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Final TNUoS Tariffs for 2026/27

National Energy System Operator

NESO
National Energy System Operator

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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 Final 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 the Final 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 £7.61bn, a decrease of £44.87m since the Draft forecast. There has been a net decrease of £9.97m in the allowed revenue for the Onshore Transmission Owners (ONTOs) based on their January revenue submission as per STCP24-1. In addition, there has been a £49.16m decrease in the adjustment term and other passthrough items, offset by a £14.27m increase in allowed revenues for Offshore Transmission Owners (OFTOs).

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.23bn for 2026/27, an increase of £2.3m since the Draft forecast. This is primarily driven by an increase in expected revenue from offshore local tariffs.

The generation charging base has been updated to 101.6 GW based on our best view on generation projects for 2026/27, a decrease of 1.2 GW since the Draft forecast. The average generation tariff is £12.12/kW, an increase of £0.17/kW since the Draft forecast due to the increase in generation revenue to be collected and the decrease in the charging base.

Demand tariffs

Revenue to be collected from demand users is forecast to be £6.38bn for 2026/27, a £47m decrease compared to the Draft forecast. The reduction in demand revenue is the result of the decrease in total TNUoS revenue to be collected.

The TNUoS cost for the average domestic household is £83.24 for 2026/2027 (accounting for 8.8% of the typical annual electricity bill), a decrease of £0.58 since the Draft forecast.

In 2026/27, it is forecast that £20.44m would be payable to embedded generators (<100 MW) through the Embedded Export Tariff (EET), a decrease

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

of £119k compared to the Draft forecast. This is due to a reduction in the average EET. The average EET is £3.05/kW, which is a decrease of £0.02/kW since the Draft Forecast.

The average gross HH demand tariff for 2026/27 is £2.79/kW, an increase of £0.01/kW compared to the Draft forecast and the average NHH demand tariff is 0.38p/kWh, an increase of 0.001p/kWh since the Draft forecast.

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2027/28 is available on our website[2].

Our next TNUoS tariff publication will be the initial forecast of 2027/28 TNUoS tariffs, which will be published in April 2026.

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:

Email: TNUoS.Queries@neso.energy

[2] neso.energy/document/376486/download

Charging Methodology Changes

This Report

This report contains the Final TNUoS tariffs for the charging year 2026/27.

The TNUoS tariff setting methodology defined in the CUSC is subject to open governance. We are obliged to comply with the latest approved CUSC changes, applicable from 1st April 2026, in the Final Tariffs for 2026/27.

This section summarises any key changes to the methodology.

Charging Methodology Changes

CMP463: 'Stabilising the Specific Onshore Expansion Factors from 1st April 2026' has been approved by Ofgem for implementation on 1 April 2026. This modification seeks to hold Specific Onshore Expansion Factors at 2025/26 levels, to avoid large, unexpected increases caused by the new price control, ahead of a larger more fundamental review of TNUoS.

No other changes have been approved to the charging methodology this year. Approved CUSC methodology changes that affect 2026/27 tariffs are summarised in the CUSC modifications Table 24.

Reformed National Pricing programme and electricity network charging

REMA has concluded and in July 2025, Ofgem published an open letter[3] outlining their initial thinking on reforming network charging signals to align with the UK Government's decision to retain a single GB-wide electricity market[4].

Please note that this ongoing work has not resulted in any changes to the methodology used to calculate the 2026/27 Final tariffs.

TNUoS Task Force and electricity network charging

In May 2022, Ofgem published an open letter asking NESO to work with industry to establish Task Force membership. 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.

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[3] ofgem.gov.uk/sites/default/files/2025-07/open-letter-reforming-network-charging-signals.pdf
[4] gov.uk/government/publications/review-of-electricity-market-arrangements-rema-summer-update-2025/review-of-electricity-market-arrangements-rema-summer-update-2025-accessible-webpage

Please note that this ongoing work has not resulted in any changes to the methodology used to calculate the 2026/27 Final tariffs.

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.

Ofgem published an update to their Final RIIO-ET3 Determinations on 16 December 2025. Using this, and input data from the onshore TOs, we have calculated the parameters and tariffs, which have been used within this publication.

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

Component	Description	Outcomes for 2026/27 onwards
Maximum Allowed Revenue	The MAR for onshore TOs in the new price control period is determined during the negotiations up to the start of the price control period.	The Final Tariffs are based on the allowed revenues which were submitted by the Transmission Owners, in line with STCP24-1 requirements. Please see Allowed Revenues for more information.
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.	The number of generation zones remains at 27, pending the outcome of "CMP419: Generation Zoning Methodology Review".

Component	Description	Outcomes 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 continues to increase by CPIH as per the CUSC, and the expansion factors are unchanged; pending the outcome of "CMP315/375: Expansion Constant & Expansion Factor Review" Following the approval of CMP463 (Stabilising the Specific Onshore Expansion Factors), inputs to the HVDC & Subsea Link specific expansion factors have been fixed at the RIIO-ET2 levels.
Locational Onshore Security Factor	The security factor has been recalculated in preparation for the start of RIIO-ET3 period.	The Locational Onshore Security Factor has been recalculated as 1.75, this will remain constant throughout the RIIO-ET3 period.
Onshore Local Substation Tariffs	Local Substation tariffs have been recalculated in preparation for the start of the price control based on TO asset costs.	The local substation tariffs have been updated based on onshore TO data and Ofgem's Final RIIO-ET3 Determinations. The recalculated tariffs have been used within this Final Tariff publication.

Component	Description	Outcomes for 2026/27 onwards
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.	The offshore tariffs have been recalculated to adjust for differences in actual OFTO revenue to forecast revenue within RIIO-T2. The Offshore substation discount has also been finalised, using, data provided to us by the TO's and Ofgem's final RIIO-ET3 determinations.
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.	The AGIC has been updated for Final Tariffs. The updated value is based on updated scheme data provided to us by the TO's and Ofgem's final RIIO-ET3 determinations.
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.	The RIIO-ET3 TDR Banding Thresholds were calculated and finalised ahead of inclusion in the Initial Tariffs, therefore there have been no changes to the banding thresholds in this publication. Please refer to table TB in the published tables excel spreadsheet[5] for the new banding thresholds.

[5] neso.energy/document/376341/download

Generation Tariffs

Generation Wider Tariffs

Onshore Local Substation Tariffs

Onshore Local Circuit Tariffs

Offshore Local Tariffs

Generation Tariffs Summary

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

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	2026/27 Draft	2026/27 Final	Change since last forecast
Adjustment	- 2.906397	- 2.476760	0.429637
Average Generation Tariff*	11.949165	12.117642	0.168477

*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 increased by £0.17/kW, due to the increase in generation revenue to be collected and the 1.2 GW decrease in the generation charging base, compared to the Draft forecast. The generation adjustment has increased by £0.43/kW, decreasing in magnitude, to become less negative; this is because the expected decrease in revenue to be collected from wider tariffs outweighs the expected decrease in charging base, meaning that less of an adjustment is required to decrease the overall generation tariff, to ensure compliance with the €2.50/MWh cap.

Generation Wider Tariffs

The following section summarises the wider generation tariffs for 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 publication are:

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

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

Table 2 Generation Wider Tariffs

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Example tariffs for a generator of each technology type: Conventional Carbon 40%	Conventional Low Carbon 75%	Intermittent 45%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	3.628060	26.532717	17.674559	- 2.476760	18.834210	38.725397	27.137522
2	East Aberdeenshire	5.307833	14.646253	17.674559	- 2.476760	15.759398	31.490322	21.788613
3	Western Highlands	3.677990	26.123017	17.385831	- 2.476760	18.604769	38.179324	26.664429
4	Skye and Lochalsh	3.612174	26.123017	24.924783	- 2.476760	21.554534	45.652460	34.203381
5	Eastern Grampian and Tayside	6.568239	20.511538	12.542262	- 2.476760	17.312999	32.017395	19.295694
6	Central Grampian	5.878875	20.594053	12.650220	- 2.476760	16.699824	31.497875	19.440784
7	Argyll	4.946318	19.010365	22.336904	- 2.476760	19.008466	39.064236	28.414808
8	The Trossachs	4.213182	19.010365	10.548892	- 2.476760	13.560125	26.543088	16.626796
9	Stirlingshire and Fife	3.459485	18.428090	10.073886	- 2.476760	12.383515	24.877679	15.889767
10	South West Scotlands	2.724127	18.071712	9.859646	- 2.476760	11.419910	23.660797	15.515156
11	Lothian and Borders	3.972256	18.071712	3.245525	- 2.476760	10.022391	18.294805	8.901035
12	Solway and Cheviot	2.267394	10.990377	5.769218	- 2.476760	6.494472	13.802635	8.238128
13	North East England	5.317903	7.346053	3.552395	- 2.476760	7.200522	11.903078	4.381359
14	North Lancashire and The Lakes	2.097904	7.346053	0.189240	- 2.476760	2.635261	5.319924	1.018204
15	South Lancashire, Yorkshire and Humber	5.666724	2.322079	0.171306	- 2.476760	4.187318	5.102829	- 1.260518
16	North Midlands and North Wales	3.735152	0.965658	-	- 2.476760	1.644655	1.982636	- 2.042214
17	South Lincolnshire and North Norfolk	0.194059	3.127359	-	- 2.476760	- 1.031757	0.062818	- 1.069448
18	Mid Wales and The Midlands	0.194313	4.707306	-	- 2.476760	- 0.399525	1.248033	- 0.358472
19	Anglesey and Snowdon	5.275539	0.562440	-	- 2.476760	3.023755	3.220609	- 2.223662
20	Pembrokeshire	7.221420	- 8.116578	-	- 2.476760	1.498029	- 1.342774	- 6.129220
21	South Wales & Gloucester	2.591993	- 9.044134	-	- 2.476760	- 3.502421	- 6.667868	- 6.546620
22	Cotswold	0.162572	4.908322	- 13.506660	- 2.476760	- 5.753523	- 12.139607	- 13.774675
23	Central London	- 4.192754	4.908322	- 6.357476	- 2.476760	- 7.249176	- 9.345749	- 6.625491
24	Essex and Kent	- 3.370754	4.908322	-	- 2.476760	- 3.884185	- 2.166273	- 0.268015
25	Oxfordshire, Surrey and Sussex	- 1.335120	- 1.530477	- 0.136243	- 2.476760	- 4.478568	- 5.095981	- 3.301718
26	Somerset and Wessex	- 3.581527	- 3.263601	-	- 2.476760	- 7.363727	- 8.505988	- 3.945380
27	West Devon and Cornwall	- 4.327454	- 13.295891	-	- 2.476760	- 12.122570	- 16.776132	- 8.459911

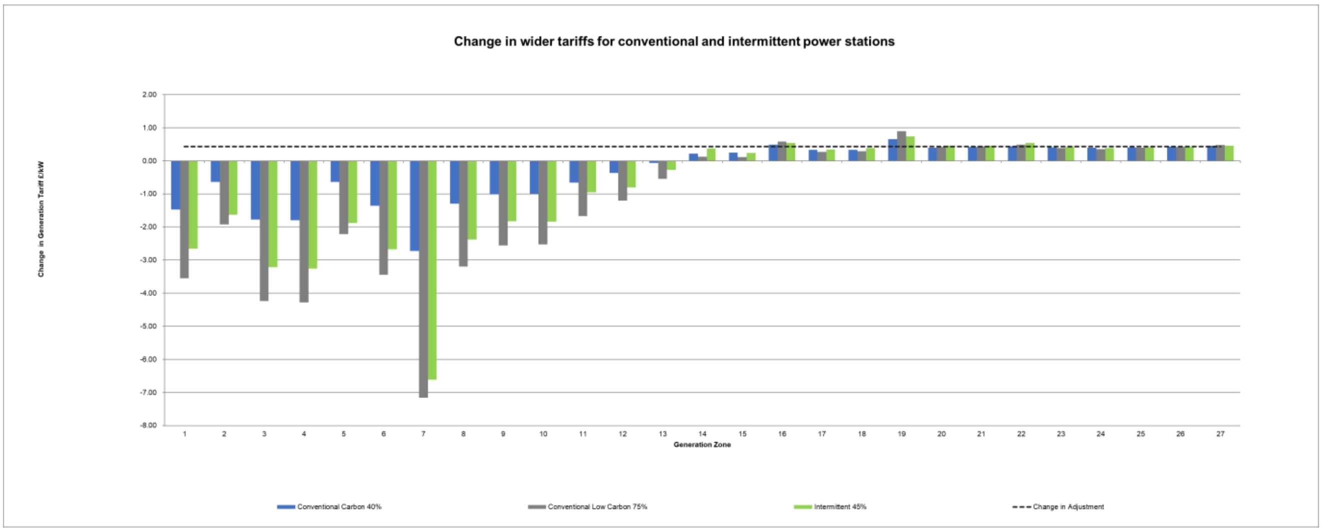
Changes to Wider Tariffs since the Draft Forecast

The following section provides details of the wider generation tariffs for 2026/27 and explains how these have changed since the Draft Forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only.

Table 3 Generation Wider Tariff Changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			Change in Adjustment
		2026/27 Draft	2026/27 Final	Change	2026/27 Draft	2026/27 Final	Change	2026/27 Draft	2026/27 Final	Change	
1	North Scotland	20.305263	18.834210	-1.471053	42.275278	38.725397	-3.549881	29.785212	27.137522	-2.647690	0.429637
2	East Aberdeenshire	16.400588	15.759398	-0.641190	33.415577	31.490322	-1.925255	23.414464	21.788613	-1.625851	0.429637
3	Western Highlands	20.385553	18.604769	-1.780784	42.418711	38.179324	-4.239387	29.879558	26.664429	-3.215129	0.429637
4	Skye and Lochalsh	23.349684	21.554534	-1.795150	49.928283	45.652460	-4.275823	37.455292	34.203381	-3.251911	0.429637
5	Eastern Grampian and Tayside	17.951169	17.312999	-0.638170	34.229992	32.017395	-2.212597	21.173031	19.295694	-1.877337	0.429637
6	Central Grampian	18.062404	16.699824	-1.362580	34.947331	31.497875	-3.449456	22.112003	19.440784	-2.671219	0.429637
7	Argyll	21.732399	19.008466	-2.723933	46.227305	39.064236	-7.163069	35.028039	28.414808	-6.613231	0.429637
8	The Trossachs	14.851193	13.560125	-1.291068	29.735545	26.543088	-3.192457	19.010448	16.626796	-2.383652	0.429637
9	Stirlingshire and Fife	13.402420	12.383515	-1.018905	27.431465	24.877679	-2.553786	17.720786	15.889767	-1.831019	0.429637
10	South West Scotlands	12.412375	11.419910	-0.992465	26.191213	23.660797	-2.530416	17.350715	15.515156	-1.835559	0.429637
11	Lothian and Borders	10.680255	10.022391	-0.657864	19.962865	18.294805	-1.668060	9.857003	8.901035	-0.955968	0.429637
12	Solway and Cheviot	6.859443	6.494472	-0.364971	15.008608	13.802635	-1.205973	9.045510	8.238128	-0.807382	0.429637
13	North East England	7.261425	7.200522	-0.060903	12.445492	11.903078	-0.542414	4.656630	4.381359	-0.275271	0.429637
14	North Lancashire and The Lakes	2.417441	2.635261	0.217820	5.195422	5.319924	0.124502	0.646487	1.018204	0.371717	0.429637
15	South Lancashire, Yorkshire and Humber	3.941750	4.187318	0.245568	4.992385	5.102829	0.110444	-1.501290	-1.260518	0.240772	0.429637
16	North Midlands and North Wales	1.151532	1.644655	0.493123	1.401412	1.982636	0.581224	-2.585123	-2.042214	0.542909	0.429637
17	South Lincolnshire and North Norfolk	-1.367846	-1.031757	0.336089	-0.206246	0.062818	0.269064	-1.412911	-1.069448	0.343463	0.429637
18	Mid Wales and The Midlands	-0.728886	-0.399525	0.329361	0.954492	1.248033	0.293541	-0.742055	-0.358472	0.383583	0.429637
19	Anglesey and Snowdon	2.367968	3.023755	0.655787	2.327215	3.220609	0.893394	-2.958795	-2.223662	0.735133	0.429637
20	Pembrokeshire	1.105634	1.498029	0.392395	-1.752571	-1.342774	0.409797	-6.581232	-6.129220	0.452012	0.429637
21	South Wales & Gloucester	-3.921929	-3.502421	0.419508	-7.105363	-6.667868	0.437495	-6.999383	-6.546620	0.452763	0.429637
22	Cotswold	-6.184360	-5.753523	0.430837	-12.624948	-12.139607	0.485341	-14.309815	-13.774675	0.535140	0.429637
23	Central London	-7.654724	-7.249176	0.405548	-9.730648	-9.345749	0.384899	-7.035375	-6.625491	0.409884	0.429637
24	Essex and Kent	-4.273136	-3.884185	0.388951	-2.516733	-2.166273	0.350460	-0.648164	-0.268015	0.380149	0.429637
25	Oxfordshire, Surrey and Sussex	-4.883271	-4.478568	0.404703	-5.485268	-5.095981	0.389287	-3.710756	-3.301718	0.409038	0.429637
26	Somerset and Wessex	-7.788382	-7.363727	0.424655	-8.922298	-8.505988	0.416310	-4.364288	-3.945380	0.418908	0.429637
27	West Devon and Cornwall	-12.582659	-12.122570	0.460089	-17.255135	-16.776132	0.479003	-8.913866	-8.459911	0.453955	0.429637

Figure 1 Variation in generation wider zonal tariffs



Locational Changes

Locational tariffs have been impacted by the reduction in the Locational Onshore Security Factor, the implementation of CMP463 and some minor revisions to the nodal demand data. This means that there have been changes in the overall tariffs across each generation zone and in general has resulted in a decrease to the North-South divide. In particular, the implementation of CMP463 has resulted in a large decrease to tariffs in zone 7, due to its impact on the link specific expansion factors for the Western HVDC Link and Crossaig subsea cable.

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 £0.43/kW since the Draft Forecast, decreasing in magnitude, to become less negative. This is because the decrease in revenue expected to be collected from wider tariffs outweighs the expected decrease to the charging base, meaning that there is less of an 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.

Onshore Local Substation tariffs have been updated as part of the RIIO-ET3 parameter refresh. They have been updated based on onshore TO data and Ofgem's Final RIIO-ET3 Determinations (as published 16 December), resulting in a decrease since Draft Tariffs.

Tariffs for subsequent years will then 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	0.406178	0.167831	0.122333
<1320 MW	Redundancy	0.858134	0.372158	0.259397
≥1320 MW	No redundancy	-	0.510552	0.356053
≥1320 MW	Redundancy	-	0.780813	0.533526

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.

The 2026/27 onshore local circuit tariffs have been finalised. The updated tariffs are listed below in Table 5. A limited number of onshore local circuit tariffs have changed since Draft Tariffs, due to the reduction in Locational Onshore Security Factor, the implementation of CMP463 (Stabilising the Specific Onshore Expansion Factors) and a further review of the local network. This has also resulted in two new local circuit tariffs being included (Marston Vale and Yaxley).

Table 5 Onshore Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.781281	Dunhill	1.853914	Lochay	0.395840
Aberdeen Bay	1.979201	Dunlaw Extension	0.552300	Luichart	0.730641
Achruach	-1.688946	Dunmaglass	1.131444	Marchwood	0.484012
Aigas	0.914658	Edinbane	8.906166	Marston Vale	-0.634131
An Suidhe	-1.080984	Enoch Hill	0.791681	Middle Muir	2.747132
Arecleoch	1.979201	Ewe Hill	1.956469	Middleton	0.198287
Arecleoch Extension	1.560493	Fallago	-0.070115	Millennium Wind	2.074890
Ayrshire Grid Collector	0.175914	Farr	4.499496	Mossford	3.936831
Beinneun Wind Farm	1.755575	Fernoch	5.576958	Nant	-1.618164
Benbrack	0.947818	Ffestiniog	0.281261	Pont Abraham	-0.149034
Bhlaraidh Wind Farm	0.792780	Fife Grid Services	0.197495	Rhigos	0.129859
Black Hill	1.986337	Finlarig	0.395840	Rocksavage	0.019158
Blackcraig	7.205463	Foyers	0.361621	Saltend	-0.020052
Blacklaw	2.177122	Galawhistle	1.359052	Sandy Knowe	5.957759
Blacklaw Extension	4.735809	Glen Kyllachy	1.297708	Sanquhar II	5.115075
Broken Cross	1.384436	Glen Ullinish windfarm	8.962794	Shepherds Rig	0.089438
Chirmorie	1.657364	Glendoe	2.595416	South Humber Bank	-0.229171
Clyde (North)	0.137760	Glenglass	5.923395	Spalding	0.348099
Clyde (South)	0.160720	Gordonbush	-0.114377	St Fergus Mobil	1.319433
Coalburn BESS	0.488649	Griffin Wind	12.573856	Stranoch	2.765717
Corriegarth	3.166722	Hadyard Hill	3.562563	Strathbrora	-0.239253
Corriemoillie	2.054961	Harestanes	2.968802	Strathy Wind	1.359052
Coryton	0.050744	Hartlepool	0.041262	Strathy Wood	3.521899
Creag Riabhach	4.354243	Hopsrig collector	3.143990	Stronelairg	1.389843
Cruachan	2.291529	Invergarry	0.395840	Tangy IV	2.548223
Culligran	2.249748	Kergord	63.624132	Wester Dod	0.453017
Cumberhead Collector	0.906035	Kilgallioch	0.229600	Whitelee	0.137760
Cumberhead West	4.801520	Kilmarnock BESS	0.508195	Whitelee Extension	0.390321
Deanie	3.696014	Kilmorack	0.160696	Yaxley	0.145488
Dersalloch	2.917798	Kype Muir	1.925324		
Dinorwig	3.235969	Lairg South	1.070147		
Dorenell	3.105306	Langage	-0.415421		
Douglas North	0.791681	Limekilns	0.944259		

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 OFTO.

These offshore tariffs have been recalculated in preparation for the RIIO-ET3 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-ET2 tariff setting. The Offshore substation discount has also been updated for the RIIO-ET3 period. Since the Draft forecast, the latest OFTO revenue submissions and updated inflation figures have been incorporated.

Offshore local generation tariffs for projects expected 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	2026/27 Draft Tariff Component (£/kW)			2026/27 Final Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.763294	62.266766	1.546169	11.800544	62.353306	1.548318	0.037250	0.086540	0.002149
Beatrice	10.333497	28.211142	-	10.338561	28.173956	-	0.005064	-0.037186	-
Burbo Bank Extension	15.000200	29.006632	-	15.078754	29.114438	-	0.078554	0.107806	-
Dudgeon	21.825453	34.263951	-	22.039112	34.557346	-	0.213659	0.293395	-
East Anglia 1	13.668366	57.735928	-	13.794649	58.160449	-	0.126283	0.424521	-
Galloper	22.649788	35.752884	-	22.714718	35.821692	-	0.064930	0.068808	-
Greater Gabbard	21.959926	50.882106	-	21.810479	50.495911	-	-0.149447	-0.386195	-
Gunfleet Sands I	25.607715	23.636706	4.417836	25.748620	23.745060	4.438088	0.140905	0.108354	0.020252
Gunfleet Sands II	25.607715	23.636706	4.417836	25.748620	23.745060	4.438088	0.140905	0.108354	0.020252
Gwynt y mor	33.526631	33.007445	-	33.795163	33.246524	-	0.268532	0.239079	-
Hornsea 1A	12.216411	38.285995	-	12.366525	38.668860	-	0.150114	0.382865	-
Hornsea 1B	12.216411	38.285995	-	12.366525	38.668860	-	0.150114	0.382865	-
Hornsea 1C	12.216411	38.285995	-	12.366525	38.668860	-	0.150114	0.382865	-
Hornsea 2A	10.013945	34.349998	-	11.581216	39.257213	-	1.567271	4.907215	-
Hornsea 2B	10.013945	34.349998	-	11.581216	39.257213	-	1.567271	4.907215	-
Hornsea 2C	10.013945	34.349998	-	11.581216	39.257213	-	1.567271	4.907215	-
Humber Gateway	19.297729	44.003831	-	19.350923	44.076959	-	0.053194	0.073128	-
Lincs	22.796279	86.664992	-	22.854684	86.806805	-	0.058405	0.141813	-
London Array	15.035493	51.677448	-	15.064079	51.706203	-	0.028586	0.028755	-
Moray East	12.388999	31.083805	-	12.496093	31.289336	-	0.107094	0.205531	-
Ormonde	36.166486	66.683028	0.531408	36.724993	67.654370	0.539149	0.558507	0.971342	0.007741
Race Bank	13.531499	37.566691	-	13.624728	37.759017	-	0.093229	0.192326	-
Rampion	11.732800	30.556215	-	11.851012	30.795892	-	0.118212	0.239677	-
Robin Rigg	-0.818450	44.785643	14.349035	-0.798686	44.793291	14.351485	0.019764	0.007648	0.002450
Robin Rigg West	-0.818450	44.785643	14.349035	-0.798686	44.793291	14.351485	0.019764	0.007648	0.002450
Seagreen 1	11.818580	21.472235	-	11.825189	21.449883	-	0.006609	-0.022352	-
Sheringham Shoal	34.648241	40.813652	0.887169	34.666415	40.811823	0.887129	0.018174	-0.001829	-0.000040
Thanet	26.640565	49.911157	1.201537	26.589531	49.782470	1.198439	-0.051034	-0.128687	-0.003098
Triton Knoll	10.168392	30.636167	-	11.584709	34.530373	-	1.416317	3.894206	-
Walney 1	31.455493	62.924738	-	31.485699	62.945098	-	0.030206	0.020360	-
Walney 2	32.376940	65.759704	-	32.453015	65.871256	-	0.076075	0.111552	-
Walney 3	14.034741	28.406161	-	14.172132	28.631120	-	0.137391	0.224959	-
Walney 4	14.034741	28.406161	-	14.172132	28.631120	-	0.137391	0.224959	-
West of Duddon Sands	12.070004	60.249830	-	12.191409	60.724975	-	0.121405	0.475145	-
Westermost Rough	24.624576	41.932538	-	24.816259	42.215878	-	0.191683	0.283340	-

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

Table 8 Summary of Demand Tariffs

Non-locational Banded Tariffs	2026/27 Draft	2026/27 Final	Change
Unmetered (p/kWh/annum)	2.587684	2.568147	- 0.019537
Demand Residual (£m)	6,312.8	6,265.2	- 47.7

HH Tariffs (Locational)	2026/27 Draft	2026/27 Final	Change
Average Tariff (£/kW)	2.783829	2.793189	0.009360

EET	2026/27 Draft	2026/27 Final	Change
Average Tariff (£/kW)	3.062913	3.045116	- 0.017797
AGIC (£/kW)	3.158116	3.143391	- 0.014725
Embedded Export Volume (GW)	6.713095	6.713095	-
Total Credit (£m)	20.561626	20.442156	- 0.119470

NHH Tariffs (locational)	2026/27 Draft	2026/27 Final	Change
Average (p/kWh)	0.380904	0.381869	0.000966

Compared to the Draft forecast, both the average HH & NHH demand tariffs have seen an increase. Revenue to be recovered through the demand residual is targeted to be £48m lower than the Draft forecast, this is offset slightly by a small increase to the locational revenue of £0.5m.

The average HH gross tariff is £2.79/kW, an increase of £0.01/kW compared to the Draft Tariff Forecast. The average NHH tariff is 0.38p/kWh, an increase of 0.001p/kWh compared to the Draft forecast.

The forecast Embedded Export Volume for 2026/27 has not changed since the Draft forecast, so remains at 6.71 GW. The total credit paid out to embedded generators (<100 MW) is currently forecast to be £20.44m, a decrease of £119k since Draft Tariffs. The average Embedded Export Tariff (EET) is now £3.05/kW, a decrease of £0.01/kW compared to the Draft forecast.

Table 9 Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	0.153008
7	East Midlands	-	-	2.353700
8	Midlands	2.633945	0.358668	5.777336
9	Eastern	0.063093	0.009140	3.206484
10	South Wales	5.969709	0.739032	9.113100
11	South East	4.368073	0.633420	7.511464
12	London	6.453239	0.700677	9.596630
13	Southern	7.354150	1.008120	10.497541
14	South Western	14.130209	2.071095	17.273600

Demand Residual Tariffs

Since the Draft forecast, we have not updated the site counts or consumption data which are used to allocate the proportion of residual revenue to each charging band. Consumption data uses actual data for October 2024 to September 2025 from the Distribution Network Operators (DNO).

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 demand residual tariffs by band. These tariffs will apply to final demand sites in addition to 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		2026/27 Draft	2026/27 Final	Change
Domestic	Tariff - £/Site/Day	0.224259	0.222566	(0.001693)
LV_NoMIC_1		0.241136	0.239315	(0.001821)
LV_NoMIC_2		0.591767	0.587299	(0.004468)
LV_NoMIC_3		1.251868	1.242416	(0.009452)
LV_NoMIC_4		3.487344	3.461015	(0.026329)
LV1		5.841502	5.797398	(0.044104)
LV2		11.599416	11.511840	(0.087576)
LV3		14.490779	14.381374	(0.109405)
LV4		38.470555	38.180103	(0.290452)
HV1		32.081262	31.839048	(0.242214)
HV2		118.044020	117.152788	(0.891232)
HV3		186.829065	185.418505	(1.410560)
HV4		532.936002	528.912335	(4.023667)
EHV1		327.952592	325.476550	(2.476042)
EHV2		1,168.201395	1,159.381475	(8.819920)
EHV3		2,532.047492	2,512.930533	(19.116959)
EHV4		5,741.736517	5,698.386405	(43.350112)
T-Demand1		1,412.614771	1,401.949529	(10.665242)
T-Demand2		2,953.527974	2,931.228837	(22.299137)
T-Demand3		7,644.127018	7,586.413858	(57.713160)
T-Demand4		20,987.693775	20,829.236682	(158.457093)

Unmetered demand		p/kWh	p/kWh	
Unmetered		2.587684	2.568147	(0.019537)

Demand Residual (£m)		6312.83	6265.17	-47.66

Transmission Demand Residual tariffs have decreased by 0.8% compared to the Draft Tariffs, driven by the reduction in revenue to be collected.

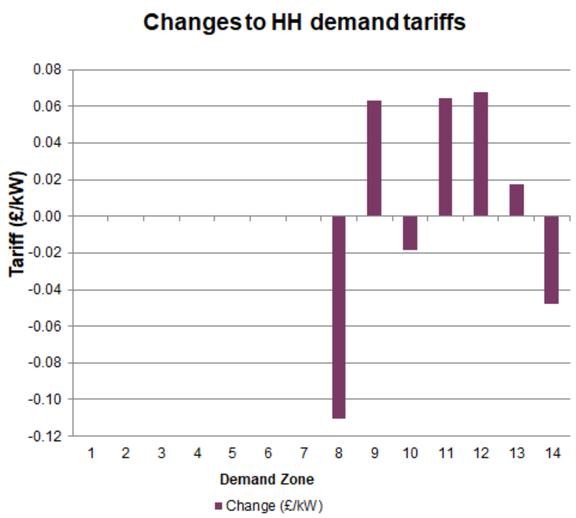
Half-Hourly Demand Tariffs

Table 11 shows the gross HH demand tariffs for 2026/27, compared to the Draft forecast publication.

Table 11 Half-Hourly Demand Tariffs

Zone	Zone Name	2026/27 Draft (£/kW)	2026/27 Final (£/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	2.744697	2.633945	-0.110752
9	Eastern	-	0.063093	0.063093
10	South Wales	5.987934	5.969709	-0.018225
11	South East	4.303795	4.368073	0.064278
12	London	6.385307	6.453239	0.067932
13	Southern	7.336917	7.354150	0.017233
14	South Western	14.178337	14.130209	-0.048128

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 the implementation of CMP463 (Stabilising the Specific Onshore Expansion Factors), changes in Nodal demand and embedded generation forecasts. Zones 1 to 7 are subject to the zero floor on demand tariffs.

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

Where a transmission site is connected at a Grid Supply Point which feeds multiple DNO networks, Demand Tariffs (HH & EET) are derived from the average zonal tariffs from the relevant DNO zones. We have created site specific tariffs for transmission connected users for all GSPs at the boundaries of multiple DNO areas in 2026/27.

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

		DNO 1	DNO 2	DNO 3	DNO 1		DNO 2		DNO 3		T-connected Site			EET T-connected Site			
Site Code	Site Name	Demand Zone	Demand Zone	Demand Zone	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	HH T-Connected Tariff Floored (£/kW)	AGIC £/Kw	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	EET T-Connected Tariff Floored (£/kW)
AMEM	Amersham	9	13	0	1.660538	-1.597445	2.722927	4.631223	0.000000	0.000000	2.191732	1.516889	3.708621	3.143391	2.191732	1.516889	6.852012
AXMI	Axminster	13	14	0	2.722927	4.631223	2.993167	11.137042	0.000000	0.000000	2.858047	7.884132	10.742179	3.143391	2.858047	7.884132	13.885570
BARK	Barking	9	12	0	1.660538	-1.597445	5.004241	1.448998	0.000000	0.000000	3.332389	-0.074223	3.258166	3.143391	3.332389	-0.074223	6.401557
BEDD	Beddington	11	12	0	4.361389	0.006685	5.004241	1.448998	0.000000	0.000000	4.682815	0.727841	5.410656	3.143391	4.682815	0.727841	8.554047
BRIM	Brimsdown	9	12	0	1.660538	-1.597445	5.004241	1.448998	0.000000	0.000000	3.332389	-0.074223	3.258166	3.143391	3.332389	-0.074223	6.401557
CARR	Carrington	4	6	0	-1.832830	-4.386530	-1.994929	-0.995454	0.000000	0.000000	-1.913880	-2.690992	0.000000	3.143391	-1.913880	-2.690992	0.000000
CELL	Cellarhead	6	8	0	-1.994929	-0.995454	-0.725749	3.359694	0.000000	0.000000	-1.360339	1.182120	0.000000	3.143391	-1.360339	1.182120	2.965172
ECLA	East Claydon	7	13	0	-2.095433	1.305742	2.722927	4.631223	0.000000	0.000000	0.313747	2.968482	3.282229	3.143391	0.313747	2.968482	6.425620
GREN	Grendon	9	7	0	1.660538	-1.597445	-2.095433	1.305742	0.000000	0.000000	-0.217448	-0.145851	0.000000	3.143391	-0.217448	-0.145851	2.780092
IROA	Iron Acton	8	10	0	-0.725749	3.359694	-3.101888	9.071597	0.000000	0.000000	-1.913818	6.215645	4.301827	3.143391	-1.913818	6.215645	7.445218
KIBY	Kirkby	6	4	0	-1.994929	-0.995454	-1.832830	-4.386530	0.000000	0.000000	-1.913880	-2.690992	0.000000	3.143391	-1.913880	-2.690992	0.000000
LALE	Laleham	11	13	0	4.361389	0.006685	2.722927	4.631223	0.000000	0.000000	3.542158	2.318954	5.861111	3.143391	3.542158	2.318954	9.004502
LEMR	Lea Marston (was Hams Hall)	7	8	0	-2.095433	1.305742	-0.725749	3.359694	0.000000	0.000000	-1.410591	2.332718	0.922127	3.143391	-1.410591	2.332718	4.065518
LITT	Littlebrook	11	12	0	4.361389	0.006685	5.004241	1.448998	0.000000	0.000000	4.682815	0.727841	5.410656	3.143391	4.682815	0.727841	8.554047
MELK	Melksham	13	14	0	2.722927	4.631223	2.993167	11.137042	0.000000	0.000000	2.858047	7.884132	10.742179	3.143391	2.858047	7.884132	13.885570
WALP	Walpole	7	9	0	-2.095433	1.305742	1.660538	-1.597445	0.000000	0.000000	-0.217448	-0.145851	0.000000	3.143391	-0.217448	-0.145851	2.780092
WISD	Willesden	13	12	0	2.722927	4.631223	5.004241	1.448998	0.000000	0.000000	3.863584	3.040110	6.903694	3.143391	3.863584	3.040110	10.047085

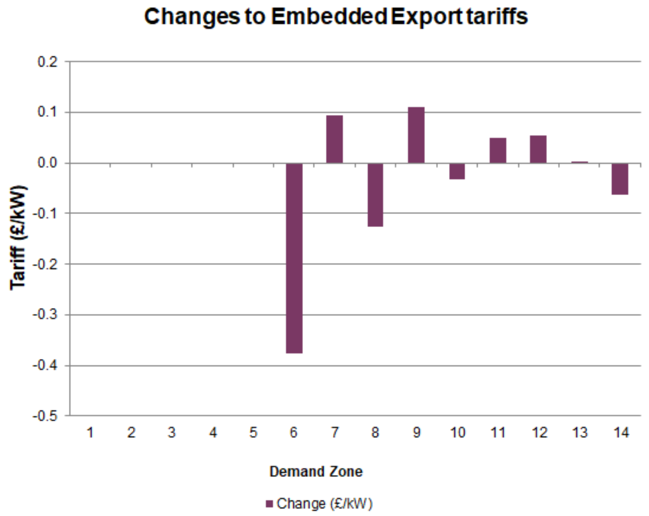
Embedded Export Tariffs (EET)

Table 13 shows the Embedded Export tariffs for 2026/27, compared to the Draft forecast.

Table 13 Embedded Export Tariffs

Zone	Zone Name	2026/27 Draft (£/kW)	2026/27 Final (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.529706	0.153008	-0.376698
7	East Midlands	2.259448	2.353700	0.094252
8	Midlands	5.902813	5.777336	-0.125477
9	Eastern	3.096730	3.206484	0.109754
10	South Wales	9.146050	9.113100	-0.032950
11	South East	7.461911	7.511464	0.049553
12	London	9.543423	9.596630	0.053207
13	Southern	10.495033	10.497541	0.002508
14	South Western	17.336453	17.273600	-0.062853

Figure 3 Embedded export tariff changes



The average EET is £3.05/kW, a decrease of £0.02/kW since the Draft forecast. The Embedded Export Volume is forecast to be 6.71 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 via demand tariffs, which will affect the price of HH and NHH demand residual tariffs.

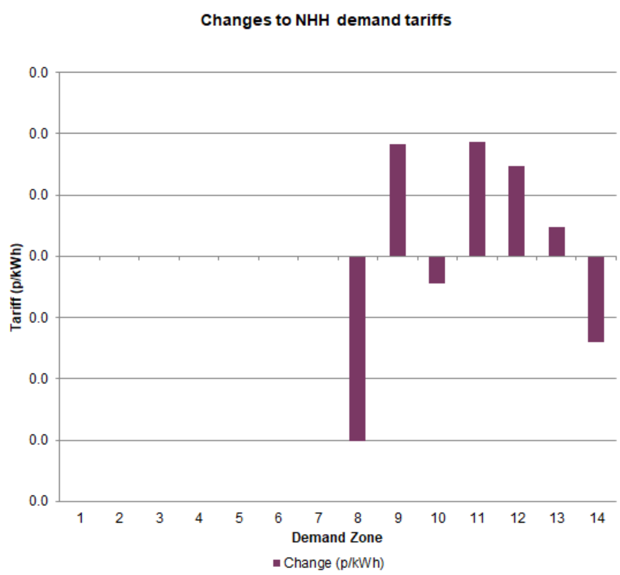
Non-Half-Hourly Demand Tariffs

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

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2026/27 Draft (p/kWh)	2026/27 Final (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	0.373749	0.358668	-0.015081
9	Eastern	-	0.009140	0.009140
10	South Wales	0.741288	0.739032	-0.002256
11	South East	0.624099	0.633420	0.009321
12	London	0.693301	0.700677	0.007376
13	Southern	1.005758	1.008120	0.002362
14	South Western	2.078149	2.071095	-0.007054

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2026/27 is 0.38 p/kWh, a 0.001 p/kWh increase compared to the Draft forecast. As mentioned above for the HH and Embedded tariffs, the locational demand and embedded 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 the Final Tariffs process.

Inputs affecting the locational element of tariffs

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

- Contracted generation;
- Nodal demand and embedded generation
- 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 31 October 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 December Draft Tariffs and January Final Tariffs we 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

	2026/27 Tariffs			
Generation (GW)	**Initial**	**August**	**Draft**	**Final**
Contracted TEC	127.61	125.56	120.14	120.14
Modelled Best View TEC	123.65	111.17	*For input to locational tariffs post 31st October please see Contracted TEC*	
Chargeable TEC	109.99	97.45	102.88	101.64

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 31 October 2025.

Table 16 Interconnectors

Interconnector	Node	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
Auchencrosh	Auchencrosh 275kV	Northern Ireland	10	0	500	0
Britned	Grain 400kV Substation	Netherlands	24	0	1,200	0
East - West	Deeside 400kV Substation	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
IFA2 Interconnector	Chilling 400kV Substation	France	26	0	1,100	0
IFA Interconnector	Sellindge 400kV Substation	France	24	0	1,988	0
LionLink (EuroLink)	Friston 400kV Substation	Netherlands	18	0	1,600	0
Nemo Link	Richborough 400kV Substation	Belgium	24	0	1,020	0
NeuConnect Interconnector	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

Network Model

The network model comprises all onshore transmission substations and circuits. Substations are represented by nodes, and circuits are "links" that connects the nodes to form the onshore transmission network. The network model is based on Electricity Ten Year Statement (ETYS) data, which can be found on NESO's website[9].

In accordance with CUSC 14.15.10, we must use the ETYS network model data including updates up to 31 October 2025. Due to a delay in the next ETYS publication, the network model is still based on the 2024 ETYS data.

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 £19.157575/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

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

[9] neso.energy/publications/electricity-ten-year-statement-etys

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), 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.

The locational onshore security factor has been recalculated ahead of the new price control and is now set at 1.75 for the duration of RIIO-ET3.

Onshore Local Substation Tariffs

Onshore local 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 2026/27 Final Tariff publication, Onshore Local Substation tariffs have been updated based on onshore TO data and Ofgem’s Final RIIO-ET3 Determinations.

Offshore Local Tariffs

Local offshore circuit tariffs, local offshore substation tariffs and ETUoS tariffs are indexed in line with the revenue of the relevant OFTO. These tariffs have been recalculated for the RIIO-ET3 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-ET2 tariff setting.

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 the Onshore TOs (ONTOs), 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 (the upcoming RIIO-ET3 period will run from 2026/27 – 2030/31.) Financial parameters including project spending profiles, rate of return and inflation index are set at the beginning of each price control period. Onshore TO allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process. (AIP).

The Onshore and Offshore TOs provide NESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The 2026/27 revenue forecasts have been based on Onshore and Offshore TOs' final submissions in January 2026.

An overview of revenue to be recovered can be found in Table 17. For more details on the TNUoS revenue breakdown, please refer to Appendix F: Transmission Company Revenues.

Table 17 Allowed Revenues

	2026/27 TNUoS Revenue			
£m Nominal	**Initial Forecast**	**August Forecast**	**December Draft**	**January Final**
TO Income from TNUoS				
National Grid Electricity Transmission	2,590.0	4,053.4	3,287.0	3,287.0
Scottish Power Transmission	899.2	1,186.1	1,077.9	1,082.9
SHE Transmission	1,573.0	2,473.1	2,098.0	2,083.1
Total TO Income from TNUoS	**5,062.2**	**7,712.6**	**6,463.0**	**6,453.0**
Other Income from TNUoS				
Other Pass-through from TNUoS	66.1	69.0	71.3	40.6
Offshore (plus interconnector contribution / allowance)	1,111.3	1,137.3	1,121.3	1,117.1
Total Other Income from TNUoS	**1,177.4**	**1,206.3**	**1,192.6**	**1,157.7**
Total to Collect from TNUoS	**6,239.6**	**8,918.9**	**7,655.6**	**7,610.7**

Please note these figures are rounded to one decimal place.

Generation / Demand (G/D) Split

The G/D split 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 (£7.11m) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is a decrease of £0.81m to local charges associated with pre-existing assets since the Draft forecast.

Table 18 Generation and demand revenue proportions

		2026/27 Tariffs			
Code	Revenue	Initial Forecast	August Forecast	December Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50
y	Error Margin	29.6%	30.3%	30.3%	30.3%
ER	Exchange Rate (€/£)	1.19	1.19	1.19	1.19
MAR	Total Revenue (£m)	6,238.94	8,918.26	7,654.92	7,610.05
GO	Generation Output (TWh)	232.10	199.28	199.28	199.28
G	% of revenue from generation	20.37%	14.24%	16.06%	16.18%
D	% of revenue from demand	79.63%	85.76%	83.94%	83.82%
G.R	Revenue recovered from generation (£m)	1,270.74	1,269.63	1,229.37	1,231.67
D.R	Revenue recovered from demand (£m)	4,968.20	7,648.62	6,425.54	6,378.38
Breakdown of generation revenue					
	Revenue from the Peak element	170.67	133.61	154.03	150.54
	Revenue from the Year Round Shared element	191.75	197.55	232.69	210.77
	Revenue from the Year Round Not Shared element	141.65	169.58	195.57	174.51
	Revenue from Onshore Local Circuit tariffs	50.94	62.28	60.24	49.53
	Revenue from Onshore Local Substation tariffs	17.64	29.14	29.45	28.95
	Revenue from Offshore Local tariffs	867.57	894.94	856.43	869.12
	Revenue from the adjustment element	-169.49	-217.46	-299.02	-251.75
G.MAR	Total Revenue recovered from generation (£m)	1,270.74	1,269.63	1,229.37	1,231.67
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	7.97	7.90	7.92	7.11

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 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[10]. This figure is finalised, as per OBR's March EFO, at €1.192525/£.

Generation Output

The forecast output of generation is 199.3 TWh and was finalised in the Five-Year View. This figure is the average of the Future Energy Scenarios in the 2025 Future Energy Scenarios (FES).

Error Margin

The error margin for 2026/27 tariffs was updated and finalised in the Five-Year View, following publication of the outturn of 2024/25 data. This is derived from historical data in the past five whole years (thus for year 2026/27, we use data from years 2020/21 – 2024/25).

[10] obr.uk/docs/dlm_uploads/OBR_Economic_and_fiscal_outlook_March_2025.pdf

Table 19 Generation revenue error margin calculation

Data from year:	Calculation for Revenue inputs: Revenue variance	Adjusted variance	Generation output variance
2020/21	-13.2%	-13.2%	7.5%
2021/22	4.3%	4.3%	9.5%
2022/23	9.5%	9.5%	13.1%
2023/24	-1.7%	-1.7%	-3.5%
2024/25	0.9%	1.0%	-7.0%
Systemic error:	0.0%		
Adjusted error:		13.2%	13.1%
Error margin =			30.3%

Onshore local charges associated with Pre-existing assets

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

The onshore local circuit tariff reflects the impact of the generator on its local network (before reaching the MITS – Main Interconnected Transmission System). If some of the circuits in the local network existed prior to the generator 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 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)
Aberarder Wind Farm	£ 0.791681
Aberdeen Offshore Wind Farm	£ -
A'Chruach Wind Farm	£ -
Afton Wind Farm	£ -
Aikengall II Windfarm	£ -
Aikengall IIa Wind Farm	£ -
Alcemi Coalburn Battery Energy Storage Facility	£ -
Arecleoch Windfarm Extension	£ 1.065692
Beinneun Wind Farm	£ 0.061555
Benbrack wind farm	£ 0.453017
Bhlaraidh Wind Farm	£ -
Blacklaw	£ -
Blacklaw Extension	£ -
Broken Cross Windfarm	£ -
Builth Wells	£ -
Carraig Gheal Wind Farm	£ 5.576776
Chirmorie Wind Farm	£ 1.597988
Clyde North	£ -
Clyde South	£ -
Corriegarth	£ -
Coryton ENERGY	£ -
Crossdykes	£ -
Cruachan	£ -
Cumberhead	£ -
Cumberhead West Wind Farm	£ -
Dalquhandy Wind Farm	£ -
Dealanach WLC WF	£ -
Dersalloch Wind Farm	£ -
Dinorwig	£ -
Dorenell Windfarm	£ -
Douglas West	£ 0.791681
Douglas West Extension	£ -
Edinbane Windfarm	£ -
Enoch Hill	£ -
Ewe Hill	£ -
Fallago Rig Wind Farm	£ -
Ffestiniog	£ -

Project Name	Pre-existing local circuit tariff (£/kW)
Foyers	£ -
Galawhistle Wind Farm	£ -
Glen App Windfarm	£ -
Glen Kyllachy Wind Farm	£ -
Harting Rig Wind Farm	£ -
Hartlepool	£ -
Hunterston Energy Storage Facility	£ -
Kennoxhead Wind Farm Extension	£ 2.747132
Kilmarnock BESS	£ -
Kincardine Battery Storage Facility	£ -
Kype Muir	£ -
Lairg II Wind Farm	£ -
Limekiln	£ -
Lochluichart	£ -
Marchwood	£ -
Middle Muir Wind Farm	£ -
Pen Y Cymoedd Wind Farm	£ -
Pencloe Windfarm	£ -
Rocksavage	£ -
Saltend	£ -
Sandy Knowe Wind Farm	£ -
Sanquhar II Wind Farm	£ 3.384797
Sanquhar Wind Farm	£ 0.926957
Shepherds Rig Wind Farm	-£ 0.110462
Spalding	£ -
Stranoch Wind Farm	£ 1.597988
Strathy Wood	£ -
Stronelairg	£ 0.257300
Tangy IV WF	£ -
Twentyshilling Wind Farm	£ -
Viking Wind Farm	£ 0.001625
Whitelee Extension	£ -
Whiteside Hill Wind Farm	£ -
Windy Rig Wind Farm	£ -
Windy Standard II (Brockloch Rig) Wind Farm	£ -
Windy Standard III Wind Farm	£ -

Aggregated pre-existing TEC (MW)	15,320

Onshore local substation tariffs reflect the cost of accommodating the generator at 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 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	0.406178	37.20
Toddleburn Wind Farm	0.406178	

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 101.64 GW, which is a decrease of 1.24 GW since the Draft forecast. 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 have used the contracted TEC position as of 31 October 2025 to set locational tariffs in the Transport model. Our best view has been used to set the adjustment tariff in the Tariff model.

Demand

Our forecasts of chargeable HH demand, NHH demand and embedded generation for 2026/27 have not been updated since the Draft Tariff forecast.

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
- 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[11] for a detailed breakdown of the demand charging bases.

Table 22 Charging Bases

	2026/27 Tariffs			
Charging Bases	Initial	August	Draft	Final
Generation (GW)	109.99	97.45	102.88	101.64
NHH Demand (4pm-7pm TWh)	23.03	22.95	22.77	22.77
Gross charging				
Total Average Gross Triad (GW)	47.55	47.54	47.54	47.54
HH Demand Average Gross Triad (GW)	16.67	16.69	16.71	16.71
Embedded Generation Export (GW)	6.84	7.08	6.71	6.71

Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For final tariff publication, we have used the final version of the 2026/27 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[12].

[11] Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.
[12] neso.energy/document/376351/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

		2026/27 Tariffs			
Component		Initial	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	20.37%	14.24%	16.06%	16.18%
D	Proportion of revenue recovered from demand (%)	79.63%	85.76%	83.94%	83.82%
R	Total TNUoS revenue (£m)	6,238.94	8,918.26	7,654.92	7,610.05
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	504.07	500.74	582.28	535.82
O	Revenue recovered from offshore local tariffs (£m)	867.57	894.94	856.43	869.12
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.64	29.14	29.45	28.95
S_G	Revenue recovered from onshore local circuit tariffs (£m)	50.94	62.28	60.24	49.53
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	7.97	7.90	7.92	7.11
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50
	Error Margin	29.6%	30.3%	30.3%	30.3%
	Exchange Rate (€/£)	1.19	1.19	1.19	1.19
	Total generation Output (TWh)	232.10	199.28	199.28	199.28
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	342.55	291.18	291.18	291.18
	Adjustment Revenue (£m)	(169.49)	(217.46)	(299.02)	(251.75)
BG	Generator charging base (GW)	109.99	97.45	102.88	101.64
AdjTariff	Generator adjusment tariff (£/kW)	(1.54)	(2.23)	(2.91)	(2.48)
Gross demand residual					
R_D	Demand residual (£m)	4,832.9	7,520.8	6,312.8	6,265.2
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	158.00	152.22	133.28	133.65
EE	Amount to be paid to Embedded Export Tariffs (£m)	-22.73	-24.43	-20.56	-20.44
B_D	Demand Gross charging base (GW)	47.55	47.54	47.54	47.54

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 publication 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 Final 2026/2027 Tariffs on Thursday 12 February. 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/376341/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@neso.energy

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 per 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.

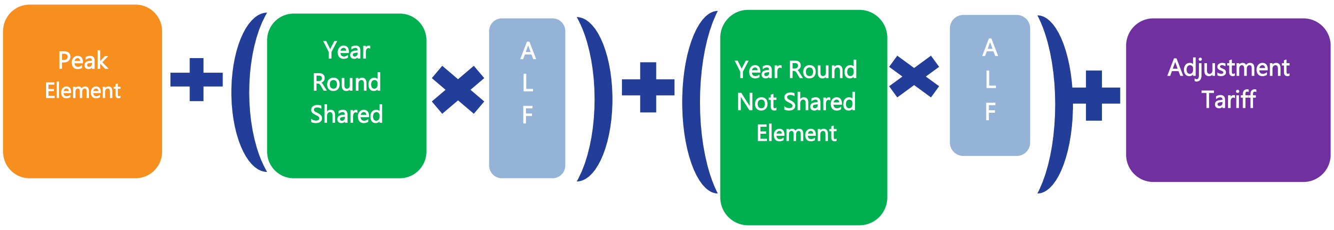
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

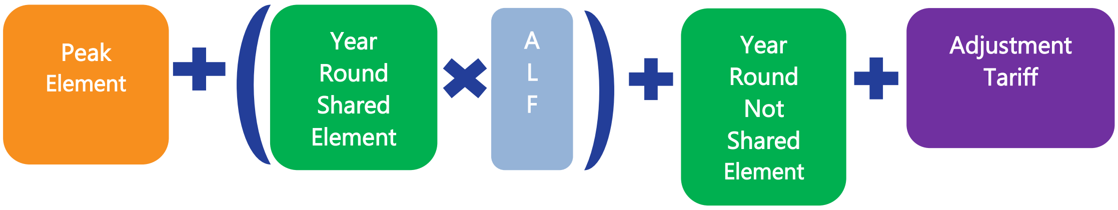
Conventional Carbon Generators

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



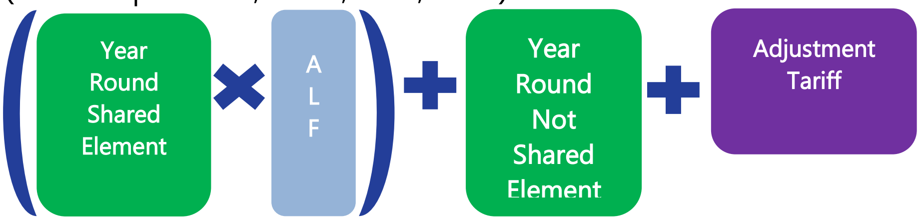
Conventional Low Carbon Generators

(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[13] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[14] 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). As an example, 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:

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

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

[14] 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[15]. 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[16].

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).

[15] neso.energy/industry-information/charging/tnuos-charges#Triads-data
[16] 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[17].

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.

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

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which were implemented in the TNUoS tariffs for financial year 2025/26.

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

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

Only one modification which affects 2026/27 TNUoS tariffs has been approved, a summary is shown below:

Table 24 Summary of concluded CUSC modification proposals

Modification directed for implementation:			
Name	**Title**	**Effect of proposed change**	**Implementation**
CMP463	Stabilising the Specific Onshore Expansion Factors from 1 April 2026	Holds Specific Expansion Factors at 2025/26 levels.	1 April 2026

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 forecast and final tariffs.

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		2026/27 Draft		2026/27 Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.615112	-41.745256	-2.490073	-37.248832	0.125039	4.496424
2	Southern Scotland	-3.005863	-28.320832	-2.966429	-24.811726	0.039434	3.509107
3	Northern	-5.089515	-10.693203	-5.043729	-9.661553	0.045785	1.031650
4	North West	-1.858954	-4.664982	-1.832830	-4.386530	0.026124	0.278452
5	Yorkshire	-4.129660	-2.223008	-4.090189	-1.947045	0.039471	0.275963
6	N Wales & Mersey	-2.021732	-0.606678	-1.994929	-0.995454	0.026803	-0.388776
7	East Midlands	-2.123360	1.224693	-2.095433	1.305742	0.027927	0.081049
8	Midlands	-0.745649	3.490346	-0.725749	3.359694	0.019900	-0.130652
9	Eastern	1.654048	-1.715433	1.660538	-1.597445	0.006490	0.117989
10	South Wales	-3.135482	9.123416	-3.101888	9.071597	0.033594	-0.051819
11	South East	4.370368	-0.066573	4.361389	0.006685	-0.008980	0.073257
12	London	5.016878	1.368429	5.004241	1.448998	-0.012637	0.080569
13	Southern	2.722574	4.614342	2.722927	4.631223	0.000353	0.016880
14	South Western	2.994385	11.183952	2.993167	11.137042	-0.001218	-0.046910

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

Demand Zone		2026/27 Draft		2026/27 Final		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-44.360368	3.158116	-39.738905	3.143391	4.621463	-0.014725
2	Southern Scotland	-31.326695	3.158116	-27.778155	3.143391	3.548540	-0.014725
3	Northern	-15.782718	3.158116	-14.705283	3.143391	1.077435	-0.014725
4	North West	-6.523937	3.158116	-6.219360	3.143391	0.304576	-0.014725
5	Yorkshire	-6.352669	3.158116	-6.037234	3.143391	0.315434	-0.014725
6	N Wales & Mersey	-2.628410	3.158116	-2.990383	3.143391	-0.361973	-0.014725
7	East Midlands	-0.898668	3.158116	-0.789691	3.143391	0.108977	-0.014725
8	Midlands	2.744697	3.158116	2.633945	3.143391	-0.110752	-0.014725
9	Eastern	-0.061386	3.158116	0.063093	3.143391	0.124479	-0.014725
10	South Wales	5.987934	3.158116	5.969709	3.143391	-0.018225	-0.014725
11	South East	4.303795	3.158116	4.368073	3.143391	0.064278	-0.014725
12	London	6.385307	3.158116	6.453239	3.143391	0.067932	-0.014725
13	Southern	7.336917	3.158116	7.354150	3.143391	0.017233	-0.014725
14	South Western	14.178337	3.158116	14.130209	3.143391	-0.048128	-0.014725

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 publication, we have used the final version of the 2026/27 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2020/21 to 2024/25. Generators which commissioned after 1 April 2022 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 2026/27 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 have been published in the following places:

- Final Annual Load Factors for 2026/27 TNUoS Tariffs: neso.energy/document/376346/download
- Specific ALFs in excel format: neso.energy/document/376351/download

Generic ALFs

Table 27 Generic ALFs

Technology	Generic ALF
Battery	8.0542%
Biomass	40.0724%
CCGT_CHP	41.5400%
Coal	7.5610%
Gas_Oil	6.9166%
Hydro	37.1713%
Nuclear	60.9910%
Offshore_Wind	47.1080%
Onshore_Wind	39.6831%
Pumped_Storage	10.9859%
Reactive_Compensation	0.0000%
Solar	16.8358%
Tidal	14.1000%
Wave	2.9000%

Please note: ALF figures for Wave and Tidal 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) was 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 have been made since the Draft forecast.

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
There have been no contracted generation changes since the Draft Forecast			

Appendix F: Transmission Company Revenues

Transmission Owner revenue forecasts

The revenue forecast has been based on final data submissions received from Onshore and Offshore TOs in January 2026. 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 TOs (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 the money through 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.

Since the Draft forecast, there has been a net decrease in ONTO allowed revenues and decreases in the adjustment term and other passthrough items. This has been offset by an increase in the OFTO allowed revenues.

Table 29 NESO revenue breakdown

Term £m nominal	NESO TNUoS Other Pass-Through Initial Forecast	August Forecast	December Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.67	0.67	0.67	0.67
Network Innovation Competition Fund (NICFt)	0.00	0.00	0.00	0.00
Strategic Innovation Fund (SIFt)	62.90	62.90	62.90	46.93
The Adjustment Term (ADJt)	27.02	20.59	22.79	8.00
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap & Floor Revenue Adjustment (TICFt)	1,111.27	1,137.31	1,121.27	1,117.14
Interconnectors Payment Term (ICPt)	-71.88	-71.88	-71.88	-71.88
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00
NGET revenue pass-through (NGETTOt)*	2,590.04	4,053.45	3,287.05	3,287.05
SPT revenue pass-through (TSPt)	899.17	1,186.05	1,077.93	1,082.88
SHETL revenue pass-through (TSHt)	1,573.04	2,473.14	2,098.02	2,083.09
NESO Bad debt (BDt)	0.03	-0.31	0.00	0.00
NESO other pass-through items (LFt + ITCt etc)	47.35	57.00	56.84	56.84
NESO legacy adjustment (LARt)	0.00	0.00	0.00	0.00
Total	**6,239.61**	**8,918.93**	**7,655.59**	**7,610.72**

Onshore TOs (NGET, SPT and SHET) revenue forecast

The allowed revenue forecast for the three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) was provided to us in January 2026, as required by STCP24-1. Total ONTO revenue is forecast to be £6,453.02m, a £9.97m decrease since the Draft forecast. (NGET, £0.00, SPT +£4.95m, SHET -£14.93m).

NGET allowed revenue is forecast in line with the allowed revenue as published in the RIIO-ET3 Final Determinations PCFM[18,19].

SHET allowed revenue reflects the latest figures set out in Ofgem's Final Determination PCFM published on 16 December 2025, in addition to known updates discussed and approved by Ofgem since the date of the Final Determinations publication and reflects the latest OBR inflationary increases and cost of debt updates.

SPT allowed revenue forecasts reflects the RIIO-ET3 final determination, with post final determination adjustments agreed with Ofgem.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2026/27 is forecast to be £1.14bn, an increase of £14.3m since the Draft Forecast. Revenues have been

[18]Revised 16 December in their Statutory Consultation on the RIIO-3 Licence Drafting Modifications

[19] ofgem.gov.uk/consultation/modifications-riio-3-licences-and-associated-documents

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 £130.4m of forecast revenue (11% 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 2026.

Table 30 NGET allowed revenue breakdown

Transmission Revenue Forecast			**National Grid Electricity Transmission**			
All monies £m (nominal) unless stated otherwise			**Initial Forecast**	**August Forecast**	**December 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	4.13%	-	-	-
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 Environme	C6	$LEDR_t$	0.00	-	-	-
Close out of the RIIO-ET1 Incentive in respect of the sulphur he	C7	$LSFI_t$	0.00	-	-	-
Close out of the RIIO-ET1 reliability incentive in respect of ener	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						
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**2,590.04**	**4,053.00**	**3,287.05**	**3,287.05**

Notes:

- All monies are nominal 'money of the day' prices unless stated otherwise.
- Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders
- Initial forecast was as per the January 2025 STCP 24-1 submission
- August forecast was as per the RIIO-ET3 Draft Determinations PCFM
- December Draft forecast reflected the latest figures set out in Ofgem’s Final Determination PCFM published on 16 December 2025
- January Final reflects the January 2026 STCP 24-1 submission

Table 31 SPT allowed revenue breakdown

Transmission Revenue Forecast			**Scottish Power Transmission**			
All monies £m (nominal) unless stated otherwise			**Initial Forecast**	**August Forecast**	**December Draft**	**January Final**
Inflation 2018/19		$PI_{2018/19}$	283.31	–	–	352.84
Inflation		PI_t	380.53	–	–	386.56
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	669.45	–	–	978.55
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	–	–	0.00
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**899.17**			**1,072.08**
SONIA	B1	It-1	–			
Allowed Revenue	B2	AR_{t-1}	–			
Recovered Revenue	B4	RR_{t-1}	–			
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**			**0.00**
Legacy pass-through	C1	LP_t	0.00	–	–	0.00
Legacy MOD	C2	$LMOD_t$	0.00	–	–	5.84
Legacy K correction	C3	LK_t	0.00	–	–	4.97
Legacy TRU term	C4	$LTRU_t$	0.00	–	–	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	–	–	0.00
Close out of the RIIO-1 adjustment in respect of the Environme	C6	$LEDR_t$	0.00	–	–	0.00
Close out of the RIIO-ET1 Incentive in respect of the sulphur he	C7	$LSFI_t$	0.00	–	–	0.00
Close out of the RIIO-ET1 reliability incentive in respect of ener	C8	LRI_t	0.00	–	–	0.00
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	0.00	–	–	0.00
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**0.00**			**10.80**
Site Rental Charges						
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**899.17**	**1,186.05**	**1,077.93**	**1,082.88**

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Notes:

- All monies are nominal 'money of the day' prices unless stated otherwise.
- Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders

- Initial forecast was as per the January 2025 STCP 24-1 submission
- August forecast was as per the RIIO-ET3 Draft Determinations PCFM
- December Draft forecast reflected the latest figures set out in Ofgem's Final Determination PCFM published on 16 December 2025
- January Final reflects the January 2026 STCP 24-1 submission

Table 32 SHET allowed revenue breakdown

Transmission Revenue Forecast All monies £m (nominal) unless stated otherwise			SHE Transmission Initial Forecast	 August Forecast	 December Draft	 January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	-	-	283.31
Inflation		PI_t	380.53	-	-	386.56
Opening Base Revenue Allowance (2018/19 prices)	A1	R_t	1,171.15	-	-	1,514.74
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	-	-	0.00
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**1,573.04**	**-**	**-**	**2,066.77**
SONIA	B1	It-1	4.13%	-	-	4.03%
Allowed Revenue	B2	AR_{t-1}	1,191.62	-	-	1,183.42
Recovered Revenue	B4	RR_{t-1}	1,191.62	-	-	1,191.62
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**-**	**-**	**-8.62**
Legacy pass-through	C1	LP_t	0.00	-	-	0.00
Legacy MOD	C2	$LMOD_t$	0.00	-	-	24.94
Legacy K correction	C3	LK_t	0.00	-	-	0.00
Legacy TRU term	C4	$LTRU_t$	0.00	-	-	0.00
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	$LSSO_t$	0.00	-	-	0.00
Close out of the RIIO-1 adjustment in respect of the Environme	C6	$LEDR_t$	0.00	-	-	0.00
Close out of the RIIO-ET1 Incentive in respect of the sulphur he	C7	$LSFI_t$	0.00	-	-	0.00
Close out of the RIIO-ET1 reliability incentive in respect of ener	C8	LRI_t	0.00	-	-	0.00
Close out of RIIO-1 Network Outputs	C9	$NOCO_t$	0.00	-	-	0.00
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**0.00**	**-**	**-**	**24.94**
Site Rental Charges						
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**1,573.04**	**2,473.14**	**2,098.02**	**2,083.09**

Notes

- All monies are nominal 'money of the day' prices unless stated otherwise.
- Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders
- Initial forecast was as per the January 2025 STCP 24-1 submission
- August forecast was as per the RIIO-ET3 Draft Determinations PCFM
- December Draft forecast reflected the latest figures set out in Ofgem’s Final Determination PCFM published on 16 December 2025
- January Final reflects the January 2026 STCP 24-1 submission

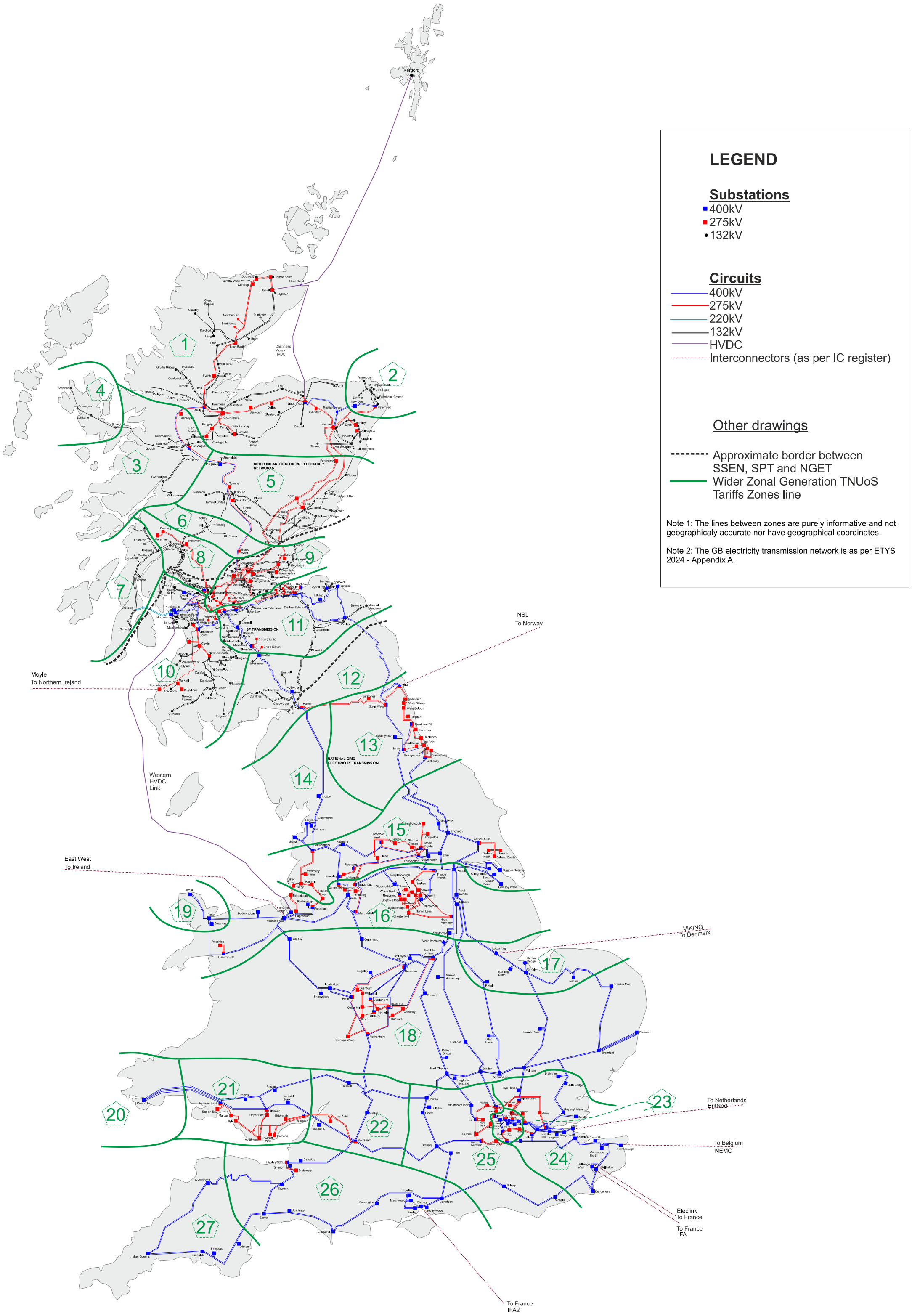
Table 33 Offshore Revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="6">Year</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2021/22</th><th>2022/23</th><th>2023/24</th><th>2024/25</th><th>2025/26</th><th>2026/27</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>6.7</td><td>7.0</td><td>7.8</td><td>8.5</td><td>8.8</td><td>9.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>8.4</td><td>8.7</td><td>9.7</td><td>10.7</td><td>11.1</td><td>11.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>15.3</td><td>15.6</td><td>17.8</td><td>19.4</td><td>20.3</td><td>21.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>9.4</td><td>9.8</td><td>10.9</td><td>12.0</td><td>12.4</td><td>12.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>15.1</td><td>16.3</td><td>18.3</td><td>20.0</td><td>20.9</td><td>21.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>23.4</td><td>24.2</td><td>26.7</td><td>29.5</td><td>30.0</td><td>32.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>14.1</td><td>14.7</td><td>16.2</td><td>17.9</td><td>18.6</td><td>19.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>32.1</td><td>33.2</td><td>37.0</td><td>38.8</td><td>41.6</td><td>43.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>44.7</td><td>46.8</td><td>52.6</td><td>57.3</td><td>59.1</td><td>61.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td>20.8</td><td>21.6</td><td>24.0</td><td>26.3</td><td>27.4</td><td>28.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>30.0</td><td>32.5</td><td>34.0</td><td>40.9</td><td>40.1</td><td>42.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>32.9</td><td>39.8</td><td>37.6</td><td>37.4</td><td>78.8</td><td>75.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td>25.3</td><td>25.5</td><td>28.5</td><td>30.3</td><td>32.3</td><td>33.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>14.4</td><td>13.3</td><td>15.0</td><td>16.6</td><td>17.4</td><td>17.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>14.1</td><td>14.7</td><td>16.5</td><td>18.0</td><td>18.6</td><td>19.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank Extension</td><td>14.1</td><td>14.7</td><td>16.4</td><td>17.7</td><td>18.4</td><td>19.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td>19.6</td><td>20.8</td><td>22.6</td><td>24.9</td><td>26.2</td><td>27.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Race Bank</td><td>27.4</td><td>28.9</td><td>32.5</td><td>35.4</td><td>36.5</td><td>38.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Galloper</td><td>17.1</td><td>17.8</td><td>20.1</td><td>21.9</td><td>22.5</td><td>23.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 3</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>17.8</td><td>18.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 4</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>17.8</td><td>18.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1A</td><td rowspan="5">137.1</td><td>18.4</td><td>20.6</td><td>22.2</td><td>22.9</td><td>24.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1B</td><td>18.4</td><td>20.6</td><td>22.2</td><td>22.9</td><td>24.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1C</td><td>18.4</td><td>20.6</td><td>22.2</td><td>22.9</td><td>24.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Beatrice</td><td>21.1</td><td>24.4</td><td>25.7</td><td>26.5</td><td>28.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Rampion</td><td>15.5</td><td>17.4</td><td>19.7</td><td>20.3</td><td>21.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>East Anglia 1</td><td></td><td rowspan="7">68.3</td><td>47.4</td><td>51.8</td><td>54.8</td><td>57.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2A</td><td></td><td rowspan="6">138.7</td><td>25.3</td><td>27.3</td><td>28.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2B</td><td></td><td>25.3</td><td>27.3</td><td>28.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2C</td><td></td><td>25.3</td><td>27.3</td><td>28.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Triton Knoll</td><td></td><td>41.3</td><td>42.7</td><td>46.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Moray East</td><td></td><td>28.2</td><td>50.0</td><td>52.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Seagreen 1</td><td></td><td rowspan="2">52.6</td><td rowspan="2">89.6</td><td>44.5</td><td>Draft revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2025/26</td><td></td><td></td><td></td><td>0.0</td><td>NESO Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2026/27</td><td></td><td></td><td></td><td></td><td></td><td>130.4</td><td>NESO Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through</td><td>549.0</td><td>594.3</td><td>765.6</td><td>879.8</td><td>1,010.9</td><td>1,135.5</td><td></td></tr>
</table>

Notes:

- 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.
- Network Innovation Competition (NIC) & Strategic Innovation Fund (SIF) payments are not included as they do not form part of OFTO Revenue.
- All monies are nominal 'money of the day' prices unless stated otherwise.

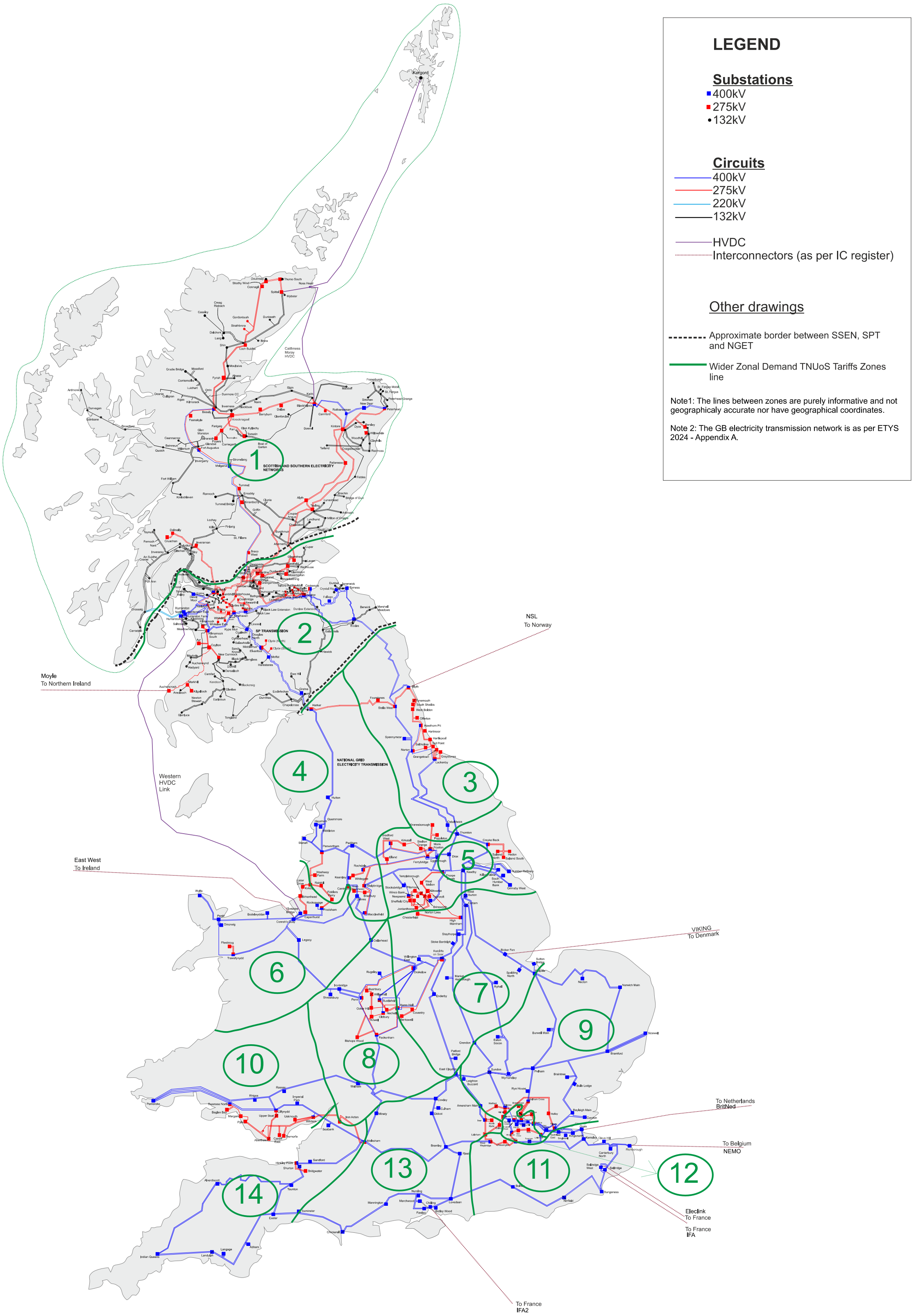
Appendix G: Generation Zones Map



Geographical map as of 1 April 2025

Please note that this map has been redrawn to show the existing zones on a higher quality, more recent ETYS map; it does not represent a re-zoning exercise. For the most up to date maps, please refer to Electricity Ten Year Statement 2024 Appendix A.

Appendix H: Demand Zones Map



Geographical map as of 1 April 2025

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 December 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	Week 24 Finalised
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	Inflation	Forecast			Actual
RESIDUAL / ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	From OFTOs & NESO best view
	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From 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 January 2026	Publication of Final TNUoS Tariffs for 2026/27

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