	Essex and Kent	-3.938978	4.363205	-	-1.540870	-3.734566	-2.207444	0.422572
25	Oxfordshire, Surrey and Sussex	-1.628145	-3.183294	-	-1.540870	-4.442333	-5.556486	-2.973352
26	Somerset and Wessex	-4.815567	-4.673479	-	-1.540870	-8.225829	-9.861546	-3.643936
27	West Devon and Cornwall	-4.971387	-14.032194	-	-1.540870	-12.125135	-17.036403	-7.855357

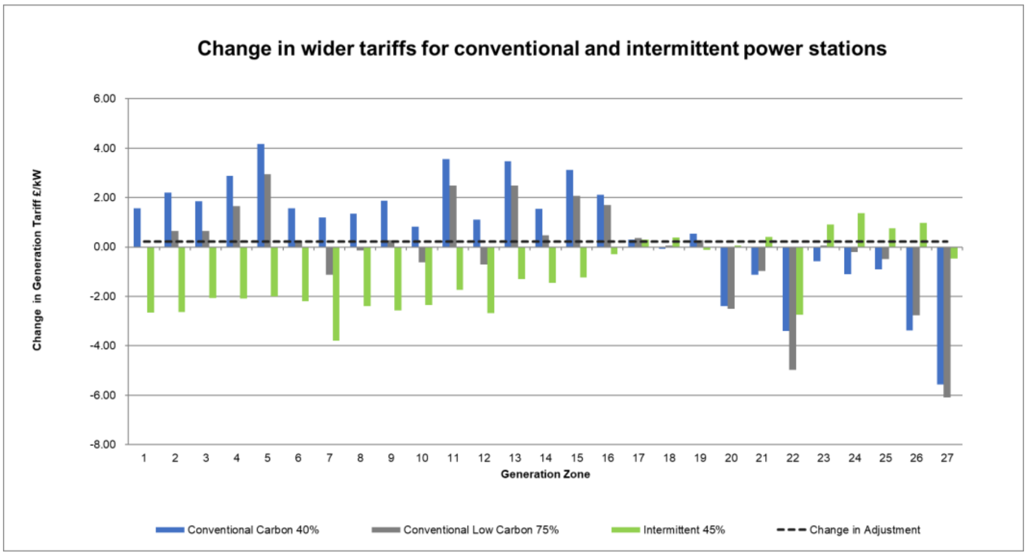
Changes to Wider Tariffs since 2025/26 Final Tariffs

The following section provides details of the wider generation tariffs for 2026/27 and explains how these have changed since 2025/26. 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 Final	2026/27 April	Change	2025/26 Final	2026/27 April	Change	2025/26 Final	2026/27 April	Change	
1	North Scotland	17.192667	18.753341	1.560674	36.182993	36.161588	-0.021405	26.699633	24.035619	-2.664014	0.212170
2	East Aberdeenshire	14.593779	16.799632	2.205853	30.765121	31.418369	0.653247	23.075225	20.449106	-2.626119	0.212170
3	Western Highlands	16.269982	18.126653	1.856671	34.081544	34.734700	0.653156	24.931022	22.862006	-2.069016	0.212170
4	Skye and Lochalsh	7.113679	9.989055	2.875376	24.702371	26.366412	1.664041	24.559573	22.477523	-2.082050	0.212170
5	Eastern Grampian and Tayside	12.804608	16.975765	4.171157	27.249188	30.197657	2.948469	19.821667	17.828908	-1.992759	0.212170
6	Central Grampian	14.907126	16.466954	1.559828	29.164369	29.374467	0.210098	19.536484	17.348432	-2.188052	0.212170
7	Argyll	17.163145	18.348948	1.185803	35.927405	34.799151	-1.128254	27.262031	23.475544	-3.786487	0.212170
8	The Trossachs	12.402074	13.748826	1.346753	25.164277	25.031421	-0.132856	17.258603	14.862864	-2.395739	0.212170
9	Stirlingshire and Fife	10.788639	12.652641	1.864002	23.181275	23.450568	0.269293	16.711138	14.142341	-2.568797	0.212170
10	South West Scotlands	10.608093	11.428434	0.820341	22.466160	21.844907	-0.621253	15.934686	13.590300	-2.344386	0.212170
11	Lothian and Borders	7.802174	11.353347	3.551173	16.318360	18.796330	2.477970	10.364884	8.634484	-1.730400	0.212170
12	Solway and Cheviot	6.342533	7.439682	1.097148	14.531246	13.813647	-0.717599	10.398102	7.725903	-2.672199	0.212170
13	North East England	4.931559	8.403396	3.471837	10.055257	12.533694	2.478437	5.748590	4.454920	-1.293670	0.212170
14	North Lancashire and The Lakes	2.807059	4.357693	1.550634	6.330555	6.793110	0.462555	3.081587	1.630118	-1.451469	0.212170
15	South Lancashire, Yorkshire and Humber	2.659968	5.772110	3.112142	4.482459	6.561120	2.078661	0.754953	-0.476894	-1.231847	0.212170
16	North Midlands and North Wales	0.695856	2.799941	2.104085	1.243931	2.949805	1.705874	-1.047129	-1.348187	-0.301058	0.212170
17	South Lincolnshire and North Norfolk	-0.459885	-0.167754	0.292132	0.496407	0.853722	0.357316	-0.522279	-0.227544	0.294735	0.212170
18	Mid Wales and The Midlands	-0.426819	-0.493851	-0.067032	0.529041	0.588804	0.059764	-0.522835	-0.148885	0.373950	0.212170
19	Anglesey and Snowdon	4.244958	4.777662	0.532704	4.516692	4.788451	0.271759	-1.402425	-1.526999	-0.124574	0.212170
20	Pembrokeshire	2.028195	-0.360937	-2.389132	-1.447282	-3.955728	-2.508445	-6.221511	-6.162744	0.058767	0.212170
21	South Wales & Gloucester	-3.001937	-4.137237	-1.135300	-6.792080	-7.767743	-0.975663	-6.626080	-6.208663	0.417417	0.212170
22	Cotswold	-2.299601	-5.706857	-3.407256	-7.782177	-12.758788	-4.976611	-11.129878	-13.875850	-2.745972	0.212170
23	Central London	-6.353826	-6.934070	-0.580243	-9.335499	-9.285277	0.050222	-6.961706	-6.041310	0.920396	0.212170
24	Essex and Kent	-2.634479	-3.734566	-1.100087	-2.006550	-2.207444	-0.200894	-0.945704	0.422572	1.368276	0.212170
25	Oxfordshire, Surrey and Sussex	-3.528608	-4.442333	-0.913724	-5.066050	-5.556486	-0.490435	-3.729751	-2.973352	0.756399	0.212170
26	Somerset and Wessex	-4.854435	-8.225829	-3.371393	-7.087142	-9.861546	-2.774405	-4.623662	-3.643936	0.979727	0.212170
27	West Devon and Cornwall	-6.567966	-12.125135	-5.557169	-10.948924	-17.036403	-6.087479	-7.385700	-7.855357	-0.469657	0.212170

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. This has resulted in increases to Conventional Carbon and Conventional Low Carbon tariffs in the North and decreases in the South; meanwhile Intermittent tariffs are expected to see decreases in the North and mostly increases in the South.

Adjustment Tariff Changes

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

The adjustment tariff has increased by £0.21/kW since 2021, decreasing in magnitude, to become less negative. This is because the charging base is expected to increase, meaning that there is less adjustment required across each generator 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.

For this April 2026/27 Initial forecast, we have assumed that the onshore local substation tariffs, which were set prior to the RIIO-ET2 period continue to be inflated in line with CPIH.

Table 4 Onshore Local Substation Tariffs

2026/27 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.185199	0.092604	0.063873
<1320 MW	Redundancy	0.390234	0.198206	0.140738
≥1320 MW	No redundancy	-	0.272067	0.193704
≥1320 MW	Redundancy	-	0.409414	0.294469

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 onshore local circuit tariffs have been updated, and will be further refined in subsequent quarterly forecasts. Table 5 shows the 2026/27 forecast of onshore local circuit tariffs.

Table 5 Onshore Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.766053	Douglas North	0.784912	Langage	-0.416727
Aberdeen Bay	3.453615	Dunhill	1.848568	Limekilns	2.487453
Achruach	-1.686432	Dunlaw Extension	0.550570	Lochay	0.392456
Aigas	0.906839	Dunmaglass	1.121771	Luichart	0.727523
An Suidhe	-1.082225	Edinbane	8.828984	Marchwood	-0.304420
Arecleoch	3.100469	Enoch Hill	0.784912	Mark Hill	1.138188
Arecleoch Extension	2.685340	Ewe Hill	1.796578	Middle Muir	2.723646
Ayrshire Grid Collector	0.174410	Fallago	-0.083608	Middleton	0.182221
Beinneun Wind Farm	1.740311	Farr	4.486521	Millennium Wind	2.056896
Benbrack	0.939715	Fernoch	5.529252	Mossford	2.048024
Bhlaraidh Extension	3.847051	Ffestiniog	0.280449	Nant	-1.604250
Bhlaraidh Wind Farm	0.786003	Fife Grid Services	0.195807	Necton	0.567586
Black Hill	1.980609	Finlarig	0.392456	Pont Abraham	-0.149115
Blackcraig	7.143863	Foyers	0.360578	Rhigos	0.128193
Blacklaw	2.158509	Galawhistle	1.347434	Rocksavage	0.019001
Blacklaw Extension	4.695322	Glen Kyllachy	1.286614	Saltend	-0.019994
Broken Cross	1.372240	Glen Ullinish windfarm	8.885127	Sandy Knowe	5.427053
Chirmorie	2.781383	Glendoe	2.573228	Sanquhar II	8.925568
Clyde (North)	0.136583	Glenglass	5.906314	Shepherds Rig	0.093300
Clyde (South)	0.159346	Gordonbush	-0.006400	South Humber Bank	-0.229639
Coalburn BESS	0.484471	Griffin Wind	12.538960	Spalding	0.350988
Corriegarth	3.139650	Hadyard Hill	3.532106	St Fergus Mobil	1.315629
Corriemoillie	2.048024	Harestanes	2.943422	Stranoch	3.880260
Coryton	0.053040	Hartlepool	0.470777	Strathbrora	-0.136829
Creag Riabhach	4.317018	Heathland	3.769038	Strathy Wind	2.168221
Cruachan	2.284879	Hopsrig collector	2.973947	Strathy Wood	4.312577
Culligran	2.230515	Invergarry	0.392456	Stronelairg	1.382674
Cumberhead Collector	0.898289	Kergord	63.098060	Tangy IV	0.112286
Cumberhead West	4.760471	Kilgallioch	1.365825	Wester Dod	0.449145
Deanie	3.664417	Kilmarnock BESS	0.503850	Whitelee	0.136583
Dersalloch	2.892854	Kilmorack	0.159322	Whitelee Extension	0.386984
Dinorwig	3.226638	Kype Muir	1.908864		
Dorenell	3.096352	Lairg South	1.060957		

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

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 January, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs associated with projects due to transfer in 2025/26 or 2026/27 will be confirmed once asset transfer has taken place and tariffs have been set.

Table 7 Offshore local tariffs 2026/27

Offshore Generator	2025/26 Final Tariff Component (£/kW)			2026/27 April Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.656304	61.579655	1.529107	12.002538	63.408787	1.574527	0.346234	1.829132	0.045420
Beatrice	9.389647	25.744817	-	9.677140	26.533076	-	0.287493	0.788259	-
Burbo Bank Extension	14.584257	28.186900	-	15.030800	29.049930	-	0.446543	0.863030	-
Dudgeon	21.331780	33.469891	-	21.984920	34.494676	-	0.653140	1.024785	-
East Anglia 1	12.627454	53.291208	-	13.014083	54.922885	-	0.386629	1.631677	-
Galloper	21.835962	34.535819	-	22.504538	35.593242	-	0.668576	1.057423	-
Greater Gabbard	21.715879	50.252729	-	22.360917	51.745411	-	0.645038	1.492682	-
Gunfleet Sands I	25.366596	23.392552	4.372202	26.120073	24.087393	4.502072	0.753477	0.694841	0.129870
Gunfleet Sands II	25.366596	23.392552	4.372202	26.120073	24.087393	4.502072	0.753477	0.694841	0.129870
Gwynt y mor	27.387460	27.077491	-	28.226013	27.906553	-	0.838553	0.829062	-
Hornsea 1A	9.747932	34.489707	-	10.046396	35.545717	-	0.298464	1.056010	-
Hornsea 1B	9.747932	34.489707	-	10.046396	35.545717	-	0.298464	1.056010	-
Hornsea 1C	9.747932	34.489707	-	10.046396	35.545717	-	0.298464	1.056010	-
Hornsea 2A	11.047354	37.319614	-	11.384453	38.458385	-	0.337099	1.138771	-
Hornsea 2B	11.047354	37.319614	-	11.384453	38.458385	-	0.337099	1.138771	-
Hornsea 2C	11.047354	37.319614	-	11.384453	38.458385	-	0.337099	1.138771	-
Humber Gateway	16.117673	36.979486	-	16.611166	38.111729	-	0.493493	1.132243	-
Lincs	22.375180	87.993930	-	23.060266	90.688140	-	0.685086	2.694210	-
London Array	15.184275	52.061059	-	15.649189	53.655071	-	0.464914	1.594012	-
Moray East	11.318789	28.352051	-	11.665350	29.220137	-	0.346561	0.868086	-
Ormonde	35.838076	66.989132	0.533847	36.902592	68.978945	0.549704	1.064516	1.989813	0.015857
Race Bank	12.917939	35.879051	-	13.313463	36.977601	-	0.395524	1.098550	-
Rampion	10.552712	27.605447	-	10.875817	28.450674	-	0.323105	0.845227	-
Robin Rigg	-0.7866000	44.649066	14.305277	-0.8099650	45.975300	14.730194	-0.023365	1.326234	0.424917
Robin Rigg West	-0.7866000	44.649066	14.305277	-0.8099650	45.975300	14.730194	-0.023365	1.326234	0.424917
Sheringham Shoal	33.529303	39.489373	0.858383	34.525242	40.662346	0.883880	0.995939	1.172973	0.025497
Thanet	25.603836	47.968845	1.154779	26.364360	49.393688	1.189080	0.760524	1.424843	0.034301
Triton Knoll	10.636370	31.688721	-	10.962036	32.658970	-	0.325666	0.970249	-
Walney 1	30.953266	61.883448	-	31.872687	63.721604	-	0.919421	1.838156	-
Walney 2	28.797474	58.605728	-	29.652860	60.346524	-	0.855386	1.740796	-
Walney 3	13.269379	26.882966	-	13.675663	27.706073	-	0.406284	0.823107	-
Walney 4	13.269379	26.882966	-	13.675663	27.706073	-	0.406284	0.823107	-
West of Duddon Sands	11.867124	59.156062	-	12.230474	60.967310	-	0.363350	1.811248	-
Westermost Rough	24.129810	41.065869	-	24.868620	42.323230	-	0.738810	1.257361	-

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 standing charges make up majority of the TNUoS demand charge in the form of a non-locational set of daily charges per site across of the residual charging bands.

Table 8 Summary of Demand Tariffs

Non-locational Banded Tariffs	2025/26 Final	2026/27 April	Change
Average (£/site/annum)	118.39	148.45	30.06
Unmetered (p/kWh/annum)	1.571791	1.980257	0.408466
Demand Residual (£m)	3,836.05	4,832.93	996.88
HH Tariffs (Locational)	**2025/26 Final**	**2026/27 April**	**Change**
Average Tariff (£/kW)	8.485606	9.479254	0.993648
EET	**2025/26 Final**	**2026/27 April**	**Change**
Average Tariff (£/kW)	3.084154	3.320853	0.236699
AGIC (£/kW)	2.791637	2.879894	0.088257
Embedded Export Volume (GW)	7.417380	6.844238	- 0.573142
Total Credit (£m)	22.88	22.73	- 0.15
NHH Tariffs (locational)	**2025/26 Final**	**2026/27 April**	**Change**
Average (p/kWh)	0.383426	0.448022	0.064596

Compared to 2025/26, both the average HH & NHH demand tariffs have seen an increase. Driven by increases in demand zone 14 due to decreased contracted TEC in the South West. Revenue to be recovered through the demand residual is forecast to be £997m higher than 2025/26 which, with an additional locational revenue of £14m gives a total Demand revenue increase compared to 2025/26 of £1.01bn

The average HH gross tariff is forecast to be £9.48/kW, an increase of £0.99/kW compared to 2025/26 Final Tariffs. The average NHH tariff is forecast to be 0.45 p/kWh, an increase of 0.06 p/kWh from the current year.

The forecast Embedded Export Volume for 2026/27 has decreased compared to 2025/26 by 0.57 GW to 6.84 GW. The total credit paid out to embedded generators (<100 MW) is currently forecast to be £22.73m, a decrease of just £0.15m. The average Embedded Export Tariff (EET) is now forecast to be £3.32/kW, an increase of £0.24/kW compared to the 2025/26 Final Tariffs.

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	-	-	-
7	East Midlands	-	-	2.036350
8	Midlands	3.119104	0.421146	5.998998
9	Eastern	0.637046	0.091692	3.516940
10	South Wales	7.959162	0.975986	10.839056
11	South East	5.625208	0.811494	8.505102
12	London	6.993935	0.754048	9.873829
13	Southern	8.382088	1.138618	11.261982
14	South Western	15.566653	2.257036	18.446547

Demand Residual Tariffs

The Site count forecast has been updated to reflect the re-banding of all sites using the new residual charging band thresholds for the start of RIIO-ET3.

The consumption data used to allocate the proportion of residual revenue to each charging band has not changed and continues to use actual data for October 2023 to September 2024, received from the DNOs.

A breakdown of the banding thresholds, consumptions, consumption proportions and site counts for the demand residual standing charges can be seen in Table TB of the published tables excel spreadsheet[6]. The residual band thresholds will remain the same for the duration of the RIIO-ET3 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.

[6] 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 Final	2026/27 April	Change
Domestic	Tariff - £/Site/Day	0.135043	0.169156	0.034113
LV_NoMIC_1		0.154829	0.194529	0.039700
LV_NoMIC_2		0.366046	0.457684	0.091638
LV_NoMIC_3		0.760709	0.993546	0.232837
LV_NoMIC_4		2.068587	2.740169	0.671582
LV1		3.907710	4.560845	0.653135
LV2		6.529117	9.032638	2.503521
LV3		10.251874	11.293090	1.041216
LV4		22.739548	30.237006	7.497458
HV1		21.830361	24.378378	2.548017
HV2		62.799637	91.022117	28.222480
HV3		121.795409	144.945698	23.150289
HV4		317.597969	414.802106	97.204137
EHV1		160.765059	239.902567	79.137508
EHV2		741.786430	863.303060	121.516630
EHV3		1,576.232814	1,793.623154	217.390340
EHV4		3,882.736230	4,085.027223	202.290993
T-Demand1		647.798551	870.553009	222.754458
T-Demand2		2,287.643779	2,470.404867	182.761088
T-Demand3		5,446.380603	6,432.885014	986.504411
T-Demand4		12,796.715359	16,122.227113	3,325.511754
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		1.571791	1.980257	0.408466
Demand Residual (£m)		**3836.05**	**4832.93**	**996.88**

On average, Transmission Demand Residual tariffs have increased by 26% compared to 2025/26 Final Tariffs, driven by the increase in revenue to be collected.

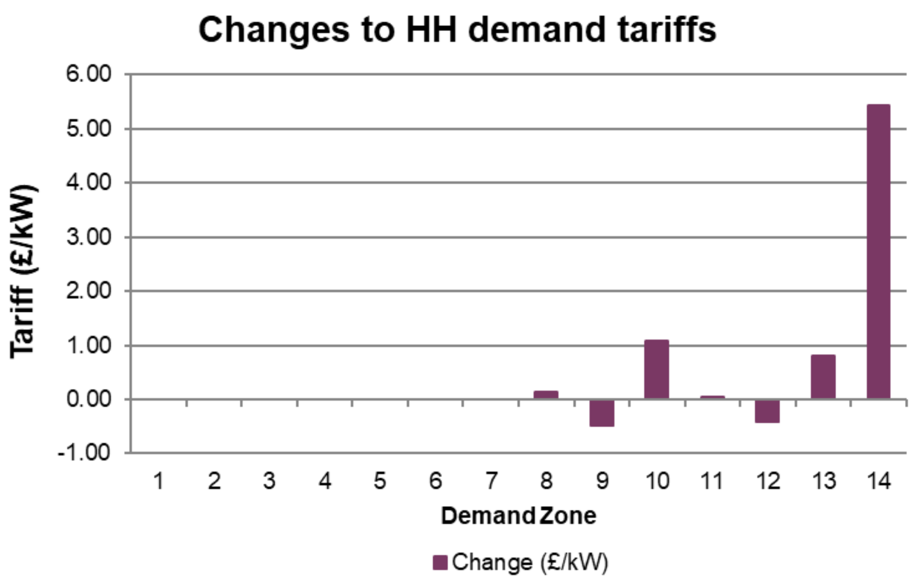
Half-Hourly Demand Tariffs

Table 11 shows the forecast gross HH demand tariffs for 2026/27 compared to 25/26 Final Tariffs.

Table 11 Half-Hourly Demand Tariffs

Zone	Zone Name	2025/26 Final (£/kW)	2026/27 April (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	-
8	Midlands	2.990958	3.119104	0.128146
9	Eastern	1.110745	0.637046	-0.4736990
10	South Wales	6.885043	7.959162	1.074119
11	South East	5.568235	5.625208	0.056973
12	London	7.405345	6.993935	-0.4114100
13	Southern	7.570174	8.382088	0.811914
14	South Western	10.123037	15.566653	5.443616

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, there are fluctuations in tariffs for zones 8 through to 14. These are due to changes in Nodal demand and generation forecasts. The largest impact is seen in zone 14 driven by decreases in the contracted TEC in the Sout West. Zones 1 through 7 are subject to the zero floor on demand tariffs.

The forecast level of gross HH chargeable demand has decreased by 0.28 GW since from 2025/26 and is currently forecast to be 16.67 GW.

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 2026/27.

Table 12 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		3.463760	8.510611	11.974371
BARK	BARKING	9	12		3.603606	0.211885	3.815491
WISD	WILLESDEN	9	12	13	3.511567	1.826122	5.337690

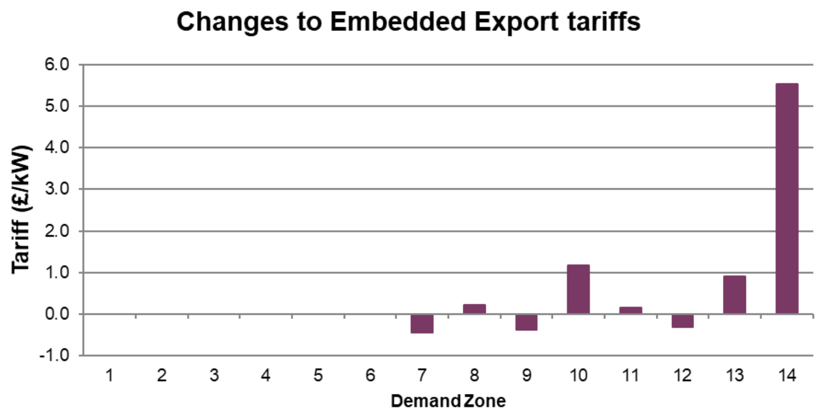
Embedded Export Tariffs (EET)

Table 13 shows the forecast Embedded Export tariffs for 2026/27 compared to the 2025/26 Final Tariffs.

Table 13 Embedded Export Tariffs

Zone	Zone Name	2025/26 Final (£/kW)	2026/27 April (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	2.483002	2.036350	-0.4466520
8	Midlands	5.782595	5.998998	0.216403
9	Eastern	3.902382	3.516940	-0.3854420
10	South Wales	9.676680	10.839056	1.162376
11	South East	8.359872	8.505102	0.145230
12	London	10.196982	9.873829	-0.3231530
13	Southern	10.361811	11.261982	0.900171
14	South Western	12.914674	18.446547	5.531873

Figure 3 Embedded export tariff changes



The forecast average EET is £3.32/kW an increase to the average EET of £0.24/kW versus the 2025/26 Final Tariff. This is primarily due to a change modelled network flows driven by nodal data. The changes in locational demand tariffs and the corresponding impact can be seen in Table 26. The Embedded Export Volume is forecast to decrease to 6.84 GW.

The amount of metered embedded generation produced at Triads by suppliers and embedded generators (<100 MW) 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.

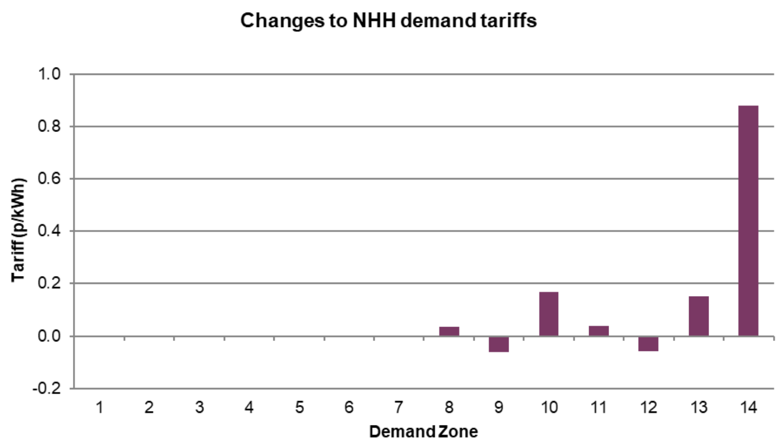
Non-Half-Hourly Demand Tariffs

Table 14 and Figure 4 show the forecast changes in Non-Half-Hourly tariffs between the 2025/26 Final Tariffs and the 2026/27 initial forecast.

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2025/26 Final (p/kWh)	2026/27 April (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	-	-	-
8	Midlands	0.386732	0.421146	0.034414
9	Eastern	0.152494	0.091692	-0.0608020
10	South Wales	0.807732	0.975986	0.168254
11	South East	0.774324	0.811494	0.037170
12	London	0.813457	0.754048	-0.0594090
13	Southern	0.986192	1.138618	0.152426
14	South Western	1.377268	2.257036	0.879768

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2026/27 is 0.45 p/kWh, a 0.06 p/kWh increase compared to the 2505/26 Final Tariffs. As mentioned above for the HH and Embedded tariffs, the locational demand and generation forecasts have caused fluctuations in the NHH zonal tariffs.

Overview of Data Inputs

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

Inputs affecting the locational element of tariffs

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

- Expected Contracted generation (until October 2024 when it will be based on contracted TEC);
- 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 2026/27 period, which can be found on the TEC register[7]. The contracted TEC volumes are based on the 10 March 2025 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 August forecasts, we forecast our best view of modelled TEC. However, for our November Draft Tariffs and January Final Tariffs we will use the contracted TEC position as published in the TEC register as of 31 October 2025, 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 2026/27 and liable to pay generation TNUoS charges.

Table 15 Contracted, Modelled & Chargeable TEC

	2025/26	2026/27 Tariffs			
Generation (GW)	Final	Initial	August	Draft	Final
Contracted TEC	112.2	127.6			
Modelled Best View TEC	*For input to locational tariffs post 31st October please see Contracted TEC*	123.7		*For input to locational tariffs post 31st October please see Contracted TEC*	
Chargeable TEC	88.7	110.0			

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 Round model. Since interconnectors are not liable for generation or demand TNUoS

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

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 2026/27 as stated in the interconnector register[8] as of 10 March 2025.

Table 16 Interconnectors

Interconnector	Node	Interconnected System	Generation MW			
			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
NeuConnect	Grain West 400kV Substation	Germany	24	0	1,400	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 2026/27 Expansion Constant is forecast to be £18.993795/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-ET1 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-ET2, 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.

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

As the necessary network studies have not yet been undertaken for RIIO-ET3 it is currently forecast to remain at 1.76.

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-ET2, 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-ET2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-ET1 tariff setting.

For this publication, offshore local tariffs are based on the values set for RIIO-ET2 (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-ET3 period spans across 2026/27 – 2030/31). It is important to note that the financial parameters and mechanics for the RIIO-ET3 period are subject to change between now and final determination in Q4 2025.

Onshore TOs allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process (AIP).

The TOs provide NESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The 2026/27 revenue forecast has been based on Onshore and Offshore TOs' submissions in January 2025. The 2026/27 revenue forecast will be updated and finalised based on Onshore and Offshore TOs' submissions throughout the year.

An overview of revenue to be recovered can be found in Table 17. For this publication, we have included a five-year view of allowed revenues, based on the TO submissions in

January 2025. These values are highly indicative and subject to change, as final determinations for RIIO-ET3 are not expected until Q4 2025.

Table 17 Allowed Revenues

£m Nominal	2026/27	2027/28	2028/29	2029/30	2030/31
ONTO Income from TNUoS					
National Grid Electricity Transmission	2,590.0	2,641.8	2,694.7	2,748.6	2,803.5
Scottish Power Transmission	899.2	1,069.2	1,301.8	1,534.7	1,708.3
SHE Transmission	1,573.0	2,058.7	2,510.3	2,730.4	2,815.8
Total ONTO Income from TNUoS	**5,062.2**	**5,769.7**	**6,506.7**	**7,013.6**	**7,327.6**
Other Income from TNUoS					
Other Pass-through from TNUoS	135.6	90.8	53.8	45.7	45.7
Offshore (plus interconnector contribution / allowance)	1,041.8	1,186.2	1,291.0	1,360.1	1,432.0
Total Other Income from TNUoS	**1,177.4**	**1,277.0**	**1,344.8**	**1,405.8**	**1,477.7**
Total to Collect from TNUoS	**6,239.6**	**7,046.7**	**7,851.5**	**8,419.4**	**8,805.3**

Please note these figures are rounded to one decimal place.

Onshore TO revenue assumptions for the RIIO-ET3 are dependent on the Transmission Owner. Forecasts for National Grid Electricity Transmission are based on the 2025/26 allowed revenue adjusted for long term inflation. Forecasts for Scottish Power Transmission and SSEN Transmission (SHET) are based on recent Business Plan submissions for RIIO-ET3, and the available data at the time that these forecasts were submitted. Inflation has been applied at 2% for the RIIO-ET3 period.

For more details on the TNUoS revenue breakdown for 2026/27, please refer to Appendix F: Transmission Company Revenues.

For sensitivity analysis on the impact of additional revenue on the Transmission Demand Residual (TDR), please refer to Appendix F: Sensitivity Analysis

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 £8m) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is an increase of £0.9m to local charges associated with pre-existing assets since 2025/26 Final Tariff publication

Table 18 Generation and demand revenue proportions

		2026/27 Tariffs			
Code	**Revenue**	**Initial**	**August**	**Draft**	**Final**
CAPEC	Limit on generation tariff (€/MWh)	2.50			
y	Error Margin	29.6%			
ER	Exchange Rate (€/£)	1.19			
MAR	Total Revenue (£m)	6,238.9			
GO	Generation Output (TWh)	232.1			
G	% of revenue from generation	20.37%			
D	% of revenue from demand	79.63%			
G.R	Revenue recovered from generation (£m)	1,270.7			
D.R	Revenue recovered from demand (£m)	4,968.2			
Breakdown of generation revenue					
	Revenue from the Peak element	170.7			
	Revenue from the Year Round Shared element	191.8			
	Revenue from the Year Round Not Shared element	141.6			
	Revenue from Onshore Local Circuit tariffs	50.9			
	Revenue from Onshore Local Substation tariffs	17.6			
	Revenue from Offshore Local tariffs	867.6			
	Revenue from the adjustment element	-169.5			
G.MAR	Total Revenue recovered from generation (£m)	1,270.7			
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	8.0			

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. In this report, the figures were based on OBR’s March EFO. This figure is indicative, as per OBR’s March EFO, at €1.192525/£.

Generation Output

The forecast output of generation is 232 TWh. This figure is the average of the four scenarios (plus the central case) in the 2024 Future Energy Scenarios. For 2026/27 tariffs, this figure will be updated in the next quarterly forecast, to be published by August.

Error Margin

The error margin for 2026/27 tariffs will be updated and finalised in the next quarterly forecast, following publication of the outturn of 2024/25 data. In this report, the error margin is the same as we used for 2025/26 Final tariffs, derived from historical data in the past five whole years (thus for year 2025/26, we used 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 two sets of tariffs relating to pre-existing assets. These are TNUoS local tariffs associated with pre-existing circuits and those for pre-existing substation bays. For the 2026/27 tariff year at the draft and final publications we will also include 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; it 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)
Aberarder Wind Farm	0.784912	Glen App Windfarm	0.000000
Aberdeen Offshore Wind Farm	0.000000	Glen Kyllachy Wind Farm	0.000000
A'Chruach Wind Farm	0.000000	Glenmuckloch Wind Farm	1.980609
Afton Wind Farm	0.000000	Hareshaw Rig Wind Farm	0.000000
Aikengall II Windfarm	0.000000	Harting Rig Wind Farm	0.000000
Aikengall IIa Wind Farm	0.000000	Hartlepool	0.000000
Alcemi Coalburn Battery Energy Storage Facility	0.000000	Hopsrig Wind Farm	0.000000
Arecleoch Windfarm Extension	2.194769	Hunterston Energy Storage Facility	0.000000
Beinneun Wind Farm	0.060980	Kennoxhead Wind Farm	2.723646
Benbrack wind farm	0.449145	Kennoxhead Wind Farm Extension	2.723646
Bhlaraidh Wind Farm	0.000000	Kilmarnock BESS	0.000000
Blacklaw	0.000000	Kincardine Battery Storage Facility	0.000000
Blacklaw Extension	0.000000	Kype Muir	0.000000
Broken Cross Windfarm	0.000000	Lairg II Wind Farm	0.000000
Builth Wells	0.000000	Limekiln	0.000000
Carraig Gheal Wind Farm	5.529047	Lochluichart	0.000000
Chirmorie Wind Farm	2.722514	Loganhead Windfarm	0.000000
Clyde North	0.000000	Marchwood	0.000000
Clyde South	0.000000	Middle Muir Wind Farm	0.000000
Corriegarth	0.000000	Pen Y Cymoedd Wind Farm	0.000000
Coryton ENERGY	0.000000	Pencloe Windfarm	0.000000
Crossdykes	0.000000	Rocksavage	0.000000
Cruachan	0.000000	Saltend	0.000000
Cumberhead	0.000000	Sandy Knowe Wind Farm	0.000000
Cumberhead West Wind Farm	0.000000	Sanquhar II Wind Farm	5.906314
Dalquhandy Wind Farm	0.000000	Sanquhar Wind Farm	0.924284
Dersalloch Wind Farm	0.000000	Shepherds Rig Wind Farm	-0.104891
Dinorwig	0.000000	Spalding	0.000000
Dorenell Windfarm	0.000000	Stranoch Wind Farm	2.722514
Douglas West	0.784912	Strathy Wood	0.000000
Douglas West Extension	0.000000	Stronelairg	0.259813
Edinbane Windfarm	0.000000	Twentyshilling Wind Farm	0.000000
Enoch Hill	0.000000	Viking Wind Farm	0.000000
Ewe Hill	0.000000	Whitelee Extension	0.000000
Fallago Rig Wind Farm	0.000000	Whiteside Hill Wind Farm	0.000000
Ffestiniog	0.000000	Windy Rig Wind Farm	0.000000
Foyers	0.000000	Windy Standard II (Brockloch Rig) Wind Farm	0.000000
Galawhistle Wind Farm	0.000000	Windy Standard III Wind Farm	0.000000

Aggregated pre-existing TEC (MW)	15,430

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 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	0.185199	37.2
Toddleburn Wind Farm	0.185199	

Charging Bases for 2026/27

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 2026/27 tariffs is forecast at 110.0 GW, which is an increase of 21.3 GW since 2025/26. It is based on our internal view of what generation we expect to connect next financial year.

For the Final Tariffs, in line with the CUSC, we will use the contracted TEC position as of 31 October 2025 to set locational tariffs in the Transport model. Our best view will be 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 2026/27.

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 - March 2025)
- 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. Please refer to table TAA in the published tables excel spreadsheet[9] for a detailed breakdown of the changes to the demand charging bases.

Table 22 Charging Bases

	2026/27 Tariffs			
Charging Bases	**Initial**	**August**	**Draft**	**Final**
Generation (GW)	109.99			
NHH Demand (4pm-7pm TWh)	23.03			
Gross charging				
Total Average Gross Triad (GW)	47.55			
HH Demand Average Gross Triad (GW)	16.67			
Embedded Generation Export (GW)	6.84			

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 final 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[10].

[9] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.
[10] neso.energy/document/352566/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), charges are based on the voltage and size of the site and 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 have been forecast based on the latest trends in site counts being billed and have been adjusted to reflect the new residual banding thresholds and the re-banding for RIIO-ET3 which will take effect from April 2026.

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	2026/27 Tariffs Initial	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	20.37%			
D	Proportion of revenue recovered from demand (%)	79.63%			
R	Total TNUoS revenue (£m)	6,238.9			
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	504.1			
O	Revenue recovered from offshore local tariffs (£m)	867.6			
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.6			
S_G	Revenue recovered from onshore local circuit tariffs (£m)	50.9			
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	8.0			
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.50			
	Error Margin	29.6%			
	Exchange Rate (€/£)	1.19			
	Total generation Output (TWh)	232.10			
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	342.55			
	Adjustment Revenue (£m)	-169.49			
BG	Generator charging base (GW)	109.99			
AdjTariff	Generator adjusment tariff (£/kW)	-1.540870			
Gross demand residual					
R_D	Demand residual (£m)	4,832.9			
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	158.0			
EE	Amount to be paid to Embedded Export Tariffs (£m)	-22.7			
B_D	Demand Gross charging base (GW)	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 publication, 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 Initial forecast of 2026/2027 Tariffs on Thursday 15 May. 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/359811/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**.

Note: Additional Local Tariffs may be applicable to Offshore generators

*** 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.

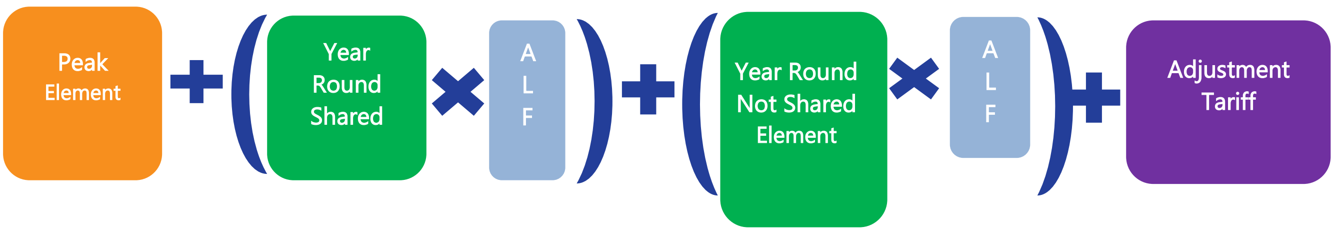
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

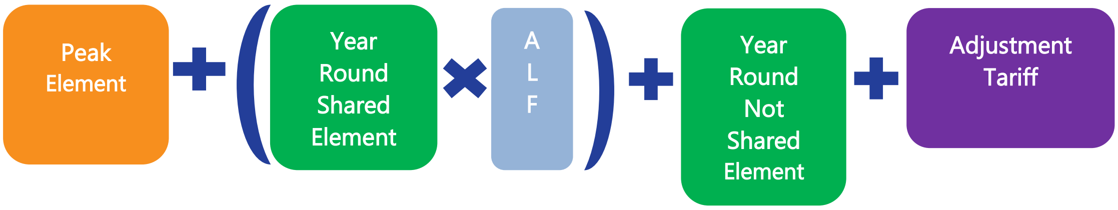
Conventional Carbon Generators

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



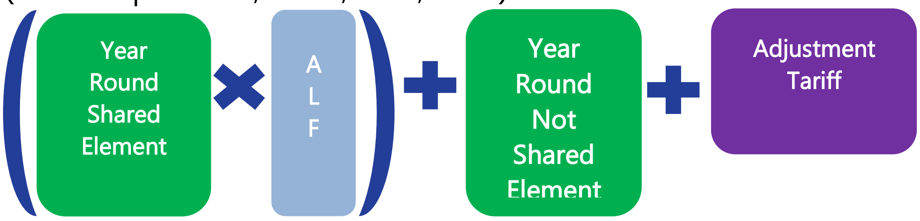
Conventional Low Carbon Generators

(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[11] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[12] 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 100 MW in TEC from 1 April to 31 January, then 350 MW from 1 February to 31 March, the generator will be charged for 350 MW of TEC for that charging year.

The calculation for TNUoS generator monthly invoice is as follows:

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

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

[12] 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[13]. 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[14].

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 (<100 MW CVA registered).

[13] neso.energy/industry-information/charging/tnuos-charges#Triads-data
[14] 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[15].

Embedded generators (<100 MW 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 standing 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.

[15] 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 that could affect the TNUoS tariff calculation methodology for 2026/27. Each modification requires approval from Ofgem, and if any Workgroup Alternative CUSC Modifications (WACMs) are proposed, Ofgem will determine which, if any, are approved.

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 modifications already in progress which could affect 2026/27 tariffs are listed below:

Table 24 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change
CMP315 / CMP375	Expansion Constant & Expansion Factor Review	Affects TNUoS locational tariffs for generators and demand users
CMP316 / CMP397	TNUoS Arrangements for Co-located Generation Sites	Affects TNUoS locational tariffs
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.
CMP405	TNUoS Locational Demand Signals for Storage	Change demand locational tariffs so they are not floored at zero
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

CMP423	Generated Weighted Reference Node	Seeks to change the way the Tariff and Transport model calculates tariffs. There would be no change to the structure of the tariffs, or any other aspect of charging
CMP432	Improve "Locational Onshore Security Factor" for TNUoS Wider Tariffs	Seeks to remove the existing Locational Onshore Security Factor uplift from all TNUoS Wider locational tariffs for both Peak Security and Year-Round, for both generation and demand tariffs. Note it is the intent that local charges would remain unchanged.
CMP440	Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor	Seeks to reintroduce negative locational tariffs for demand
CMP442	Introducing the option to fix Generator TNUoS charges	Seeks to give Generators the opportunity to fix their wider TNUoS charges against the forecast tariffs provided by NESO.
CMP444	Introducing a cap and floor to wider generation TNUoS charges	Seeks to introduce a temporary cap and floor mechanism to wider generation TNUoS charges, to reduce investment uncertainty for generators and developers.
CMP450	Introducing the definition of Dynamic Reactive Compensation Equipment (DRCE) in the CUSC	Seeks to introduce the definition of DRCE in CUSC Section 11, aligning the definition to that included in the Grid Code

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 2026/27

Demand Zone		2025/26 Final		2026/27 April		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	- 0.827604	- 33.839448	-3.173189	-32.168040	- 2.345585	1.671408
2	Southern Scotland	- 1.321113	- 23.621013	-3.753026	-21.739156	- 2.431912	1.881857
3	Northern	- 1.647426	- 11.005420	-5.832979	-8.698161	- 4.185553	2.307259
4	North West	- 0.702065	- 5.877306	-2.869262	-3.829322	- 2.167197	2.047984
5	Yorkshire	- 0.790016	- 4.258236	-4.730148	-1.064221	- 3.940133	3.194015
6	N Wales & Mersey	- 1.884671	- 1.423140	-2.780918	-0.358358	- 0.896247	1.064782
7	East Midlands	- 1.072230	0.763595	-1.985550	1.142006	- 0.913319	0.378410
8	Midlands	- 1.124923	4.115881	-0.987013	4.106118	0.137910	- 0.009763
9	Eastern	0.606933	0.503811	1.988129	-1.3510828	1.381196	- 1.854894
10	South Wales	- 3.661669	10.546712	-2.295374	10.25454	1.366296	- 0.292176
11	South East	2.625117	2.943118	4.697450	0.927758	2.072334	- 2.015360
12	London	3.459054	3.946292	5.219083	1.774852	1.760030	- 2.171440
13	Southern	1.296782	6.273391	3.327490	5.054598	2.030707	- 1.218793
14	South Western	- 0.663438	10.786474	3.60003	11.966623	4.263468	1.180149

Table 26 Elements of the Embedded Export Tariff for 2026/27

Demand Zone		2025/26 Final		2026/27 April		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	- 34.667052	2.791637	-35.341230	2.879894	- 0.674178	0.088257
2	Southern Scotland	- 24.942127	2.791637	-25.492182	2.879894	- 0.550055	0.088257
3	Northern	- 12.652846	2.791637	-14.531140	2.879894	- 1.878294	0.088257
4	North West	- 6.579371	2.791637	-6.698584	2.879894	- 0.119213	0.088257
5	Yorkshire	- 5.048252	2.791637	-5.794370	2.879894	- 0.746118	0.088257
6	N Wales & Mersey	- 3.307812	2.791637	-3.139276	2.879894	0.168536	0.088257
7	East Midlands	- 0.308635	2.791637	-0.843544	2.879894	- 0.534909	0.088257
8	Midlands	2.990958	2.791637	3.119104	2.879894	0.128146	0.088257
9	Eastern	1.110745	2.791637	0.637046	2.879894	- 0.473699	0.088257
10	South Wales	6.885043	2.791637	7.959162	2.879894	1.074119	0.088257
11	South East	5.568235	2.791637	5.625208	2.879894	0.056973	0.088257
12	London	7.405345	2.791637	6.993935	2.879894	- 0.411410	0.088257
13	Southern	7.570174	2.791637	8.382088	2.879894	0.811914	0.088257
14	South Western	10.123037	2.791637	15.566653	2.879894	5.443617	0.088257

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 final 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 2026/27 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2025. The specific and generic ALFs that will apply to the 2025/26 TNUoS Tariffs have been published in the following places:

- Final Annual Load Factors for 2025/26 TNUoS Tariffs: neso.energy/document/352566/download
- Specific ALFs in excel format: neso.energy/document/352541/download

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 DESNZ 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 (affecting locational tariffs) will be fixed using the TEC register as of 31 October 2025, as required by the CUSC 14.15.6 and no further changes to Contracted TEC will be made after that point.

Table 28 shows the contracted generation changes that are expected since the 2025/26 position, using data from the March 2025 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100 MW TEC are not chargeable and are not included in this table.

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Aberarder Wind Farm	0.1	ABED10	1
Aberthaw (Tertiary)	-57	ABTH20	21
Akku Tealing Battery Storage	-500.0	TEAL20	5
Arecleoch Windfarm Extension	72.8	AREX10	10
Berkswell Energy Storage	200.0	BESW20	18
Bhlaraidh Extension Wind Farm	100.8	BLEX10	3
Blackhillock Battery	349.0	BLHI40	1
Botley West - Cote Solar Power Station	840	COWL40	25
Bradford West 100MW	100.0	BRAW20	15
Braintree (Tertiary)	49.9	BRAI4A	24
Braintree PP	7.1	BRAI4A	24
Bramford Tertiary	57	BRFO40	18
Bridgwater (tertiary)	57.0	BRWA4A	26
Bryn Tilti	106	LEGA40	18
Builth Wells	133.0	POAB41	21
Canterbury Tertiary	7.1	CANT40	24
Carnedd Wen Wind Farm	150.0	TRAW10	16
Chirmorie Wind Farm	80	CHMO10	10
Cockenzie BESS	102.0	COCK4Q	11
Corriegarth 2 Wind Farm	70	COGA10	1
Dealanach WLC WF	12.0	HORI10	12
Deeside Power Station	190	CONQ40	16
Dolyfardyn	165.0	LEGA40	18
Drakelow	-57	DRAK40	18
Drakelow Green Energy Centre	400.0	DRAK40	18
Drax (Biomass)	-1905	DRAX40	15
Drax (Coal)	-2001.0	DRAX40	15
Drax Power Station	3906	DRAX40	15
Drongan Battery Storage	100.0	COYL20	10

Power Station	MW Change	Node	Generation Zone
East Claydon Solar PV	500	ECLA40_EME	18
Eccles BESS	500.0	ECCL40	11
Eggborough CCGT and BESS	1999	EGGB40	15
Elstree (tertiary)	-49.9	ELST40	25
Elvanfoot (9.8 MW) Energy Storage	-9.8	ELVA40	11
Enderby Tertiary	-57.0	ENDE40	18
Eppynt Common	189.5	POAB41	21
Faw Side Community Wind Farm	-250.0	FASI10	11
Flash Solar Farm	360	STAY40	16
Fleet EGH (Tertiary)	47.5	FLEE40	25
Fleet Solar PV	57	FLEE40	25
Frodsham Solar Park	100.0	FROD2A	16
Fron Goch	252.7	POAB41	21
Gammidge PV & BESS Park	-40.9	GREN40_EME	18
Glen Ullinish Wind Farm	49.9	GLNU10	4
Gresham House Cockenzie BESS	240.0	COCK20	11
Hareshaw Rig Wind Farm	40	EWEH1Q	12
Heathland Wind Farm	80.0	HLND10	11
High Constellation Windfarm	-50	CRSS10	7
High Marnham (Tertiary)	-57.0	HIGM40	16
Hinkley Point B	-1061	HINP40	26
Hopsrig Wind Farm	48.0	HORI10	12
Hornsea Power Station 3	2250	NORM40	18
Hunterston	-1020.0	HUER40	10
Immingham	-50	HUMR40	15
Ironbridge - New Connection	-49.9	IRON40	18
Keadby	155	KEAD40	16
Keadby South Power Station	910.0	KEAD40	16
Kirkby (Tertiary)	-57	KIBY20	15
Lairg II Wind Farm	50.0	LAIS1B	1
Lakeside Energy Drax	-0.9	DRAX10	15
Lamford Hill	20.0	BENB10	10
Legacy Green Energy Centre	400	LEGA40	18
Llwynygog	125.0	LEGA40	18
Lochay (Part of Killin Cascade Hydro Scheme)	4.2	LOCH10	6
Lochgoin Solar Farm	-89.0	WLEE20	10
Loganhead Windfarm	36	HORI10	12
Mannington PP	-2.4	MANN40	26
Middleton BESS	200	MIDL40	14
Moel y Llyn	251.0	LEGA40	18
Moelfre Energy Park	158.4	BODE40	16
Moray West Offshore Windfarm	60.0	BLHI40	1
Mwdwl Eithin Energy Park	81.2	BODE40	16
NeuConnect Interconnector	1400.0	GRAI40	24
New Marton GEC	550	CANT40	24
North Kyle New Cumnock	-133.0	NECU10	10
NorthFleet Tertiary	49.9	NFLE40	24
Pembroke (spare bay)	120.0	PEMB40	20
Pentland Floating Offshore Wind Farm	-100	DOUN10	1
Penwortham Green Energy Centre	400.0	PEWO40	15
Plas Power Estate North Tertiary	57	LEGA40	18
Rampion Extension Offshore Wind Farm	1200.0	BOLN40	25
Ratcliffe on Soar	-999.7	RATS40	18
Rayleigh 1 Tertiary	-57.0	RAYL40	24
Rayleigh 2 Tertiary	-49.9	RAYL40	24
Rye House (Tertiary)	-49.9	RYEH40	24
Scoop Hill Wind Farm	-500	SCOP10	12
SHBEC	83.0	SHBA40	15

Power Station	MW Change	Node	Generation Zone
Sizing John (Rainhill)	85.5	RAIN20_ENW	15
Staythorpe (BESS and PV)	437.0	STAY40	16
Strathy Wood	63.5	STWO10	1
Sulgrave Solar PV	129.8	ECLA40_EME	18
Sundon Battery	0.5	SUND40	18
Swansea North	49.9	SWAN4A	21
Tangy IV WF	96	TNGF10	7
Thornton Facility	100.0	THTO40	15
Thorpe Marsh 1 (Tertiary)	-49.9	THOM41	16
Thorpe Marsh Energy Park	1400.0	THOM41	16
TINZ Project Nene 1 (Landulph)	-1	LAND4A	27
Uskmouth - New Connection	120.0	USKM20	21
Walpole 2 (tertiary)	-100	WALP40_EME	17
WELBAR ENERGY STORAGE	349.9	HAMH40_EME	18
West Burton	-49.9	WBUR40	16
Whitehill Battery Storage	200.0	EERH20	9
Whitelaw Brae BESS	1	CLYS2R	11
Whitson	49.9	WHSO20	21
Willington	57	WILE40	18
Willington Green Energy Centre	400.0	WILE40	18
Windy Standard III Wind Farm	10.5	DUNH1Q	10
WORSET LANE BESS	200.0	HARM20	13
Zenobe Blackhillock 300 MW	100	BLHI20	1
Zenobe Coalburn Battery Storage	200.0	COAL40	11
Zenobe Eccles Battery Storage	400	ECCL40	11
Zenobe Stalybridge Project	150.0	STAL20	16

Appendix F: Transmission Company Revenues

Transmission Owner revenue forecasts

The revenue forecast has been based on data submissions received from Onshore and Offshore TOs in January 2025. 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 transmission 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 ONTOs, 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.

Compared to the 2025/26 Final Tariffs, there has been an increase in ONTO Allowed Revenues, OFTO allowed revenue and Interconnector costs. There has also been an increase to the adjustment term owing to updates to the latest view of 2024/25 allowed revenue using latest actual data.

Table 29 NESO revenue breakdown

Term	NESO TNUoS Other Pass-Through Initial Forecast	August Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.67			
Network Innovation Competition Fund (NICFt)	0.00			
Strategic Innovation Fund (SIFt)	62.90			
The Adjustment Term (ADJt)	27.02			
Offshore Transmission Revenue (OFTOt) and Interconnectors Revenue Adjustment (TICFt and TICPt)	1,039.39			
Site Specific Charges Discrepancy (DISt)	0.00			
Termination Sums (TSt)	0.00			
NGET revenue pas-through (NGETTOt)*	2,590.04			
SPT revenue pass-through (TSPt)	899.17			
SHETL revenue pass-through (TSHt)	1,573.04			
NESO Bad debt (BDt)	0.03			
NESO other pass-through items (LFt + ITCt etc)	47.35			
NESO legacy adjustment (LARt)	0.00			
Total	**6,239.61**	**0.00**	**0.00**	**0.00**

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 revenue breakdown in January 2025 as required by STCP 24-1. All three TOs expect their revenues to increase between 2026/27 and 2030/31.

For NGET, the forecasted RIIO-ET3 period is based on allowed revenues for 2025/26 adjusted for long term inflation and does not represent any future business plan assumptions.

For SPT, the revenue forecasts for the RIIO-ET3 period reflect the latest view of the price control as per the recent business plan submission.

For SHET, the forecasted RIIO-ET3 period reflects the latest SSEN-Transmission business plan submission to Ofgem which presents a minimum ET3 totex investment plan of £22bn (23/24 prices). This investment is made up of ex ante base line ET3 totex and committed spend on ASTI and LOTI Projects. However, please note that ASTI costs remain subject to negotiation and finalisation, particularly for those ASTI projects which are in the early development stages. Revenue has been calculated by applying the financial parameters set out by Ofgem in the published Business Plan Financial Model (BPFM).

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2026/27 is forecast to be £1.11bn, an increase of £100.4m since 2025/26. Revenues have been adjusted using updated revenue submissions provided by the OFTOs in addition to the latest RPI and CPI data (as part of the calculation of each OFTO’s inflation term, as defined in the relevant OFTO licence). The 2026/27 forecast includes £158.5m of forecast revenue (14% of total) for OFTOs yet to asset transfer.

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.

The Interconnector Adjustment forecast is based on figures submitted by Interconnectors in January 2025.

Table 30 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31			
Inflation		PI_t	380.53			
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	1,928.32			
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00			
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**2,590.04**			
SONIA	B1	It-1	0.04			
Allowed Revenue	B2	AR_{t-1}	2,397.89			
Recovered Revenue	B4	RR_{t-1}	2,397.89			
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**			
Legacy pass-through	C1	LP_t	0.00			
Legacy MOD	C2	$LMOD_t$	0.00			
Legacy K correction	C3	LK_t	0.00			
Legacy TRU term	C4	$LTRU_t$	0.00			
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00			
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00			
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00			
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00			
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**0.00**			
Site Rental Charges			**0.00**			
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**2,590.04**			

Table 31 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31			
Inflation		PI_t	380.53			
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	669.45			
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00			
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**899.17**			
SONIA	B1	It-1	0.00			
Allowed Revenue	B2	AR_{t-1}	0.00			
Recovered Revenue	B4	RR_{t-1}	0.00			
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**			
Legacy pass-through	C1	LP_t	0.00			
Legacy MOD	C2	$LMOD_t$	0.00			
Legacy K correction	C3	LK_t	0.00			
Legacy TRU term	C4	$LTRU_t$	0.00			
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00			
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00			
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00			
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00			
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**0.00**			
Site Rental Charges			**0.00**			
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**899.17**			

Table 32 SHET revenue breakdown

Transmission Revenue Forecast			SHE Transmission Initial Forecast	SHE Transmission August Forecast	SHE Transmission November Draft	SHE Transmission January Final
Inflation 2018/19		$PI_{2018/19}$	283.31			
Inflation		PI_t	380.53			
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	1,171.15			
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00			
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**1,573.04**			
SONIA	B1	It-1	0.04			
Allowed Revenue	B2	AR_{t-1}	1,191.62			
Recovered Revenue	B4	RR_{t-1}	1,191.62			
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**			
Legacy pass-through	C1	LP_t	0.00			
Legacy MOD	C2	$LMOD_t$	0.00			
Legacy K correction	C3	LK_t	0.00			
Legacy TRU term	C4	$LTRU_t$	0.00			
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00			
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	$LEDR_t$	0.00			
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	$LSFI_t$	0.00			
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRI_t	0.00			
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	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**	**0.00**			
Site Rental Charges			**0.00**			
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**1,573.04**			

Table 33 Offshore Revenues

Offshore Transmission Revenue Forecast (£m)	Year						
Regulatory Year	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Notes
Barrow	6.7	7.0	7.8	8.5	8.8	9.1	Current revenues plus indexation
Gunfleet Sands	8.4	8.7	9.7	10.7	11.1	11.4	Current revenues plus indexation
Walney 1	15.3	15.6	17.8	19.4	20.3	19.9	Current revenues plus indexation
Robin Rigg	9.4	9.8	10.9	12.0	12.4	12.7	Current revenues plus indexation
Walney 2	15.1	16.3	18.3	20.0	20.9	21.5	Current revenues plus indexation
Sheringham Shoal	23.4	24.2	26.7	29.5	30.0	31.6	Current revenues plus indexation
Ormonde	14.1	14.7	16.2	17.9	18.6	19.1	Current revenues plus indexation
Greater Gabbard	32.1	33.2	37.0	38.8	41.6	43.5	Current revenues plus indexation
London Array	44.7	46.8	52.6	57.3	59.1	60.3	Current revenues plus indexation
Thanet	20.8	21.6	24.0	26.3	27.4	28.1	Current revenues plus indexation
Lincs	30.0	32.5	34.0	40.9	40.1	41.2	Current revenues plus indexation
Gwynt y mor	32.9	39.8	37.6	37.4	78.8	40.4	Current revenues plus indexation
West of Duddon Sands	25.3	25.5	28.5	30.3	32.3	33.1	Current revenues plus indexation
Humber Gateway	14.4	13.3	15.0	16.6	17.4	17.4	Current revenues plus indexation
Westermost Rough	14.1	14.7	16.5	18.0	18.6	19.1	Current revenues plus indexation
Burbo Bank Extension	14.1	14.7	16.4	17.7	18.4	19.0	Current revenues plus indexation
Dudgeon	19.6	20.8	22.6	24.9	26.2	26.9	Current revenues plus indexation
Race Bank	27.4	28.9	32.5	35.4	36.5	37.6	Current revenues plus indexation
Galloper	17.1	17.8	20.1	21.9	22.5	23.2	Current revenues plus indexation
Walney 3	13.5	14.1	15.9	17.3	17.8	18.3	Current revenues plus indexation
Walney 4	13.5	14.1	15.9	17.3	17.8	18.3	Current revenues plus indexation
Hornsea 1A		18.4	20.6	22.2	22.9	23.9	Current revenues plus indexation
Hornsea 1B		18.4	20.6	22.2	22.9	23.9	Current revenues plus indexation
Hornsea 1C	137.1	18.4	20.6	22.2	22.9	23.9	Current revenues plus indexation
Beatrice		21.1	24.4	25.7	26.5	27.1	Current revenues plus indexation
Rampion		15.5	17.4	19.7	20.3	20.9	Current revenues plus indexation
East Anglia 1			47.4	51.8	54.8	56.3	Current revenues plus indexation
Hornsea 2A				25.3	27.3	28.0	Current revenues plus indexation
Hornsea 2B		68.3		25.3	27.3	28.0	Current revenues plus indexation
Hornsea 2C			138.7	25.3	27.3	28.0	Current revenues plus indexation
Triton Knoll				41.3	42.7	45.4	Current revenues plus indexation
Moray East				28.2	50.0	51.6	Current revenues plus indexation
Seagreen 1				52.6	89.6	44.3	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2025/26						119.5	NESO Forecast
Forecast to asset transfer to OFTO in 2026/27						39.0	NESO Forecast
Offshore Transmission Pass-Through	**549.0**	**594.3**	**765.6**	**879.8**	**1,010.9**	**1,111.3**	

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

Sensitivity Analysis

Purpose

We are conscious there are uncertainties over the allowed revenue forecasts over the next five years. To help industry to understand the potential implications of the ongoing changes, we have undertaken further modelling the impact of additional revenue on the TDR.

Caveats

The methodology is subject to change due to ongoing CUSC modification proposals. All tariffs in this section are to illustrate mathematically how tariffs may evolve. In presenting sensitivities, it does not infer about our view of the future, likelihoods of certain scenarios or changes to policy.

Whilst every effort is made to ensure the accuracy of the information, it is subject to several estimates and forecasts and may not bear relation to the indicative, or future, tariffs that NESO will publish at a later date.

Impact of additional revenue on TDR

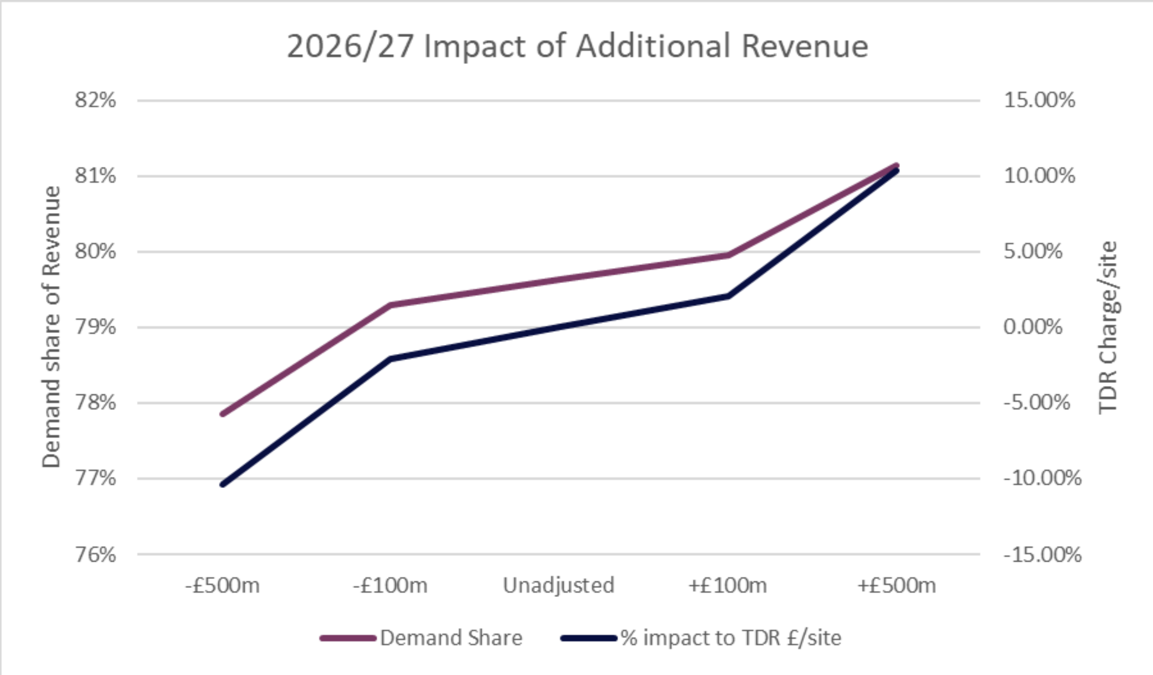
This analysis is based on the year 2026/27.
The analysis assumes that the increase/decrease in revenue stems from onshore TOs or pass-through costs rather than OFTO revenue. This is because only a relatively small proportion of each OFTO's revenue impacts the revenue to be collected via the demand residual.
The total TDR charge/site is used as the measure because the impact on the individual site types is proportionately the same, with each site increasing/decreasing by the same percentage.
The 2026/27 Transport and Tariff model was run five times with a -£500m adjustment, -£100m adjustment, +100m adjustment, +£500m adjustment and then no adjustment. The results of these runs can be seen in Table S1.

Table S1 Impact of Additional Revenue on Transmission Demand Residual

	2026/27				
	-£500m	-£100m	Unadjusted	+£100m	+£500m
Revenue (£m)	5738.94	6138.94	6238.94	6338.94	6738.94
Generation Share*	6.0%	5.6%	5.5%	5.4%	5.1%
Demand Share	78%	79%	80%	80%	81%
% impact to TDR £/site	-10.35%	-2.07%	0.00%	2.07%	10.35%

*not including PARC

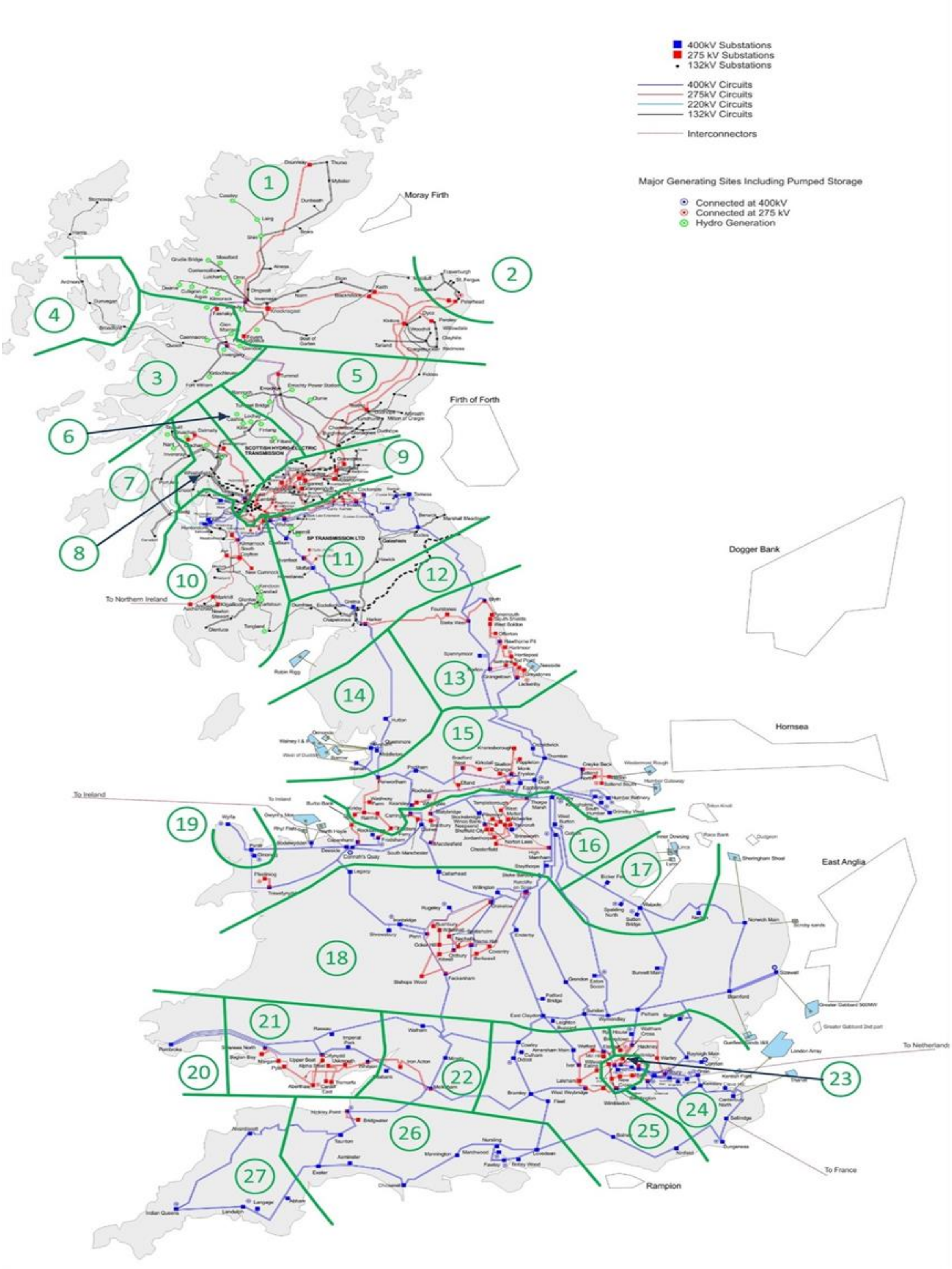
Figure S1 Impact of Additional Revenue on Transmission Demand Residual



The average TDR charge increases or decreases in line with the demand share of the revenue. All else remaining unchanged for every additional or reducing £100m the average TDR charge/site will increase or decrease by 2.07% respectively.

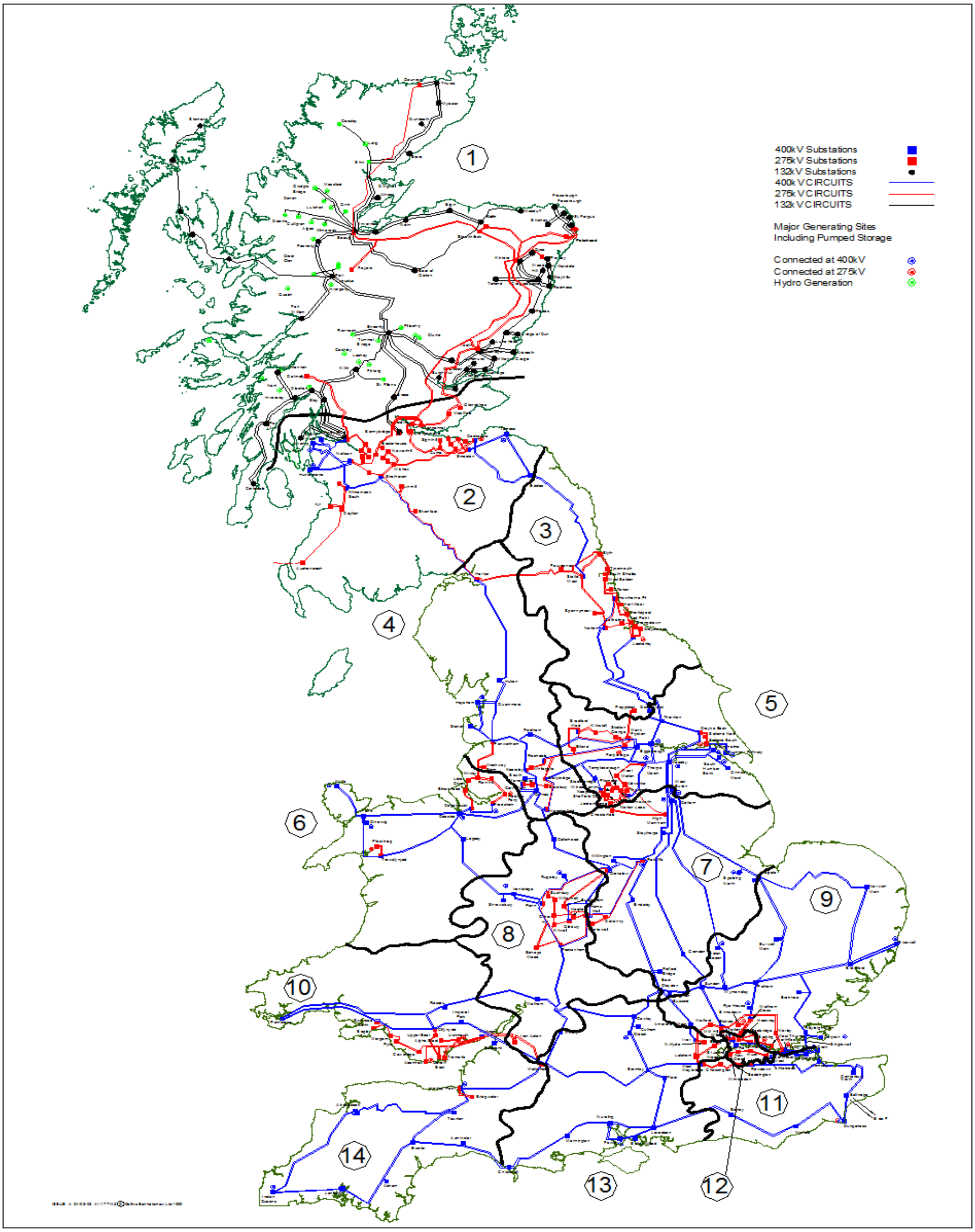
Appendix G: Generation Zones Map

Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to [Electricity Ten Year Statement 2024 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
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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.

2026/27 TNUoS Tariff Forecast					
		April 2025	August 2025	Draft Tariffs November 2025	Final Tariffs January 2026
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	
	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 ONTOs
	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	30 April 2025	Publication of Initial Forecast of TNUoS Tariffs for 2026/27

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