

April 2026

Initial TNUoS Tariffs for 2027/28

National Energy System Operator



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Executive Summary





Executive Summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland, and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Initial forecast of TNUoS Tariffs for 2027/28.

Under the National Energy System Operator's (NESO) Electricity System Operator Licence condition E10 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2027/28 on our website¹.

These tariffs will take effect from 1 April 2027, they have no impact on charging year 2026/27.

Total revenues to be recovered

The total TNUoS revenue to be collected for 2027/28 is forecast to be £9.11bn, an increase of £1.50bn compared to 2026/27. There has been an increase of £1.58bn in the allowed revenue for the Onshore Transmission Owners (ONTOs) based on their January revenue submission as per STCP24-1. In addition, there has also been a £108m increase in the forecast allowed revenues for Offshore Transmission Owners (OFTOs), and a net decrease of £182m in other passthrough items.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.39bn for 2027/28, an increase of £154m since 2026/27. This is primarily driven by an

increase in expected revenue from offshore local tariffs.

The generation charging base has been updated to 121.8 GW based on our best view on generation projects for 2027/28, this view will be further refined throughout the year. The average generation tariff is forecast to be £11.38/kW, a decrease of £0.74/kW since 2026/27 due to the increase in the expected charging base outweighing the increase in generation revenue to be collected.

Demand tariffs

Revenue to be collected from demand users is forecast to be £7.73bn for 2027/28, a £1.35bn increase compared to 2026/27. The increase in demand revenue is the result of the increase in total TNUoS revenue to be collected.

The TNUoS cost for an average domestic household is £96.85 in 2027/28, accounting for 11.1% of a typical annual electricity bill. This is an increase of £13.61 compared to 2026/27, but is £7.70 lower than the equivalent 2027/28 cost in the September 2025 Five-Year View.

In 2027/28, it is forecast that £25.74m would be payable to embedded generators (<100 MW) through the

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



Embedded Export Tariff (EET), an increase of £5.3m compared to 2026/27. This is due to an increase in the forecast Embedded Export Volume to 7.65GW. The average EET is £3.37/kW, which is an increase of £0.32/kW since 2026/27.

The average gross HH demand tariff for 2027/28 is £3.48/kW, an increase of £0.69/kW compared to 2026/27. The average NHH demand tariff is 0.48p/kWh, an increase of 0.10p/kWh since 2026/27.

Next TNUoS tariff publication

The timetable of TNUoS tariff forecasts for 2027/28 is available on our website².

Our next TNUoS tariff publication will be our Five-Year View of 2027/28 – 2031/32 tariffs & Projection of additional years, which will be published in September 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](https://www.neso.energy/document/376486/download)

Charging Methodology Changes





This Report

This report contains the initial forecast of TNUoS tariffs for the charging year 2027/28.

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

This section summarises any key changes to the methodology.

Charging Methodology Changes

No changes have been approved to the charging methodology since we published the Final Tariffs for 2026/27 and consequently no additional changes have been incorporated in this forecast.

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

Reformed National Pricing programme and electricity network charging

REMA has concluded and in July 2025, Ofgem published an open letter³ outlining their initial thinking on reforming network charging signals to align with the UK Government's decision to retain a single GB-wide electricity market⁴.

Please note that this ongoing work has not been included in this forecast and details of any CUSC modifications that may impact 2027/28 tariffs can be found in Appendix B.

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.

Please note that this ongoing work has not been included in this forecast and details of any CUSC modifications that may impact 2027/28 tariffs can be found in Appendix B.

³ [ofgem.gov.uk/sites/default/files/2025-07/open-letter-reforming-network-charging-signals.pdf](https://www.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-rem-a-summer-update-2025/review-of-electricity-market-arrangements-rem-a-summer-update-2025-accessible-webpage](https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rem-a-summer-update-2025/review-of-electricity-market-arrangements-rem-a-summer-update-2025-accessible-webpage)

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 2027/28 and how these tariffs were calculated.

Table 1 Summary of Generation Tariffs

Generation Tariffs (£/kW)	2026/27 Final	2027/28 April	Change
Adjustment	- 2.476760	- 2.114050	0.362710
Average Generation Tariff*	12.117642	11.376179	- 0.741463

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

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

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

Average generation tariffs have decreased by £0.74/kW, due to the increase in generation the generation charging base outweighing the increase in generation revenue to be collected, compared to 2026/27. The generation adjustment has increased by £0.36/kW, decreasing in magnitude, to become less negative; this is because the expected increase in revenue to be collected from wider tariffs is outweighed by the expected increase 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 2027/28. 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

Example tariffs for a generator of each technology type

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)					
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)					
1	North Scotland	3.441861	33.683697	14.895360	-	2.114050	20.759434	41.485944	27.938974				
2	East Aberdeenshire	5.553769	20.896191	14.895360	-	2.114050	17.756339	34.007222	22.184596				
3	Western Highlands	2.926897	31.284627	13.230397	-	2.114050	18.618857	37.506714	25.194429				
4	Skye and Lochalsh	2.892694	31.284627	20.919587	-	2.114050	21.660330	45.161701	32.883619				
5	Eastern Grampian and Tayside	6.550097	26.714048	9.198452	-	2.114050	18.801047	33.670035	19.105724				
6	Central Grampian	6.055802	26.624790	9.082246	-	2.114050	18.224566	32.992591	18.949352				
7	Argyll	6.466411	24.911931	16.544674	-	2.114050	20.935003	39.580983	25.640993				
8	The Trossachs	4.439447	24.911931	6.825636	-	2.114050	15.020424	27.834981	15.921955				
9	Stirlingshire and Fife	3.433287	23.884596	5.913270	-	2.114050	13.238383	25.145954	14.547288				
10	South West Scotlands	3.406784	24.352139	6.128193	-	2.114050	13.484867	25.685031	14.972606				
11	Lothian and Borders	3.574941	24.352139	2.384851	-	2.114050	10.247806	17.340144	6.459562				
12	Solway and Cheviot	3.208845	12.982367	3.527639	-	2.114050	7.698797	14.359209	7.255654				
13	North East England	4.696149	8.116585	2.157852	-	2.114050	6.691874	10.827390	3.696265				
14	North Lancashire and The Lakes	2.504069	8.116585	1.567869	-	2.114050	3.009505	4.909589	0.029456				
15	South Lancashire, Yorkshire and Humbers	5.070172	1.975235	0.046512	-	2.114050	3.764821	4.484060	1.178682				
16	North Midlands and North Wales	3.467452	0.447231	-	-	2.114050	1.532294	1.688825	1.912796				
17	South Lincolnshire and North Norfolk	-	0.478078	2.593352	-	2.114050	-	1.554787	-	0.647114	0.947042		
18	Mid Wales and The Midlands	0.106757	3.492650	-	-	2.114050	-	0.610233	0.612195	0.542358			
19	Anglesey and Snowdon	5.093612	0.132073	-	-	2.114050	-	3.032391	3.078617	2.054617			
20	Pembrokeshire	7.648204	-	9.075338	-	2.114050	-	1.904019	-	1.272350	6.197952		
21	South Wales & Gloucester	2.535959	-	10.141804	-	2.114050	-	3.634813	-	7.184444	6.677862		
22	Cotswold	0.331177	4.034072	-	13.635240	-	2.114050	-	5.623340	-	12.392559	13.933958	
23	Central London	-	4.594388	4.034072	-	6.484866	-	2.114050	-	7.688756	-	10.167750	6.783584
24	Essex and Kent	-	3.927791	4.034072	-	-	-	2.114050	-	4.428212	-	3.016287	0.298718
25	Oxfordshire, Surrey and Sussex	-	1.169483	2.852681	-	-	-	2.114050	-	4.424605	-	5.423044	3.397756
26	Somerset and Wessex	-	3.770654	5.276596	-	-	-	2.114050	-	7.995342	-	9.842151	4.488518
27	West Devon and Cornwall	-	4.427568	14.580030	-	-	-	2.114050	-	12.373630	-	17.476641	8.675064

Changes to Wider Tariffs since 2026/27 Final Tariffs

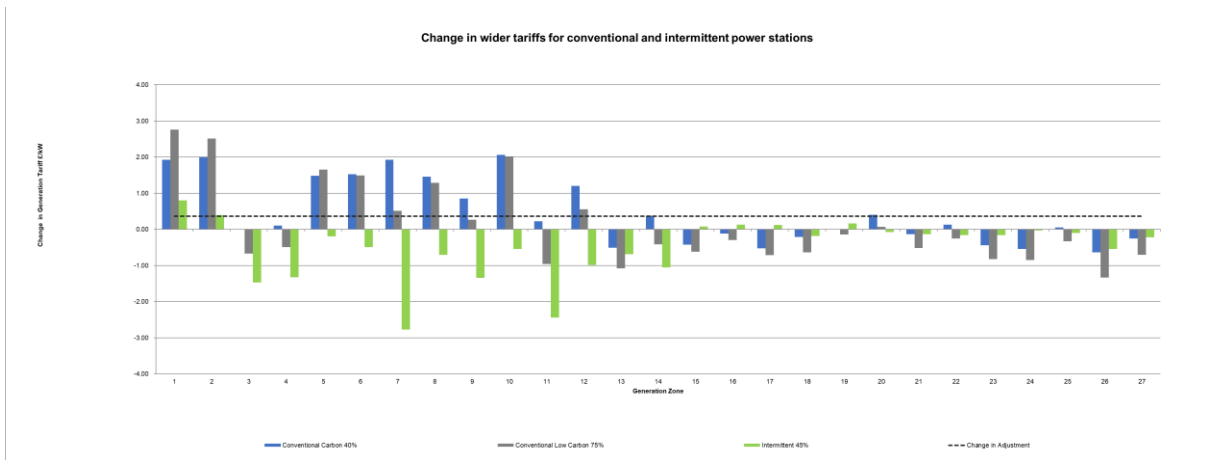
The following section provides details of the wider generation tariffs for 2027/28 and explains how these have changed since 2026/27. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only.



Table 3 Generation Wider Tariff Changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									Change In Adjustment
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
		2026/27 Final	2027/28 April	Change	2026/27 Final	2027/28 April	Change	2026/27 Final	2027/28 April	Change	
1	North Scotland	18.834210	20.759434	1.925224	38.725397	41.485944	2.760547	27.137522	27.938974	0.801452	0.362710
2	East Aberdeenshire	15.759398	17.756339	1.996941	31.490322	34.007222	2.516900	21.788613	22.184596	0.395983	0.362710
3	Western Highlands	18.604769	18.618957	0.014088	38.179324	37.506714	- 0.672610	26.664429	25.194429	- 1.470000	0.362710
4	Skye and Lochalsh	21.554534	21.660330	0.105796	45.652460	45.161701	- 0.490759	34.203381	32.883619	- 1.319762	0.362710
5	Eastern Grampian and Tayside	17.312999	18.801047	1.488048	32.017395	33.670035	1.652640	19.295694	19.105724	- 0.189970	0.362710
6	Central Grampian	16.699824	18.224566	1.524742	31.497875	32.992591	1.494716	19.440784	18.949352	- 0.491432	0.362710
7	Argyll	19.008466	20.935003	1.926537	39.064236	39.580983	0.516747	28.414808	25.640993	- 2.773815	0.362710
8	The Trossachs	13.560125	15.020424	1.460299	26.543088	27.834981	1.291893	16.626796	15.921955	- 0.704841	0.362710
9	Stirlingshire and Fife	12.383515	13.238383	0.854868	24.877679	25.145954	0.268275	15.889767	14.547288	- 1.342479	0.362710
10	South West Scotlands	11.419100	13.484867	2.064957	23.660797	25.685031	2.024234	15.515156	14.972606	- 0.542550	0.362710
11	Lothian and Borders	10.022391	10.247806	0.225415	18.294805	17.340144	- 0.954661	8.901035	6.459562	- 2.441473	0.362710
12	Solway and Cheviot	6.494472	7.698797	1.204325	13.802635	14.359209	0.556574	8.238128	7.255654	- 0.982474	0.362710
13	North East England	7.200522	6.691874	- 0.508648	11.903078	10.827390	- 1.075688	4.381359	3.696265	- 0.685094	0.362710
14	North Lancashire and The Lakes	2.635261	3.009505	0.374244	5.319924	4.909589	- 0.410335	1.018204	- 0.029456	- 1.047660	0.362710
15	South Lancashire, Yorkshire and Humber	4.187318	3.764821	- 0.422497	5.102829	4.484060	- 0.618769	- 1.260518	- 1.178682	0.081838	0.362710
16	North Midlands and North Wales	1.644655	1.532294	- 0.112361	1.982636	1.688825	- 0.293811	- 2.042214	- 1.912796	0.129418	0.362710
17	South Lincolnshire and North Norfolk	- 1.031757	- 1.554787	- 0.523030	0.062818	- 0.647114	- 0.709932	- 1.069448	- 0.947042	0.122406	0.362710
18	Mid Wales and The Midlands	- 0.399525	- 0.610233	- 0.210708	1.248033	0.612195	- 0.635838	- 0.358472	- 0.542358	- 0.183886	0.362710
19	Anglesey and Snowdon	3.023755	3.032391	0.008636	3.220609	3.078617	- 0.141992	- 2.223662	- 2.054617	0.169045	0.362710
20	Pembrokeshire	1.498029	1.904019	0.405990	- 1.342774	- 1.272350	0.070424	- 6.129220	- 6.197952	- 0.068732	0.362710
21	South Wales & Gloucester	- 3.502421	- 3.634813	- 0.132392	- 6.667868	- 7.184444	- 0.516576	- 6.546620	- 6.677862	- 0.131242	0.362710
22	Cotswold	- 5.753523	- 5.623340	0.130183	- 12.139607	- 12.392559	- 0.252952	- 13.774675	- 13.933958	- 0.159283	0.362710
23	Central London	- 7.249176	- 7.688756	- 0.439580	- 9.345749	- 10.167750	- 0.822001	- 6.625491	- 6.783584	- 0.158093	0.362710
24	Essex and Kent	- 3.884185	- 4.428212	- 0.544027	- 2.166273	- 3.016287	- 0.850014	- 0.268015	- 0.298718	- 0.030703	0.362710
25	Oxfordshire, Surrey and Sussex	- 4.478568	- 4.424605	0.053963	- 5.095981	- 5.423044	- 0.327063	- 3.301718	- 3.397756	- 0.096038	0.362710
26	Somerset and Wessex	- 7.363727	- 7.995342	- 0.631615	- 8.505988	- 9.842151	- 1.336163	- 3.945380	- 4.488518	- 0.543138	0.362710
27	West Devon and Cornwall	- 12.122570	- 12.373830	- 0.251060	- 16.776132	- 17.476641	- 0.700509	- 8.459911	- 8.675064	- 0.215153	0.362710

Figure 1 Variation in generation wider zonal tariffs



Locational Changes

Locational tariffs have been impacted by the update of various locational inputs, including the nodal generation and demand and the network model used to model flows. This means that there have been changes in the overall tariffs across each generation zone. This has resulted in increases to Conventional Carbon and Conventional Low Carbon tariffs in the North and decreases in the South; meanwhile Intermittent tariffs are expected to see decreases in most zones.



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 £0.36/kW since 2026/27, decreasing in magnitude, to become less negative. This is because the expected increase in charging base outweighs the decrease in revenue expected to be collected from wider tariffs, 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.

Table 4 shows the current view of onshore local Substation tariffs for 2027/28.

An indicative CPIH figure has been used to calculate the 2027/28 Local Substation tariffs and will be finalised when the October index is available.

Table 4 Onshore Local Substation Tariffs

		2027/28 April Local Substation Tariffs (£/kW)		
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.414097	0.171103	0.124718
<1320 MW	Redundancy	0.874864	0.379413	0.264454
≥1320 MW	No redundancy	-	0.520505	0.362994
≥1320 MW	Redundancy	-	0.796035	0.543927

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 2027/28 onshore Local Circuit Tariffs are indicative and will be refined in the next quarterly forecast. Table 5 shows the forecast 2027/28 onshore Local Circuit tariffs with the 2026/27 Local Circuit tariffs also included for comparison.

Seventeen new local circuits have been included in this 2027/28 forecast. Two Local Circuits have been removed since the 2026/27 Final Tariffs: Glenglass which is currently

expected to become a MITS node in 2027/28, and Tangy IV which is no longer expected to have any contracted TEC in 2027/28.

Table 5 Onshore Local Circuit Tariffs

Substation Name	2026/27 Final (£/kW)	2027/28 April (£/kW)	Change	Substation Name	2026/27 Final (£/kW)	2027/28 April (£/kW)	Change	Substation Name	2026/27 Final (£/kW)	2027/28 April (£/kW)	Change
Aberarder	1.781281	1.816008	0.034727	Dorenell	3.105306	3.165846	0.060540	LETHANS	-	2.961299	2.961299
Aberdeen Bay	1.979201	2.017787	0.038586	Douglas North	0.791891	0.807115	0.015434	Limekilns	0.944259	0.982668	0.018409
ACHANY EXTENSION	-	2.020590	2.020590	Dunhill	1.853914	1.890057	0.036143	Lochay	0.395840	0.403557	0.007717
Achruach	- 1.688946	- 1.722947	- 0.034001	Dunlaw Extension	0.552300	0.557067	0.004767	Larg	-	1.241451	1.241451
Aigas	0.914658	0.932490	0.017832	Dunmaglass	1.131444	1.153502	0.022058	Luichart	0.730641	0.743882	0.013041
Alcerri Devilla Battery Energy Storage Facility	-	0.894869	0.894869	Edinbane	8.906166	9.079664	0.173498	Marchwood	0.484012	- 0.311358	- 0.795370
An Suidhe	- 1.080984	- 1.104064	- 0.023080	Enoch Hill	0.791891	0.807115	0.015434	Marston Vale	- 0.634131	- 0.369425	0.264706
Arcleloch	1.979201	2.017787	0.038586	Ewe Hill	1.956469	1.994612	0.038143	MEYGEN	-	8.374190	8.374190
Arcleloch Extension	1.560493	1.590915	0.030422	Fallago	- 0.070115	- 0.081901	- 0.011786	Middle Muir	2.747132	2.800689	0.053557
Ayrshire Grid Collector	0.175914	0.179343	0.003429	Farr	4.499496	4.587216	0.087720	Middleton	0.198287	- 0.001302	- 0.199589
Beinneun Wind Farm	1.755575	1.789442	0.033867	Fernoch	5.576958	5.685686	0.108728	Millennium Wind	2.074890	2.114982	0.040092
Benbrack	0.947818	0.966296	0.018478	Festiniog	0.281261	0.286744	0.005483	Mossford	3.936831	4.012378	0.075547
Bhlaraidh Wind Farm	0.792780	0.808236	0.015456	Fife Grid Services	0.197495	0.201346	0.003851	Nant	- 1.618164	- 1.649718	- 0.031554
Black Hill	1.986337	2.025061	0.038724	Finlarig	0.395840	0.403557	0.007717	Pont Abraham	- 0.149034	- 0.152178	- 0.003144
Blackcraig	7.205463	7.345937	0.140474	Foyers	0.361621	0.368871	0.007050	RAWHILLS	-	0.365919	0.365919
Blacklaw	2.177122	2.219566	0.042444	Galawhistle	1.359052	1.385548	0.026496	Rhigos	0.129859	0.132309	0.002450
Blacklaw Extension	4.735809	4.828136	0.092327	Glen Kyllachy	1.297708	1.323008	0.025300	Rocksavage	0.019158	0.019531	0.000373
BRAIDFIELD	-	1.455308	1.455308	Glen Ullinish windfarm	8.962794	9.137395	0.174601	Saltend	- 0.020052	- 0.020445	- 0.000393
Broken Cross	1.384436	1.411382	0.026946	Glen Ullinish windfarm Extension	-	10.314471	10.314471	Sandy Knowe	5.957759	2.623123	- 3.334636
Chirmorie	1.657364	1.689675	0.032311	Glendoe	2.595416	2.646015	0.050599	Sanquhar II	5.115075	1.764010	- 3.351065
CHLEANSID	-	1.212354	1.212354	Gordonbush	- 0.114377	0.069699	0.184076	Scoop Hill	-	0.569037	0.569037
Cloiche	-	0.574192	0.574192	GREENBURN	-	3.748521	3.748521	Shepherds Rig	0.089438	0.086828	- 0.002610
Clyde (North)	0.137760	0.140446	0.002686	Griffin Wind	12.573856	12.823822	0.249966	South Humber Bank	- 0.229171	- 0.234144	- 0.004973
Clyde (South)	0.160720	0.163854	0.003134	Hadyard Hill	3.562563	3.632017	0.069454	Spalding	0.348099	0.352208	0.004109
Coalburn BESS	0.488649	0.499175	0.009526	Harestanes	2.968902	3.028681	0.059779	St Fergus Mobil	1.319433	1.345156	0.025723
Corriegarth	3.166722	3.228459	0.061737	Hartlepool	0.041262	0.040390	- 0.000872	Stranoch	2.765717	2.819636	0.053919
Corriemallie	2.054961	2.093820	0.038859	High Constellation	-	1.984511	1.984511	Strathbrora	- 0.239253	- 0.071396	0.167857
Coryton	0.050744	0.051380	0.000636	Hopsrig collector	3.143990	3.205284	0.061294	Strathy South	-	1.527711	1.527711
Creag Riabhach	4.354243	4.439132	0.084889	Invergarry	0.395840	0.403557	0.007717	Strathy Wind	1.359052	1.385548	0.026496
Cruachan	2.291529	2.335841	0.044312	Kergord	63.624132	64.869258	1.245126	Strathy Wood	3.521899	3.590560	0.068661
Culham Jet	-	- 0.039835	- 0.039835	Kilgallioch	0.229600	0.234077	0.004477	Stronelairg	1.389843	1.420113	0.030270
Culligran	2.249748	2.293608	0.043860	Kilmarnock BESS	0.508195	0.518102	0.009907	Wester Dod	0.453017	0.461849	0.008832
Cumberhead Collector	0.906035	0.923698	0.017663	Kilmorack	0.160696	0.163829	0.003133	Whitelee	0.137760	0.140446	0.002686
Cumberhead West	4.801520	4.895128	0.093608	KINMUCK	-	0.032261	- 0.032261	Whitelee Extension	0.390321	0.397930	0.007609
Deanie	3.696014	3.768070	0.072056	Kype Muir	1.925324	1.962859	0.037535	Yaxley	0.145488	0.082972	- 0.062516
Dersalloch	2.917798	2.974682	0.056884	Laig South	1.070147	1.091299	0.021152				
Dinawig	3.235969	3.299056	0.063087	Langage	- 0.415421	- 0.423729	- 0.008308				

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 Knowe 132kV	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	Corriegarh 132kV	4km Cable	4km OHL	Corriegarh
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. Since January, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs for projects expected to transfer in 2026/27 or 2027/28 will be confirmed once asset transfer has taken place and tariffs have been set.

Table 7 Offshore local tariffs 2027/28

Offshore Generator	2026/27 Final Tariff Component (£/kW)			2027/28 April Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.800544	62.353306	1.548318	12.062854	63.739333	1.582735	0.262310	1.386027	0.034417
Beatrice	10.338561	28.173956	-	10.522284	28.674626	-	0.183723	0.500670	-
Burbo Bank Extension	15.078754	29.114438	-	15.346714	29.631821	-	0.267960	0.517383	-
Dudgeon	22.039112	34.557346	-	22.430762	35.171453	-	0.391650	0.614107	-
East Anglia 1	13.794649	58.160449	-	14.039789	59.193999	-	0.245140	1.033550	-
Galloper	22.714718	35.821692	-	23.118374	36.458268	-	0.403656	0.636576	-
Greater Gabbard	21.810479	50.495911	-	22.295296	51.618365	-	0.484817	1.122454	-
Gunfleet Sands I	25.748620	23.745060	4.438088	26.320976	24.272880	4.536741	0.572356	0.527820	0.098653
Gunfleet Sands II	25.748620	23.745060	4.438088	26.320976	24.272880	4.536741	0.572356	0.527820	0.098653
Gwyn y mor	33.795163	33.246524	-	34.395726	33.837337	-	0.600563	0.590813	-
Hornsea 1A	12.366525	38.668860	-	12.586286	39.356032	-	0.219761	0.687172	-
Hornsea 1B	12.366525	38.668860	-	12.586286	39.356032	-	0.219761	0.687172	-
Hornsea 1C	12.366525	38.668860	-	12.586286	39.356032	-	0.219761	0.687172	-
Hornsea 2A	11.581216	39.257213	-	11.793728	39.977571	-	0.212512	0.720358	-
Hornsea 2B	11.581216	39.257213	-	11.793728	39.977571	-	0.212512	0.720358	-
Hornsea 2C	11.581216	39.257213	-	11.793728	39.977571	-	0.212512	0.720358	-
Humber Gateway	19.350923	44.076959	-	19.694802	44.860236	-	0.343879	0.783277	-
Lincs	22.854684	86.806805	-	23.260827	88.349420	-	0.406143	1.542615	-
London Array	15.064079	51.706203	-	15.331778	52.625057	-	0.267699	0.918854	-
Moray East	12.496093	31.289336	-	12.718157	31.845369	-	0.222064	0.556033	-
Ormonde	36.724993	67.654370	0.539149	37.541339	69.158233	0.551134	0.816346	1.503863	0.011985
Race Bank	13.624728	37.759017	-	13.866849	38.430020	-	0.242121	0.671003	-
Rampion	11.851012	30.795892	-	12.061612	31.343156	-	0.210600	0.547264	-
Robin Rigg	- 0.798686	44.793291	14.351485	- 0.816440	45.788984	14.670499	- 0.017754	0.995693	0.319014
Robin Rigg West	- 0.798686	44.793291	14.351485	- 0.816440	45.788984	14.670499	- 0.017754	0.995693	0.319014
Seagreen 1	11.825189	21.449883	-	12.042178	21.843482	-	0.216989	0.393599	-
Sheringham Shoal	34.666415	40.811823	0.887129	35.437001	41.719013	0.906849	0.770586	0.907190	0.019720
Thanet	26.589531	49.782470	1.198439	27.180579	50.889065	1.225079	0.591048	1.106595	0.026640
Triton Knoll	11.584709	34.530373	-	11.790577	35.144001	-	0.205868	0.613628	-
Walney 1	31.485699	62.945098	-	32.185582	64.344280	-	0.699883	1.399182	-
Walney 2	32.453015	65.871256	-	33.174400	67.335483	-	0.721385	1.464227	-
Walney 3	14.172132	28.631120	-	14.423980	29.139914	-	0.251848	0.508794	-
Walney 4	14.172132	28.631120	-	14.423980	29.139914	-	0.251848	0.508794	-
West of Duddon Sands	12.191409	60.724975	-	12.408059	61.804099	-	0.216650	1.079124	-
Westernmost Rough	24.816259	42.215878	-	25.257261	42.966083	-	0.441002	0.750205	-

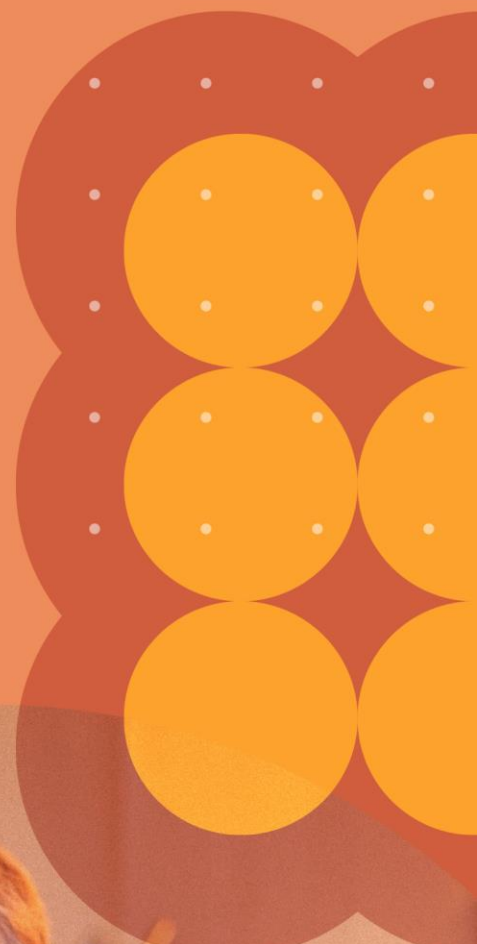
Demand Tariffs

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 Final	2027/28 April	Change
Unmetered (p/kWh/annum)	2.568147	3.068032	0.499885
Average Demand Residual (£/MWh)	25.68147	30.68032	4.998850
Demand Residual (£m)	6,265.2	7,584.8	1,319.6

HH Tariffs (Locational)	2026/27 Final	2027/28 April	Change
Average Tariff (£/kW)	2.793189	3.479981	0.686793

EET	2026/27 Final	2027/28 April	Change
Average Tariff (£/kW)	3.045116	3.366767	0.321651
AGIC (£/kW)	3.143391	3.204673	0.061282
Embedded Export Volume (GW)	6.713095	7.645681	0.932586
Total Credit (£m)	20.442156	25.741225	5.299069

NHH Tariffs (locational)	2026/27 Final	2027/28 April	Change
Average (p/kWh)	0.381869	0.483541	0.101672

Compared to the 2026/27 Final tariffs, both the average HH & NHH demand tariffs are forecast to increase. Revenue to be recovered through the demand residual is forecast to be £1.32bn higher than 2026/27, however this is £1.18bn lower than forecast in last year's 5-year view.

The average HH gross tariff is forecast to be £3.48/kW, an increase of £0.69/kW compared to 2026/27 Final tariffs. The average NHH tariff is forecast to be 0.48p/kWh, an increase of 0.10p/kWh compared to 2026/27 Final tariffs.

The forecast Embedded Export Volume for 2027/28 forecast to be 7.65 GW which is 0.93 GW higher than 2026/27. The total credit paid out to embedded generators (<100 MW) is currently forecast to be £25.7m, an increase of £5.3m compared to 2026/27 Final Tariff expectations. The average Embedded Export Tariff (EET) is now forecast to be £3.37/kW, an increase of £0.32/kW compared to 2026/27 Final tariffs.



Table 9 Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	0.809519
7	East Midlands	0.230675	0.032180	3.435348
8	Midlands	3.555364	0.490768	6.760037
9	Eastern	1.317511	0.193894	4.522184
10	South Wales	6.557388	0.823086	9.762061
11	South East	5.871060	0.864400	9.075733
12	London	7.986827	0.880626	11.191500
13	Southern	8.405911	1.169712	11.610584
14	South Western	15.404273	2.289536	18.608946

Demand Residual Tariffs

Site counts have been updated using the latest trends for each voltage level

Consumption data that is used to determine the proportion of the demand residual revenue to be recovered from each charging band has been updated using the latest actual data and observed trends to create a forecast of consumption for the period October 2025 to September 2026.

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 spreadsheet⁵. The residual band thresholds will remain the same for the duration of the RII0-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.

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



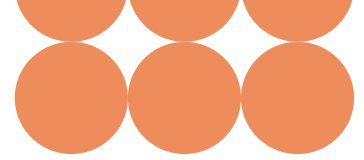
Table 10 Non-Locational demand residual charges

Band		2026/27 Final	2027/28 April	Change
Domestic		0.222566	0.257643	0.035077
LV_NoMIC_1		0.239315	0.263362	0.024047
LV_NoMIC_2		0.587299	0.729530	0.142231
LV_NoMIC_3		1.242416	1.587827	0.345411
LV_NoMIC_4		3.461015	4.379177	0.918162
LVI		5.797398	7.139101	1.341703
LV2		11.511840	14.176046	2.664206
LV3		14.381374	17.709681	3.328307
LV4		38.180103	47.016191	8.836088
HV1	Tariff - £/Site/Day	31.839048	39.412715	7.573667
HV2		117.152788	145.020615	27.867827
HV3		185.418505	229.525103	44.106598
HV4		528.912335	654.727845	125.815510
EHV1		325.476550	402.855098	77.378548
EHV2		1,159.381475	1,427.699181	268.317706
EHV3		2,512.930533	3,110.690173	597.759640
EHV4		5,698.386405	7,053.881657	1,355.495252
T-Demand1		1,401.949529	1,675.061745	273.112216
T-Demand2		2,931.228837	3,619.000184	687.771347
T-Demand3		7,586.413858	9,366.458461	1,780.044603
T-Demand4		20,829.236682	25,716.522168	4,887.285486

Unmetered demand		p/kWh	p/kWh	
Unmetered		2.568147	3.068032	0.499885

Demand Residual (£m)		6265.17	7584.8	1319.62

Transmission Demand Residual tariffs are forecast to increase by 21% on average compared to 2026/27 Final Tariffs, driven by the increase in revenue to be collected.



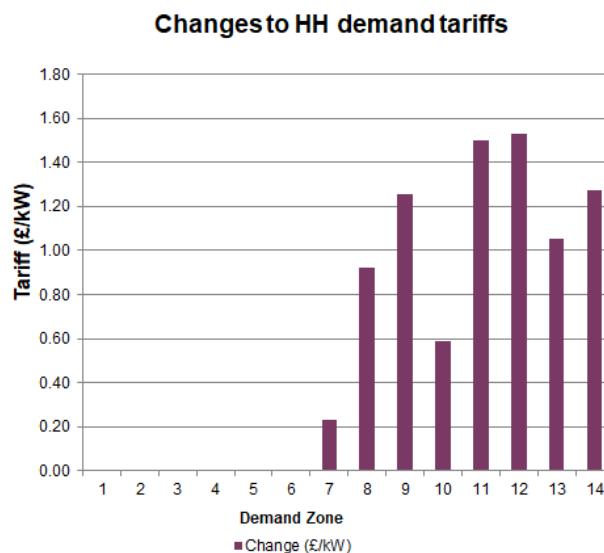
Half-Hourly Demand Tariffs

Table 11 shows the gross HH demand tariffs for 2027/28, compared to the 2026/27 Final Tariffs.

Table 11 Half-Hourly Demand Tariffs

Zone	Zone Name	2026/27 Final (£/kW)	2027/28 April (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	0.230675	0.23068
8	Midlands	2.633945	3.555364	0.92142
9	Eastern	0.063093	1.317511	1.254418
10	South Wales	5.969709	6.557388	0.58768
11	South East	4.368073	5.871060	1.502987
12	London	6.453239	7.986827	1.533588
13	Southern	7.354150	8.405911	1.051761
14	South Western	14.130209	15.404273	1.27406

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, there are fluctuations in tariffs for zones 7 through to 14. These are due to the changes in Nodal demand and embedded generation forecasts. Zones 1 to 6 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 2027/28.

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

Site Code	Site Name	DNO 1	DNO 2	DNO 3	DNO 1		DNO 2		DNO 3		Demand Site			Embedded Export Site			
		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 Tariff Floored (£/kW)	AGIC £/kW	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	EET Tariff Floored (£/kW)
AMEM	Amersham	9	13	0	2.175658	-0.858146	2.839116	5.566795	0.000000	0.000000	2.507387	2.354324	4.861711	3.204673	2.507387	2.354324	8.066384
AXMI	Axminster	13	14	0	2.839116	5.566795	3.078826	12.325447	0.000000	0.000000	2.958971	8.946121	11.905092	3.204673	2.958971	8.946121	15.109765
BARK	Barking	9	12	0	2.175658	-0.858146	5.552244	2.434583	0.000000	0.000000	3.863951	0.788218	4.652169	3.204673	3.863951	0.788218	7.856842
BEDD	Beddington	11	12	0	4.808119	1.062940	5.552244	2.434583	0.000000	0.000000	5.180182	1.748762	6.928943	3.204673	5.180182	1.748762	10.133616
BRIM	Brimsdown	9	12	0	2.175658	-0.858146	5.552244	2.434583	0.000000	0.000000	3.863951	0.788218	4.652169	3.204673	3.863951	0.788218	7.856842
CARR	Carrington	4	6	0	-2.188967	-3.394575	-2.553623	0.158469	0.000000	0.000000	-2.371295	-1.618053	0.000000	3.204673	-2.371295	-1.618053	0.000000
CELL	Cellarhead	6	8	0	-2.553623	0.158469	-1.421726	4.977091	0.000000	0.000000	-1.987675	2.567780	0.580105	3.204673	-1.987675	2.567780	3.784778
ECLA	East Claydon	7	13	0	-1.738728	1.969404	2.839116	5.566795	0.000000	0.000000	0.550194	3.768099	4.318293	3.204673	0.550194	3.768099	7.522966
GREN	Grendon	9	7	0	2.175658	-0.858146	-1.738728	1.969404	0.000000	0.000000	0.218465	0.555629	0.774093	3.204673	0.218465	0.555629	3.978766
IROA	Iron Acton	8	10	0	-1.421726	4.977091	-3.472233	10.029621	0.000000	0.000000	-2.446980	7.503356	5.056376	3.204673	-2.446980	7.503356	8.261049
KIBY	Kirkby	6	4	0	-2.553623	0.158469	-2.188967	-3.394575	0.000000	0.000000	-2.371295	-1.618053	0.000000	3.204673	-2.371295	-1.618053	0.000000
LALE	Laleham	11	13	0	4.808119	1.062940	2.839116	5.566795	0.000000	0.000000	3.823618	3.314867	7.138485	3.204673	3.823618	3.314867	10.343158
LEMR	Lea Marston (was Hams Hall)	7	8	0	-1.738728	1.969404	-1.421726	4.977091	0.000000	0.000000	-1.580227	3.473247	1.893020	3.204673	-1.580227	3.473247	5.097693
LITT	Littlebrook	11	12	0	4.808119	1.062940	5.552244	2.434583	0.000000	0.000000	5.180182	1.748762	6.928943	3.204673	5.180182	1.748762	10.133616
MELK	Melksham	13	14	0	2.839116	5.566795	3.078826	12.325447	0.000000	0.000000	2.958971	8.946121	11.905092	3.204673	2.958971	8.946121	15.109765
WALP	Walpole	7	9	0	-1.738728	1.969404	2.175658	-0.858146	0.000000	0.000000	0.218465	0.555629	0.774093	3.204673	0.218465	0.555629	3.978766
WISD	Willesden	13	12	0	2.839116	5.566795	5.552244	2.434583	0.000000	0.000000	4.195680	4.000689	8.196369	3.204673	4.195680	4.000689	11.401042



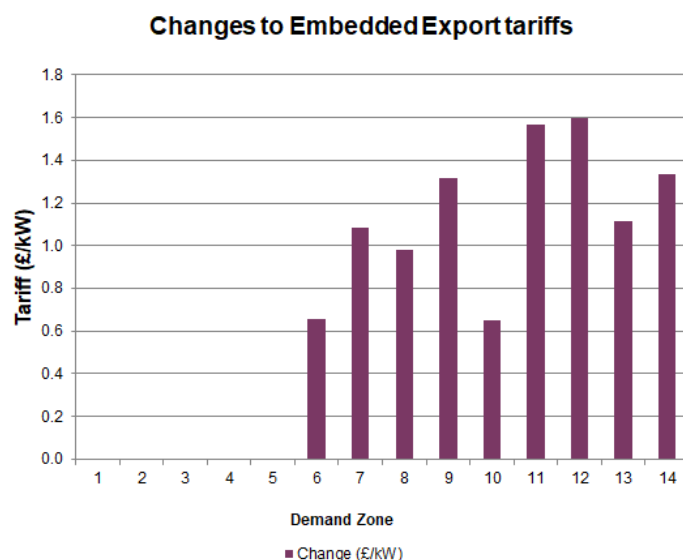
Embedded Export Tariffs (EET)

Table 13 shows the Embedded Export tariffs for 2027/28, compared to the 2026/27 Final Tariffs.

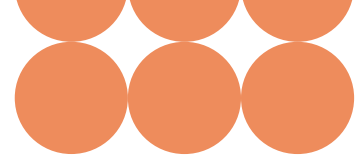
Table 13 Embedded Export Tariffs

Zone	Zone Name	2026/27 Final (£/kW)	2027/28 April (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.153008	0.809519	0.65651
7	East Midlands	2.353700	3.435348	1.081648
8	Midlands	5.777336	6.760037	0.98270
9	Eastern	3.206484	4.522184	1.315700
10	South Wales	9.113100	9.762061	0.64896
11	South East	7.511464	9.075733	1.564269
12	London	9.596630	11.191500	1.594870
13	Southern	10.497541	11.610584	1.113043
14	South Western	17.273600	18.608946	1.33535

Figure 3 Embedded export tariff changes



The average EET is £3.37/kW, an increase of £0.32/kW since 2026/27. The Embedded Export Volume is forecast to be 7.65 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.



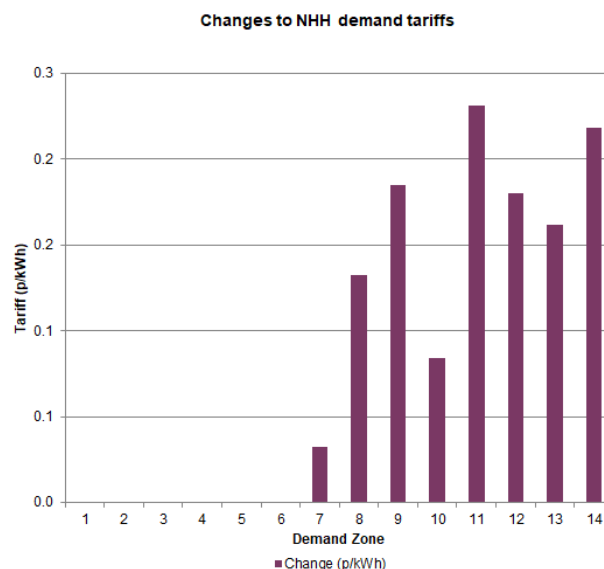
Non-Half-Hourly Demand Tariffs

Table 14 and Figure 4 show the changes in Non-Half-Hourly tariffs for 2027/28, compared to the 2026/27 Final Tariffs.

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2026/27 Final (p/kWh)	2027/28 April (p/kWh)	Change (p/kWh)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	0.032180	0.032180
8	Midlands	0.358668	0.490768	0.13210
9	Eastern	0.009140	0.193894	0.184754
10	South Wales	0.739032	0.823086	0.08405
11	South East	0.633420	0.864400	0.230980
12	London	0.700677	0.880626	0.179949
13	Southern	1.008120	1.169712	0.161592
14	South Western	2.071095	2.289536	0.21844

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2027/28 is 0.48p/kWh, a 0.10p/kWh increase compared to the 2026/27 Final Tariffs. 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 this forecast process.

Inputs affecting the locational element of tariffs

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

- Expected Contracted generation (until October 2026 when it will be based on contracted TEC);
- 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 2027/28 period, which can be found on the TEC register⁶. The contracted TEC volumes are based on the 03 March 2026 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 September forecasts, we forecast our best view of modelled TEC. However, for our November Draft Tariffs and January Final Tariffs we will use the contracted TEC position as published in the TEC register as of 31 October 2026, 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 2027/28 and liable to pay generation TNUoS charges.

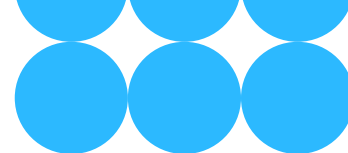
Table 15 Contracted, Modelled & Chargeable TEC

Generation (GW)	2026/27 Final	2027/28 Tariffs			
		Initial	September	Draft	Final
Contracted TEC	120.14	138.22			
Modelled Best View TEC	For input to locational tariffs post 31st October please see Contracted TEC	136.52		For input to locational tariffs post 31st October please see Contracted TEC	
Chargeable TEC	101.64	121.81			

Adjustments for Interconnectors

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

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



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

The table below reflects the contracted position of interconnectors for 2027/28 as stated in the interconnector register⁷ as of 03 March 2026.

Table 16 Interconnectors Contracted TEC

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
The Superconnection	Creyke Beck 400kV Substation	Iceland	15	0	1,000	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 website⁸.

In accordance with CUSC 14.15.10, we must use the ETYS network model data including updates up to 31 October 2026. Due to a delay in the next ETYS publication, the network model is currently 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 2027/28 Expansion

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

⁸ neso.energy/publications/electricity-ten-year-statement-etyts



Constant is forecast to be £19.531062/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-ET1 value which was set in 2013/14 and will continue to increase in-line with inflation each year. A review of the EC methodology and the expansion factors is ongoing with the industry (CMP315/375), any impact will be included in our forecast publications once the modification has concluded.

Locational Onshore Security Factor

The locational onshore security factor, (also called the global security factor), 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](https://www.neso.energy/document/183406/download).

The locational onshore security factor was recalculated ahead of the new price control and is 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 publication, onshore substation tariffs are based on the values set for RIIO-ET3, inflated by CPIH.

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 were 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.

For this publication, offshore local tariffs are based on the values set for RIIO-ET3 (or at asset transfer, if later), inflated in line with the relevant OFTO's revenue.

Allowed Revenues

The majority of the TNUoS charges look to recover the allowed revenue for the Onshore and Offshore Transmission Owners (TO) 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, with the current RIIO-ET3 period running 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). For this publication, we have included a five-year view of allowed revenues, based on the Onshore and Offshore TO submissions in January, with NESO updated inflation assumptions. The forecast for 2027/28 and beyond will continue to be revised throughout the year, with final 2027/28 revenues based on Onshore and Offshore TO final submissions in January 2027.

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

£m Nominal	2026/27 Final	2027/28	2028/29	2029/30	2030/31	2031/32
ONTO Income from TNUoS						
National Grid Electricity Transmission	3,287.0	4,012.2	4,644.4	5,241.3	5,802.1	5,925.6
Scottish Power Transmission	1,082.9	1,468.4	1,498.8	1,624.2	1,717.1	1,746.0
SHE Transmission	2,083.1	2,551.2	3,308.2	3,777.7	3,874.4	4,033.7
Total ONTO Income from TNUoS	6,453.0	8,031.8	9,451.4	10,643.2	11,393.6	11,705.3
Other Income from TNUoS						
Other Pass-through from TNUoS	112.4	92.7	81.3	74.5	71.3	57.5
Offshore (plus interconnector contribution / allowance)	1,045.3	990.4	1,326.3	1,403.9	1,425.6	1,517.3
Total Other Income from TNUoS	1,157.7	1,083.0	1,407.6	1,478.4	1,496.9	1,574.8
Total to Collect from TNUoS	7,610.7	9,114.8	10,859.0	12,121.7	12,890.5	13,280.1

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 (£7.97m) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is an increase of £0.86m to local charges associated with pre-existing assets since the 2026/27 Final Tariff publication.

Table 18 Generation and demand revenue proportions

Code	Revenue	2026/27 Final	2027/28 Tariffs			
			Initial	September	Draft	Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50			
y	Error Margin	30.3%	30.3%			
ER	Exchange Rate (€/£)	1.19	1.15			
MAR	Total Revenue (£m)	7,610.05	9,114.15			
GO	Generation Output (TWh)	199.28	214.00			
G	% of revenue from generation	16.18%	15.20%			
D	% of revenue from demand	83.82%	84.80%			
G.R	Revenue recovered from generation (£m)	1,231.67	1,385.70			
D.R	Revenue recovered from demand (£m)	6,378.38	7,728.45			
Breakdown of generation revenue						
	Revenue from the Peak element	150.54	164.68			
	Revenue from the Year Round Shared element	210.77	280.22			
	Revenue from the Year Round Not Shared element	174.51	129.93			
	Revenue from Onshore Local Circuit tariffs	49.53	56.04			
	Revenue from Onshore Local Substation tariffs	28.95	35.88			
	Revenue from Offshore Local tariffs	869.12	976.46			
	Revenue from the adjustment element	-251.75	-257.51			
G.MAR	Total Revenue recovered from generation (£m)	1,231.67	1,385.70			
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	7.11	7.97			



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 2026 EFO⁹. This figure is indicative, as per OBR’s March EFO, at € 1.146366/£.

Generation Output

The forecast output of generation is 214 TWh and has been updated for 2027/28. This figure is the average of the Future Energy Scenarios in the 2025 Future Energy Scenarios (FES).

Error Margin

The error margin for 2027/28 tariffs will be updated and finalised in the next quarterly forecast, following publication of the outturn of 2025/26 data. In this report, the error margin is the same as we used for 2026/27 Final tariffs, derived from historical data in the past five whole years (thus for year 2026/27, we used data from years 2020/21 – 2024/25).

⁹ obr.uk/docs/OBR_Economic_and_fiscal_outlook_March_2026_Annex_Tables



Table 19 Generation revenue error margin calculation

Calculation for			
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted 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 Onshore 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.

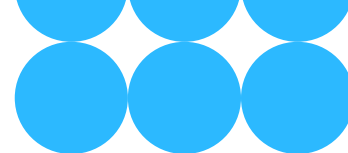


Table 20 Onshore local circuit tariff elements associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Project Name	Pre-existing local circuit tariff (£/kW)
Aberarder Wind Farm	£ 0.807115	Galawhistle Wind Farm	£ -
Aberdeen Offshore Wind Farm	£ -	Glen App Windfarm	£ -
Achany Extension Wind Farm	£ -	Glen Kyllachy Wind Farm	£ -
A'Chruach Wind Farm	£ -	Glen Ullinish Extension	£ -
Afton Wind Farm	£ -	Greenburn Mixed Technology	£ -
Aikengall II Windfarm	£ -	Harting Rig Wind Farm	£ -
Aikengall Ila Wind Farm	£ -	Hartlepool	£ -
Alcemi Devilla Battery Energy Storage Facility	£ -	Hopsrig Wind Farm	£ -
Arecleoch Extension Windfarm	£ 1.086469	Hunterston Energy Storage Facility	£ -
Beinneun Wind Farm	£ 0.062550	Kennoxhead Wind Farm Extension	£ 2.800689
Benbrack wind farm	£ 0.461849	Kilmarnock BESS	£ -
Bhlaraidh Wind Farm	£ -	Kincardine Battery Storage Facility	£ -
Blacklaw	£ -	Kinmuck PV and BESS Station	£ -
Blacklaw Extension	£ -	Kype Muir	£ -
Braidfield Battery Storage	£ -	Lairg II Wind Farm	£ -
Broken Cross Windfarm	£ -	Lethans Wind Farm	£ -
Builth Wells	£ -	Lethans Wind Farm Extension	£ -
Carraig Gheal Wind Farm	£ 5.685503	Limekiln	£ -
Chirmorie Wind Farm	£ 1.629141	Lochluichart	£ -
Chleansaid Wind Farm	£ -	Loganhead Windfarm	£ -
Cloiche Wind Farm	£ -	Lorg Wind Farm	£ -
Clyde North	£ -	Marchwood	£ -
Clyde South	£ -	MeyGen Tidal	£ -
Corriegarh	£ -	Middle Muir Wind Farm	£ -
Coryton ENERGY	£ -	Pen Y Cymoedd Wind Farm	£ -
Crossdykes	£ -	Pencloe Windfarm	£ -
Cruachan	£ -	Rawhills Battery Energy Storage Facility	£ -
Cumberhead	£ -	Rocksavage	£ -
Cumberhead West Wind Farm	£ -	Saltend	£ -
Dalquhandy Wind Farm	£ -	Sandy Knowe Wind Farm	£ -
Dealnach WLC WF	£ -	Sanquhar II Wind Farm	£ -
Dersalloch Wind Farm	£ -	Shepherds Rig Wind Farm	-£ 0.116969
Dinorwig	£ -	Spalding	£ -
Dorenell Windfarm	£ -	Stranoch Wind Farm	£ 1.629141
Douglas West	£ 0.807115	Strathy South Wind	£ -
Douglas West Extension	£ -	Strathy Wood	£ -
Edinbane Windfarm	£ -	Stronelaig	£ 0.265490
Enoch Hill	£ -	Viking Wind Farm	£ 0.001229
Ewe Hill	£ -	Whitelee Extension	£ -
Fallago Rig Wind Farm	£ -	Windy Rig Wind Farm	£ -
Ffestiniog	£ -	Windy Standard II (Brockloch Rig) Wind Farm	£ -
Foyers	£ -	Windy Standard III Wind Farm	£ -
Aggregated pre-existing TEC (MW)		17,033	



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	0.414097	37.20
Toddleburn Wind Farm	0.414097	

Charging Bases for 2027/28

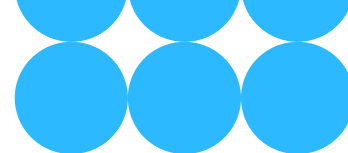
Generation

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 2027/28 tariffs is forecast at 121.81 GW, which is an increase of 20.16 GW since 2026/27. It is based on our internal view of what generation we expect to connect next financial year.

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



Demand

Our forecasts of chargeable HH demand, NHH demand and embedded generation for 2027/28 have been updated for this 2027/28 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 spreadsheet¹⁰ for a detailed breakdown of the demand charging bases.

Table 22 Charging Bases

Charging Bases	2026/27 Final	2027/28 Tariffs			
		Initial	September	Draft	Final
Generation (GW)	101.64	121.81			
NHH Demand (4pm-7pm TWh)	22.77	23.06			
Gross charging					
Total Average Gross Triad (GW)	47.54	48.32			
HH Demand Average Gross Triad (GW)	16.71	16.63			
Embedded Generation Export (GW)	6.71	7.65			

Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 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 website¹¹.

¹⁰ Please see the Numerical Data section of 'Tools and supporting information' for the link to the published tables excel spreadsheet.

¹¹ 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

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

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 the site counts being billed and reflect the RIIO-ET3 re-banding, which took effect from April 2026.

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



Table 23 Residual & Adjustment components calculation

Component		2026/27 Final	2027/28 Tariffs			
			Initial	September	Draft	Final
G	Proportion of revenue recovered from generation (%)	16.18%	15.20%			
D	Proportion of revenue recovered from demand (%)	83.82%	84.80%			
R	Total TNUoS revenue (£m)	7,610.05	9,114.15			
Generation revenue breakdown (without adjustment)						
Z _g	Revenue recovered from the wider locational element of generator tariffs (£m)	535.82	574.83			
O	Revenue recovered from offshore local tariffs (£m)	869.12	976.46			
L _g	Revenue recovered from onshore local substation tariffs (£m)	28.95	35.88			
S _g	Revenue recovered from onshore local circuit tariffs (£m)	49.53	56.04			
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	7.11	7.97			
Generation adjustment tariff calculation						
	Limit on generation tariff (€/MWh)	2.50	2.50			
	Error Margin	30.3%	30.3%			
	Exchange Rate (€/£)	1.19	1.15			
	Total generation Output (TWh)	199.28	214.00			
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	291.18	325.29			
	Adjustment Revenue (£m)	(251.75)	(257.51)			
B _G	Generator charging base (GW)	101.64	121.81			
AdjTariff	Generator adjustment tariff (£/kW)	(2.48)	(2.11)			
Gross demand residual						
R _d	Demand residual (£m)	6,265.2	7,584.8			
Z _d	Revenue recovered from the locational element of demand tariffs (£m)	133.65	169.40			
EE	Amount to be paid to Embedded Export Tariffs (£m)	-20.44	-25.74			
B _d	Demand Gross charging base (GW)	47.54	48.32			

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 initial forecast of 2027/2028 Tariffs on Wednesday 20 May. We will be sending out a communication to those who subscribe to our updates via the NESO website, providing details on the upcoming webinar and how to register. For any questions, please see our contact details below.

Charging model copies available

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

Numerical data

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

neso.energy/document/380286/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.

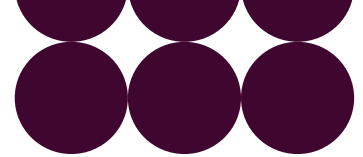
TNUoS tariffs consist of two components: locational based charges that vary by zone, and non-locational or 'residual' charges. Residual charges ensure complete revenue recovery for transmission owners (as per the Price Control framework). The TNUoS methodology determines the proportion of revenue to 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 \geq 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.

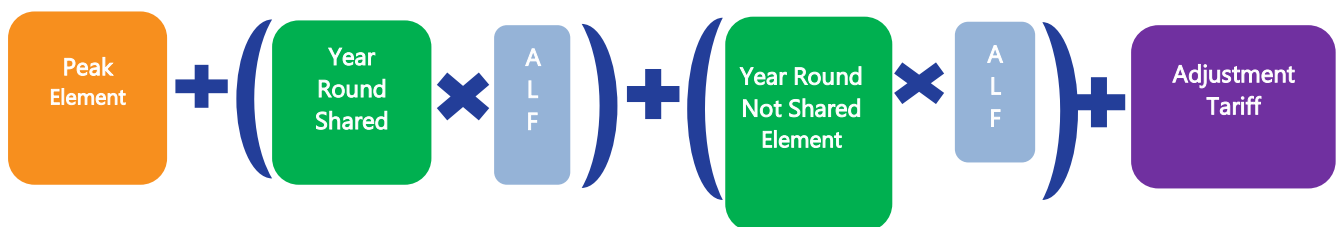
† Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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

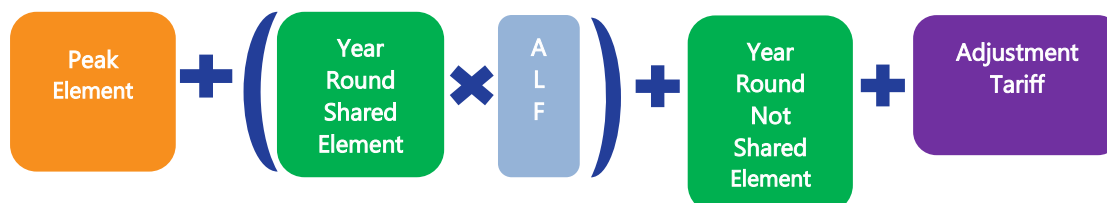
(for example: Biomass, CHP, Coal, Gas, Pumped Storage, Battery)





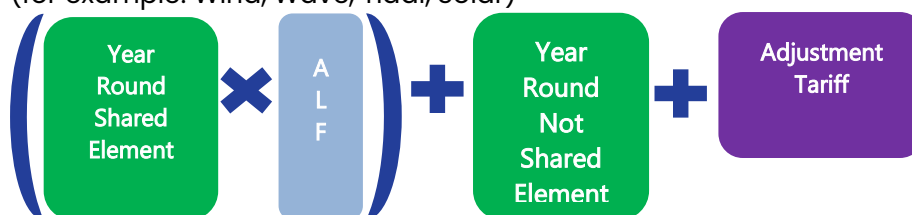
Conventional Low Carbon Generators

(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 BEGA¹² if they want to export power onto the transmission system from the distribution network using “firm” transmission network capacity. Generators will incur local DUoS¹³ 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:

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

¹² Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: [neso.energy/industry-information/connections](https://www.neso.energy/industry-information/connections)

¹³ 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 year¹⁴. 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 website¹⁵.

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).

¹⁴ neso.energy/industry-information/charging/tnuos-charges#Triads-data

¹⁵ 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 website¹⁶.

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.

¹⁶ neso.energy/industry-information/charging/charging-documentation

Appendix B: Changes and proposed changes to the charging methodology





Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications that could affect the TNUoS tariff calculation methodology for 2027/28. Each modification requires approval from Ofgem, and if any Workgroup Alternative CUSC Modifications (WACMs) are proposed, Ofgem will determine which, if any, are approved.

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

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

A summary of modifications already in progress which could affect 2027/28 tariffs are listed below:

Table 24 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change
CMP288	Explicit charging arrangements for customer delays and backfeeds	Potential impact on non-locational tariffs only
CMP315/CMP375	Expansion Constant & Expansion Factor Review	Affects TNUoS locational tariffs for generators and demand users
CMP316/CMP397	TNUoS Arrangements for Co-located Generation Sites	Affects TNUoS locational tariffs
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.
CMP405	TNUoS Locational Demand Signals for Storage	Change demand locational tariffs so they are not floored at zero



CMP419	Generation Zoning Methodology Review	Seeks to review the existing generation zoning methodology to incorporate offshore assets connected as part of the Holistic Network Design (HND) to enable the wider tariff to be applied to offshore generators
CMP423	Generated Weighted Reference Node	Seeks to change the way the Tariff and Transport model calculates tariffs. There would be no change to the structure of the tariffs, or any other aspect of charging
CMP426	TNUoS charges for transmission circuits identified for the HND to add capacity across boundaries	Considers the cost recovery for circuits classified as boundary reinforcement within the Holistic Network Design (HND), ensuring their purpose and function are considered when setting the TNUoS tariff and identifying the users the costs are recovered from.
CMP433	Optimised Transmission Investment Cost model	Seeks to replace the Transport component of the Transport and Tariff (T&T) model with an economic market model
CMP440	Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor	Seeks to reintroduce negative locational tariffs for demand
CMP442	Introducing the option to fix Generator TNUoS charges	Seeks to give Generators the opportunity to fix their wider TNUoS charges against the forecast tariffs provided by NESO.
CMP445	Pro-rating first year TNUoS for Generators	Seeks to ensure that Generators only pay TNUoS on a pro-rated basis from their Charging Date, during the first year of connection.

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 2026/27 and this 2027/28 Forecast.

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).

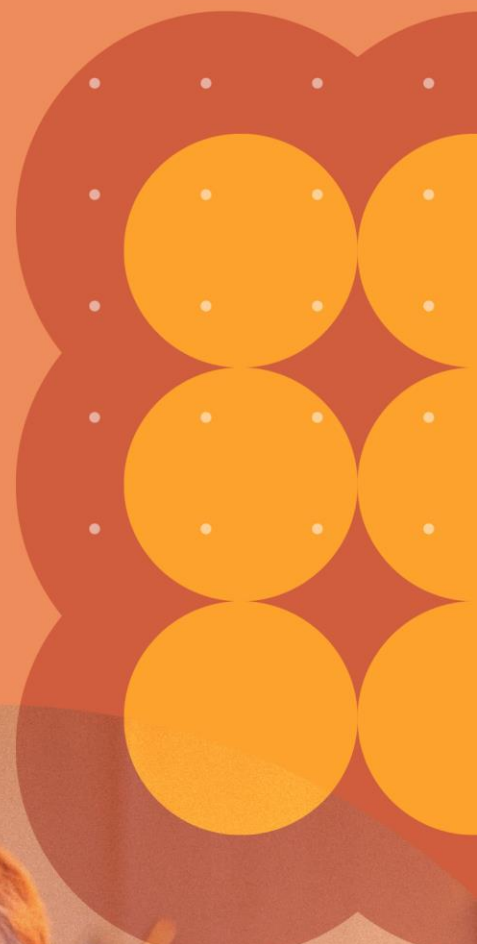
Table 25 Location elements of the HH demand tariff for 2027/28

Demand Zone	2026/27 Final		2027/28 April		Changes	
	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1 Northern Scotland	- 2.490073	- 37.248832	- 2.298509	- 38.486797	0.191564	- 1.237965
2 Southern Scotland	- 2.966429	- 24.811726	- 3.257550	- 26.609440	- 0.291121	- 1.797714
3 Northern	- 5.043729	- 9.661553	- 4.311020	- 8.994197	0.732709	0.667356
4 North West	- 1.832830	- 4.386530	- 2.188967	- 3.394575	- 0.356136	0.991955
5 Yorkshire	- 4.090189	- 1.947045	- 3.701827	- 1.347964	0.388363	0.599081
6 N Wales & Mersey	- 1.994929	- 0.995454	- 2.553623	0.158469	- 0.558695	1.153923
7 East Midlands	- 2.095433	1.305742	- 1.738728	1.969404	0.356705	0.663662
8 Midlands	- 0.725749	3.359694	- 1.421726	4.977091	- 0.695978	1.617397
9 Eastern	1.660538	- 1.597445	2.175658	- 0.858146	0.515120	0.739298
10 South Wales	- 3.101888	9.071597	- 3.472233	10.029621	- 0.370345	0.958024
11 South East	4.361389	0.006685	4.808119	1.062940	0.446731	1.056256
12 London	5.004241	1.448998	5.552244	2.434583	0.548004	0.985585
13 Southern	2.722927	4.631223	2.839116	5.566795	0.116190	0.935572
14 South Western	2.993167	11.137042	3.078826	12.325447	0.085659	1.188405

Table 26 Elements of the Embedded Export Tariff for 2027/28

Demand Zone	2026/27 Final		2027/28 April		Changes	
	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1 Northern Scotland	- 39.738905	3.143391	- 40.785306	3.204673	- 1.046401	0.061282
2 Southern Scotland	- 27.778155	3.143391	- 29.866990	3.204673	- 2.088835	0.061282
3 Northern	- 14.705283	3.143391	- 13.305217	3.204673	1.400066	0.061282
4 North West	- 6.219360	3.143391	- 5.583542	3.204673	0.635818	0.061282
5 Yorkshire	- 6.037234	3.143391	- 5.049791	3.204673	0.987444	0.061282
6 N Wales & Mersey	- 2.990383	3.143391	- 2.395154	3.204673	0.595228	0.061282
7 East Midlands	- 0.789691	3.143391	0.230675	3.204673	1.020366	0.061282
8 Midlands	2.633945	3.143391	3.555364	3.204673	0.921419	0.061282
9 Eastern	0.063093	3.143391	1.317511	3.204673	1.254418	0.061282
10 South Wales	5.969709	3.143391	6.557388	3.204673	0.587679	0.061282
11 South East	4.368073	3.143391	5.871060	3.204673	1.502986	0.061282
12 London	6.453239	3.143391	7.986827	3.204673	1.533589	0.061282
13 Southern	7.354150	3.143391	8.405911	3.204673	1.051762	0.061282
14 South Western	14.130209	3.143391	15.404273	3.204673	1.274064	0.061282

Appendix D: Annual Load Factors





ALFs

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

For the purposes of this forecast, we have used the final version of the 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 2027/28 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2026. 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](https://www.neso.energy/document/376346/download)
- Specific ALFs in excel format: [neso.energy/document/376351/download](https://www.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) will be fixed using the TEC register as of 31 October 2026, as required by the CUSC 14.15.6 and no further changes to Contracted TEC will be made after that point.

Table 28 shows the contracted generation changes that are expected since the 2026/27 position, using data from the March 2026 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100 MW TEC are not chargeable and are not included in this table.

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Achany Extension Wind Farm	105	ACHE10	1
Airnoch BESS	89	WLEX20	10
Alcemi Devilla Battery Energy Storage Facility	500	ALDB29	9
Awel Y Mor	574	BODE40	16
Axminster	50	AXMI40_SEP	26
Ayr Energy Storage	150	AYR-2Q	10
Berkswell Energy Storage	200	BESW20	18
Blackhillock Battery	349	BLHI40	1
Bradford West 100MW	100	BRAW20	15
Braidfield Battery Storage	100	BRDB10	8
Bridgwater (tertiary)	-57	BRWA4A	26
Bryn Tilti	-106	LEGA40	18
Carnedd Wen Wind Farm	-150	TRAW10	16
Carrington	80	CARR20	16
Cellarhead 400kV Energy Storage	300	CELL40_SPM	18
Chapelcross Solar PV and Storage	150.88	CHAP10	12
Chickerell Solar PV & BESS	400	CHIC40	26
Chleansaid Wind Farm	96	CHLS10	1
Cloiche Wind Farm	200	CLOI10	5
Corriearth 2 Wind Farm	70	COGA10	1
Creag Riabhach Wind Farm	13	CREA10	1
Cruachan	40	CRUA20	8



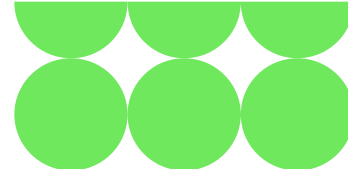
Power Station	MW Change	Node	Generation Zone
Culham Storage	500	CULJ4A	25
Dersalloch Wind Farm Extension	16	DESAIQ	10
Didcot Energy Park	300	DIDC40	25
Didcot Road	300	DIDC40	25
Drakelow	120	DRAK40	18
East Anglia Two	860	BRFO40	18
Eggborough CCGT - OCGT - BESS	451	EGGB40	15
Elvanfoot (9.8 MW) Energy Storage	9.8	ELVA40	11
Enderby Tertiary	57	ENDE40	18
Enoch Hill 2 Wind Farm	10	ENHI10	10
Essendine	240	RYHA40	17
Exeter BESS	290	EXET40	26
Fferm Solar Pentir	57	PENT40	19
Fiddlers Ferry BESS	300	FIDF20_SPM	15
Flash Solar Farm	360	STAY40	16
Fleet Solar PV	-57	FLEE40	25
Flemyland Battery Storage	100	KILW1Q	10
Gaerwen Wind Farm	67	TRAW40	16
Gammidge PV & BESS Park	41	GREN40_EME	18
Glen Ullinish Extension	240	GLUE10	4
Glennifer Road BESS	150	NEIL10	10
Glentagart 42MW BESS	42	REDS40	11
Greenburn Mixed Technology	90	GRBN10	10
Harestanes	38.3	HARE10	12
High Constellation Windfarm	50	HICL10	7
Highview Hunterston East Cryobattery	200	HUNE40	10
Hopsrig Wind Farm	48	HORI10	12
Immingham	50	HUMR40	15
Iver	50	IVER4A	25
Kilmarnock South Battery Storage	500	KILS40	10
Kinmuck PV and BESS Station	105	KINM2A	1
Kirkby (Tertiary)	57	KIBY20	15
Lanarkshire BESS	500	STHA40	11
Langbank Solar and BESS	49.9	DEVM10	10
Legacy Green Energy Centre	400	LEGA40	18
Lethans Wind Farm	132	LETH10	10
Lethans Wind Farm Extension	85	LETH10	10
Littlebrook BESS	300	LITT40	24
Loganhead Windfarm	36	HORI10	12



Power Station	MW Change	Node	Generation Zone
Lorg Wind Farm	69.5	LORG10	10
Menter Mon Morlais Anglesey Marine Energy	40	WYLF10	19
MeyGen Tidal	28	MEYG10	1
Neilston 400kV Greener Grid Park	600	NEIL40	10
Net Zero Teesside Power Project	860	TODP20	13
Newarthill Energy Park	300	NEAR2Q	9
Norton PV and BESS	40.9	NORT20	13
Oaklands Farm Solar PV	162	DRAK40	18
Ocker Hill - Gresham House	240	OCKH20	18
Oldbury (Tertiary)	50	OLDB4A	18
Ouse Energy Storage	249	KEMS40	24
Pembroke BESS	350	PEMB40	20
Penketh Hall Farm	249.9	FIDF20_SPM	15
Pentland Floating Offshore Wind Farm	100	DOUN10	1
Penwortham BESS	57	PEWO40	15
Rawhills Battery Energy Storage Facility	500	RAWH40	11
Rochdale BESS	57	ROCH20	15
Sandy Knowe Wind Farm	22	SAKN10	10
Scoop Hill Wind Farm	500	SCOPI0	12
Smeaton BESS	228	SMEA4R	11
Strathy South Wind	207.6	STSO10	1
Sundon Storage	500	SUND40	18
Tangy IV WF	-96	TNGF10	7
The Superconnection	1000	CREB40	15
Thurrock Power Station	450	TILB20	24
Tormsdale Windfarm	70	MYBS11	1
Twyn Hywel Cillfynydd	107.8	CILF40	21
Walpole 2 (tertiary)	100	WALP40_EME	17
Warley	57	WARL20	24
West Burton	120	WBUR40	16
West Burton B	500	WBUR40	16
West Weybridge (Tertiary)	7	WWEY20	25
West Weybridge EL	57	WWEY20	25
Whitehill Battery Storage	200	EERH20	9
Willington East 1 (Tertiary)	47.5	WILE40	18
Willington Energy Park	500	WILE40	18
Zenobe Coalburn Battery Storage	200	COAL40	11
Zenobe Stalybridge Project	150	STAL20	16
Vicarage Drove BESS	-1200	CREB40	15

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 the Onshore and Offshore 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 three Onshore TOs – National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT), and Scottish Hydro Electric Transmission (SHET) – and Offshore TOs 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.

Compared to 2026/27, there has been an increase in Onshore and Offshore TO allowed revenues, offset by a net decrease in the adjustment term and other passthrough items.

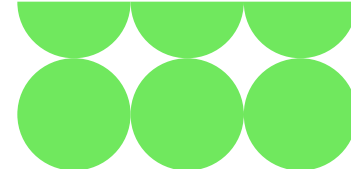


Table 29 NESO revenue breakdown

Term £m nominal	NESO TNUoS Other Pass-Through				
	2026/27 Final	Initial Forecast	September Forecast	December Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.67	0.67			
Network Innovation Competition Fund (NICFt)	0.00	0.00			
Strategic Innovation Fund (SIFt)	47.86	37.67			
The Adjustment Term (ADJt)	4.65	-2.54			
Offshore Transmission Revenue (OFTot), Interconnectors Cap & Floor Revenue Adjustment (TICFt) and Interconnectors Payment Term (ICPt)	1,045.26	990.39			
Site Specific Charges Discrepancy (DlSt)	0.00	0.00			
Termination Sums (TSt)	0.00	0.00			
NGET revenue pass-through (NGETTot)*	3,287.05	4,012.24			
SPT revenue pass-through (TSPT)	1,082.88	1,468.36			
SHETL revenue pass-through (TSHT)	2,083.09	2,551.18			
NESO Bad debt (BDt)	0.00	0.00			
NESO other pass-through items (Lft + ITct etc)	56.84	56.84			
NESO legacy adjustment (LART)	0.00	0.00			
Total	7,608.30	9,114.82	0.00	0.00	0.00

Onshore TOs (NGET, SPT and SHET) revenue forecast

The allowed revenue forecast for the three Onshore TOs (NGET, SPT and SHET) was provided to us in January 2026, as required by STCP24-1, with NESO updated inflation using the latest CPIH data. Total Onshore TO revenue is forecast to be £8,031.98m, a £1,578.76m increase compared to 2026/27. (NGET, £725.19m, SPT £385.48m, SHET £468.09m).

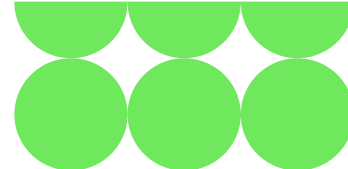
NGET allowed revenue is forecast in line with the allowed revenue as published in the RIIO-ET3 Final Determinations PCFM^{17,18}, with updates to inflation.

SPT allowed revenue forecast reflects the RIIO-ET3 final determination, with post final determinations adjustments agreed with Ofgem. Generally, allowances determined by Ofgem are shown; and SPT also include forecasts for anticipated future Ofgem determinations in respect of the Iteration adjustment reflecting the latest view of totex, changes to allowed totex, inflation and Weighted Average Cost of Capital (WACC).

SHET allowed revenue forecasts include an increase in base allowed totex compared to the final year of RIIO-T2. This uplift drives higher fast money, depreciation and return, resulting from an increase in the Company's regulated asset value (RAV). The forecast for 2027/28 also reflects the current best estimate of delivery, based on the business's best

¹⁷Revised 16 December in their Statutory Consultation on the RIIO-3 Licence Drafting Modifications

¹⁸ [ofgem.gov.uk/consultation/modifications-riio-3-licences-and-associated-documents](https://www.ofgem.gov.uk/consultation/modifications-riio-3-licences-and-associated-documents)



view of all factors within and outside their control including consenting processes and supplier negotiations.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2027/28 is forecast to be £1.24bn, an increase of £107.6m since 2026/27. Revenues have been adjusted using updated revenue submissions provided by the OFTOs, in addition to the latest RPI and CPI data (as part of the calculation of each OFTO's inflation term, as defined in the relevant OFTO licence). The 2027/28 forecast includes £249.5m of forecast revenue (20% 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.

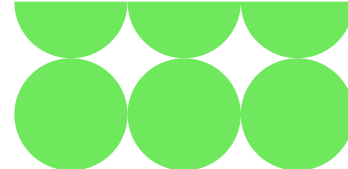


Table 30 NGET allowed revenue breakdown

Transmission Revenue Forecast All monies £m (nominal) unless stated otherwise			National Grid Electricity Transmission				
			Initial Forecast	September Forecast	December Draft	January Final	
Inflation 2018/19		PI2018/19	352.84	-	-	-	Per 16 December PCFM Submission
Inflation		PIt	395.56	-	-	-	NESO updated inflation assumption using CPIH actuals to March 2026
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	3,574.08	-	-	-	Per 16 December PCFM Submission
Price Control Financial Model Iteration Adjustment	A2	ADJt	0.00	-	-	-	
[ADJt = Rt * PIt / PI2018/19 + ADJt]	A	ADJt	4,006.83	-	-	-	
SONIA	B1	It-1	0.00%	-	-	-	
Allowed Revenue	B2	ARt-1	0.00	-	-	-	
Recovered Revenue	B4	RRt-1	0.00	-	-	-	
Correction Term [Kt = (ARt-1 - RRt-1) * (1 + It-1 + 1.15%)]	B	Kt	0.00	-	-	-	
Legacy pass-through	C1	LPT	5.40	-	-	-	Per 16 December PCFM Submission
Legacy MOD	C2	LMOdt	0.00	-	-	-	
Legacy K correction	C3	LKt	0.00	-	-	-	
Legacy TRU term	C4	LTRUt	0.00	-	-	-	
Close out of the RIIO-ETI stakeholder satisfaction output	C5	LSSOt	0.00	-	-	-	
Close out of the RIIO-1 adjustment in respect of the Environment	C6	LEDRT	0.00	-	-	-	
Close out of the RIIO-ETI Incentive in respect of the sulphur he	C7	LSFit	0.00	-	-	-	
Close out of the RIIO-ETI reliability incentive in respect of ener	C8	LRIt	0.00	-	-	-	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	-	-	-	
Legacy Adjustment [LAR = LPT + LMOdt + LKt + LTRUt + NOCOt + LSSOt + LEDRT + LSFIt + LRIt]	C	LARt	0.00	-	-	-	
Site Rental Charges							
Total Allowed Revenue [ARt = ADJt + Kt + LARt]	D	ARt	4,012.24				Recalculated based on Inflation Assumption Update

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
- Grey lines are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed.
- Inflation (PIt) updated since January submission to include CPIH actuals to March 2026.

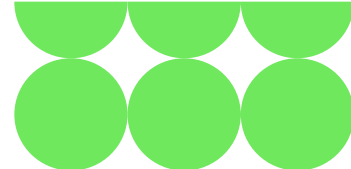


Table 31 SPT allowed revenue breakdown

Transmission Revenue Forecast All monies £m (nominal) unless stated otherwise			Scottish Power Transmission				Notes
			Initial Forecast	September Forecast	December Draft	January Final	
Inflation 2018/19		PI2018/19	352.84	-	-	-	April to March 2023/24 average RPI
Inflation		PI _t	395.56	-	-	-	NESO updated inflation assumption using CPIH actuals to March 2026
Opening Base Revenue Allowance (2018/19 prices)	A1	R _t	1,304.26	-	-	-	
Price Control Financial Model Iteration Adjustment	A2	ADJ _t	0.00	-	-	-	ADJ not applicable in RIIO-T3
[ADJ_t = R_t * PI_t / PI2018/19 + ADJ_t]	A	ADJ_t	1,462.18				
SONIA	B1	It-1	0.00%				
Allowed Revenue	B2	AR _{t-1}	0.00				
Recovered Revenue	B4	RR _{t-1}	0.00				
Correction Term [K_t = (AR_{t-1} - RR_{t-1}) * (1 + It-1 + 1.15%)]	B	K_t	0.00				For the Regulatory Year commencing on 1 April 2026, the value of K is zero.
Legacy pass-through	C1	LPT	0.00	-	-	-	
Legacy MOD	C2	LMOD _t	6.18	-	-	-	
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 Environment	C6	LED _t	0.00	-	-	-	
Close out of the RIIO-ET1 Incentive in respect of the sulphur he	C7	LSF _t	0.00	-	-	-	
Close out of the RIIO-ET1 reliability incentive in respect of ener	C8	LR _t	0.00	-	-	-	
Close out of RIIO-1 Network Outputs	C9	LNOCO _t	0.00	-	-	-	
Legacy Adjustment [LAR = LPT + LMOD_t + LK_t + LTRU_t + LNOCO_t + LSSO_t + LED_t + LSF_t + LR_t]	C	LAR_t	6.18				
Site Rental Charges							
Total Allowed Revenue [AR_t = ADJ_t + K_t + LAR_t]	D	AR_t	1,468.36				

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
- Grey lines are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed
- NIC payments are not included as they do not form part of TO's Maximum Revenue
- Inflation (PI_t) updated since January submission to include CPIH actuals to March 2026.

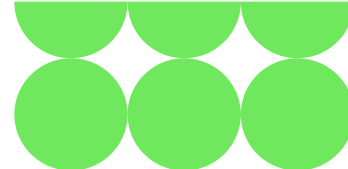


Table 32 SHET allowed revenue breakdown

Transmission Revenue Forecast All monies £m (nominal) unless stated otherwise			SHE Transmission				Notes
			Initial Forecast	September Forecast	December Draft	January Final	
Inflation 2018/19		PI2018/19	283.31	-	-	-	April to March 2018/19 average RPI.
Inflation		PIt	395.56	-	-	-	NESO updated inflation assumption using CPIH actuals to March 2026
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,827.22	-	-	-	Increasing expenditure anticipated from delivery of SSEN Transmission's T3 portfolio as set out in Ofgem's final determination. This results in a continued uplift in fast money, depreciation and returns for the period as a consequence of an uplift to company RAV.
Price Control Financial Model Iteration Adjustment	A2	ADJt	0.00	-	-	-	Annual Iteration Process adjustment term
[ADJRT = Rt * PI2018/19 + ADJt]	A	ADJRT	2,551.18	-	-	-	
SONIA	B1	It-1	3.48%	-	-	-	Nominal - SONIA rates reflect the Ofgem Final Determination PCFM.
Allowed Revenue	B2	ARt-1	2,083.09	-	-	-	Reflective of higher revenue allowances in 2026/27 with over recovery flowing through the k-correction term.
Recovered Revenue	B4	RRT-1	2,083.09	-	-	-	Forecast recovered revenue reflective of Final Determination PCFM, being no more than allowed revenue.
Correction Term [Kt = (ARt-1 - RRT-1) * (1 + It-1 + 1.15%)]	B	Kt	0.00	-	-	-	For the Regulatory Year, the K value provides a correction of over or under recovery of revenue in the previous year. In the T3 PCFM this is shown in the legacy K factor term but is disclosed here due to template requiring an update to T3 terms.
Legacy pass-through	C1	LPT	0.00	-	-	-	Pass through revenue accounts for the full business rates pass through and is based on model calculations for pass through costs from ET1. No further legacy pass-through -ET2 pass through captured in allowed revenue above.
Legacy MOD	C2	LMODt	0.00	-	-	-	Updated to reflect the RIIO-2 legacy adjustment factor (LADJt) per Ofgem's Final Determination PCFM published on 18th Dec 2025.
Legacy K correction	C3	LKt	0.00	-	-	-	Legacy correction factor closed out in 2022/23. No further legacy correction factor.
Legacy TRU term	C4	LTRUt	0.00	-	-	-	Legacy TRU term to close out the RIIO-T1 TRU term such that revenue between 1 April 2021 to 1 April 2025 reflects TRU adjustments relating to inflation forecasts used in RIIO-T1 period.
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	-	-	-	Final year of legacy ET1 incentive in 2022/23. Nil value from 2023/24 RIIO-T2 price control.
Close out of the RIIO-1 adjustment in respect of the Environment	C6	LEDRT	0.00	-	-	-	EDR incentive for 2020/21 awarded in 2022/23 being the two year lag flow through and final year of legacy ET1 incentives. Nil value from 2023/24 RIIO-T2 price control.
Close out of the RIIO-ET1 incentive in respect of the sulphur he	C7	LSFIT	0.00	-	-	-	Final year of legacy ET1 incentive in 2022/23. Nil value from 2023/24 RIIO-T2 price control.
Close out of the RIIO-ET1 reliability incentive in respect of ener	C8	LRIt	0.00	-	-	-	Final year of legacy ET1 incentive in 2022/23. Nil value from 2023/24 RIIO-T2 price control.
Close out of RIIO-1 Network Outputs	C9	NOCOT	0.00	-	-	-	No further close out.
Legacy Adjustment [LAR = LPT + LMODt + LKt + LTRUt + NOCOT + LSSOt + LEDRT + LSFIT + LRIt]	C	LART	0.00	-	-	-	
Site Rental Charges							
Total Allowed Revenue [ARt = ADJRT + Kt + LARt]	D	ART	2,551.18	-	-	-	

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
- Grey lines are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed.
- Inflation (PIt) updated since January submission to include CPIH actuals to March 2026.

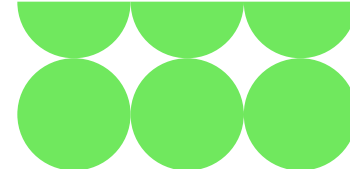


Table 33 Offshore Revenues

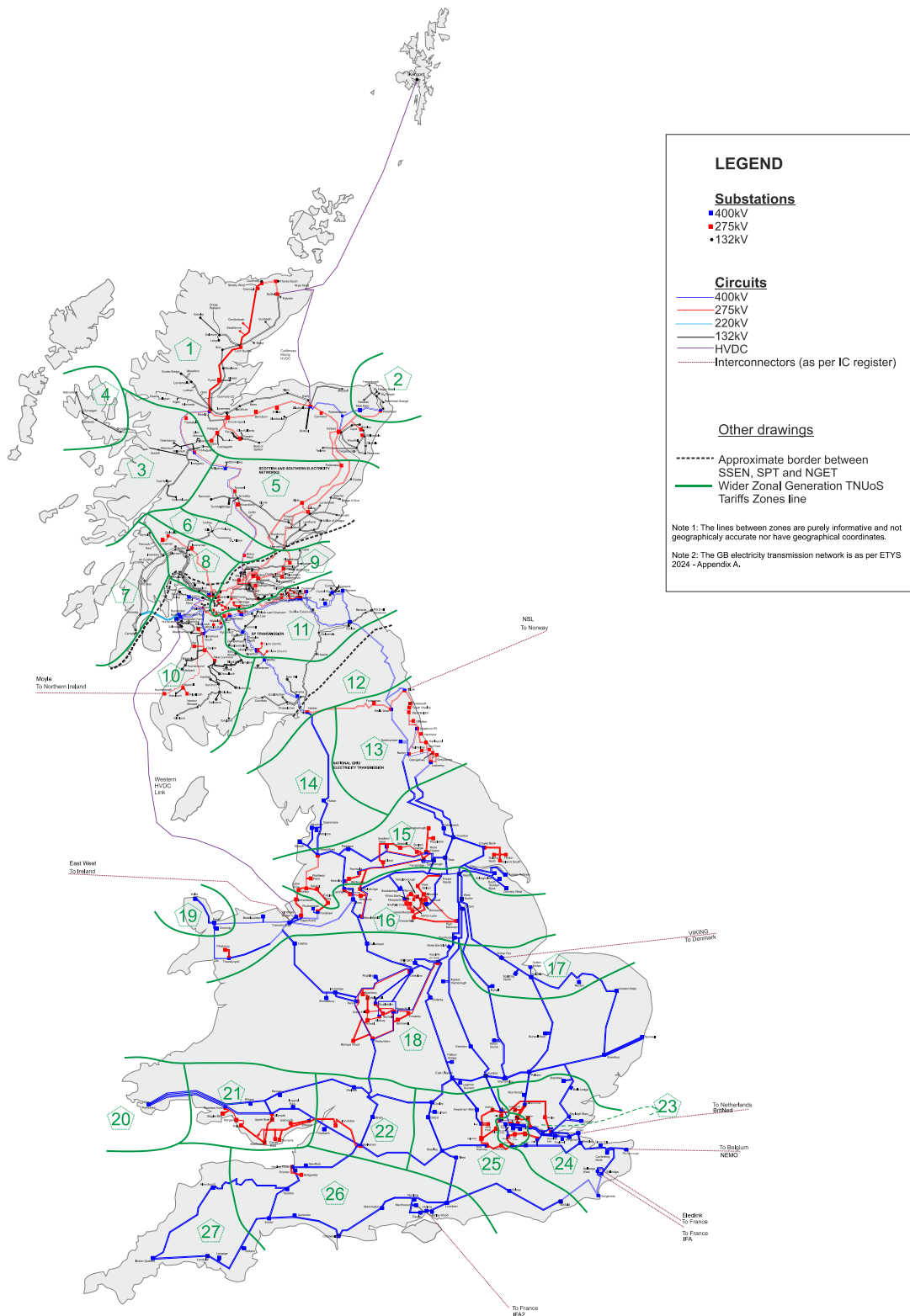
Offshore Transmission Revenue Forecast (£m)	Year							Notes
Regulatory Year	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	
Barrow	6.7	7.0	7.8	8.5	8.8	9.2	9.5	Current revenues plus indexation
Gunfleet	8.4	8.7	9.7	10.7	11.1	11.6	11.9	Current revenues plus indexation
Walney 1	15.3	15.6	17.8	19.4	20.3	21.1	21.5	Current revenues plus indexation
Robin Rigg	9.4	9.8	10.9	12.0	12.4	12.9	13.2	Current revenues plus indexation
Walney 2	15.1	16.3	18.3	20.0	20.9	21.8	22.3	Current revenues plus indexation
Sheringham Shoal	23.4	24.2	26.7	29.5	30.0	32.1	32.8	Current revenues plus indexation
Ormonde	14.1	14.7	16.2	17.9	18.6	19.1	19.8	Current revenues plus indexation
Greater Gabbard	32.1	33.2	37.0	38.8	41.6	43.8	44.9	Current revenues plus indexation
London Array	44.7	46.8	52.6	57.3	59.1	61.7	63.0	Current revenues plus indexation
Thanet	20.8	21.6	24.0	26.3	27.4	28.2	29.1	Current revenues plus indexation
Lincs	30.0	32.5	34.0	40.9	40.1	42.1	42.9	Current revenues plus indexation
Gwynn y mor	32.9	39.8	37.6	37.4	78.8	75.7	41.7	Current revenues plus indexation
West of Duddon Sands	25.3	25.5	28.5	30.3	32.3	33.7	34.3	Current revenues plus indexation
Humber Gateway	14.4	13.3	15.0	16.6	17.4	17.8	18.1	Current revenues plus indexation
Westermost Rough	14.1	14.7	16.5	18.0	18.6	19.5	19.9	Current revenues plus indexation
Burbo Bank Extension	14.1	14.7	16.4	17.7	18.4	19.3	19.6	Current revenues plus indexation
Dudgeon	19.6	20.8	22.6	24.9	26.2	27.5	28.0	Current revenues plus indexation
Race Bank	27.4	28.9	32.5	35.4	36.5	38.1	38.9	Current revenues plus indexation
Galloper	17.1	17.8	20.1	21.9	22.5	23.5	24.0	Current revenues plus indexation
Walney 3	13.5	14.1	15.9	17.3	17.8	18.6	19.0	Current revenues plus indexation
Walney 4	13.5	14.1	15.9	17.3	17.8	18.6	19.0	Current revenues plus indexation
Hornsea 1A		18.4	20.6	22.2	22.9	24.6	24.9	Current revenues plus indexation
Hornsea 1B		18.4	20.6	22.2	22.9	24.6	24.9	Current revenues plus indexation
Hornsea 1C	137.1	18.4	20.6	22.2	22.9	24.6	24.9	Current revenues plus indexation
Beatrice		21.1	24.4	25.7	26.5	28.1	32.0	Current revenues plus indexation
Rampion		15.5	17.4	19.7	20.3	21.3	21.8	Current revenues plus indexation
East Anglia 1			47.4	51.8	54.8	57.3	58.6	Current revenues plus indexation
Hornsea 2A				25.3	27.3	28.4	28.9	Current revenues plus indexation
Hornsea 2B				25.3	27.3	28.4	28.9	Current revenues plus indexation
Hornsea 2C				25.3	27.3	28.4	28.9	Current revenues plus indexation
Triton Knoll				41.3	42.7	46.6	46.9	Current revenues plus indexation
Moray East				28.2	50.0	52.6	53.6	Current revenues plus indexation
Seagreen 1						44.5	46.1	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2026/27				52.6	89.6	130.4	136.4	NESO Forecast
Forecast to asset transfer to OFTO in 2027/28						0.0	113.1	NESO Forecast
Offshore Transmission Pass-Through	549.0	594.3	765.6	879.8	1,010.9	1,135.5	1,243.1	

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



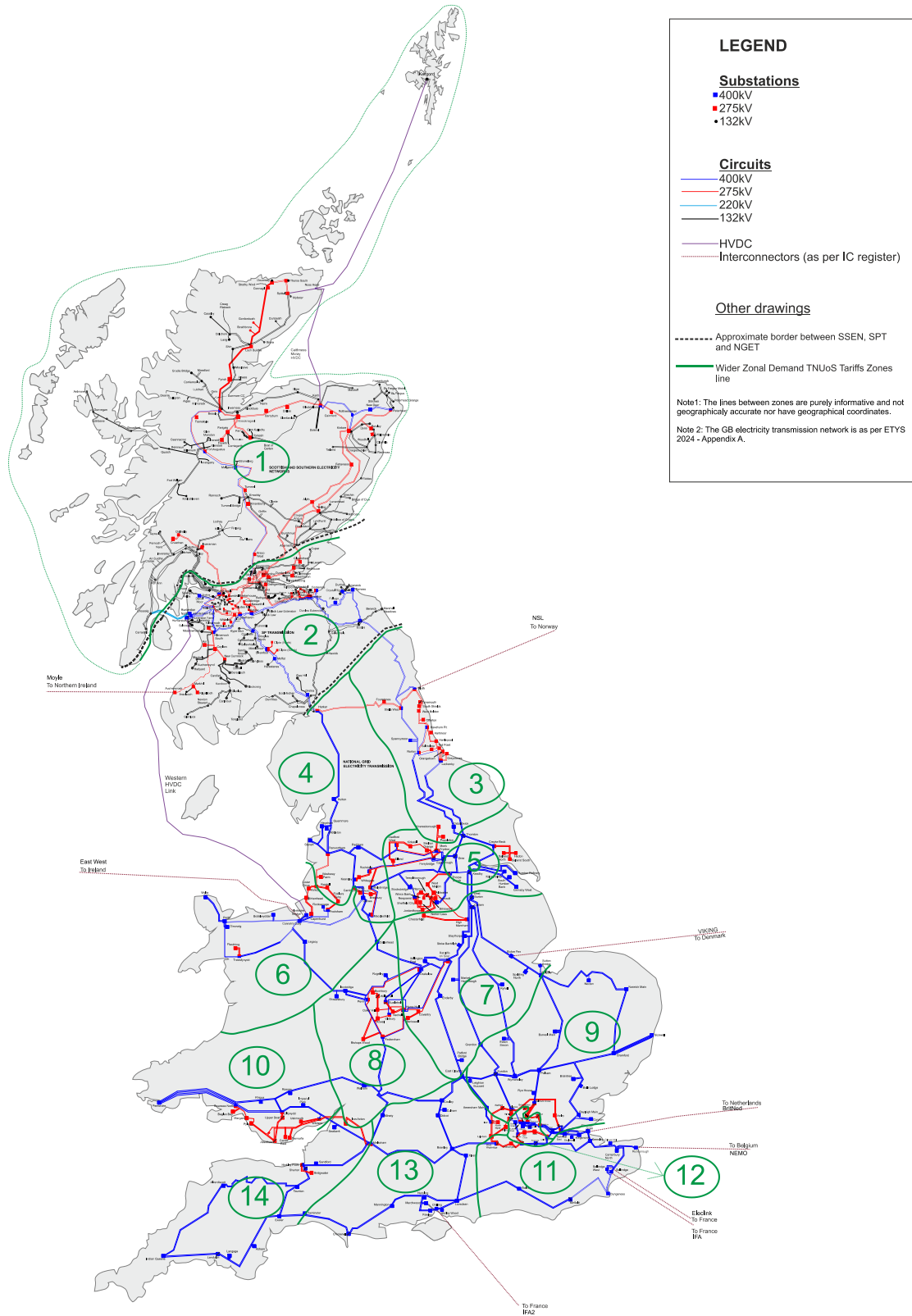


Geographical map as of 1 April 2025

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.

2027/28 TNUoS Tariff Forecast					
		April 2026	September 2026	Draft Tariffs November 2026	Final Tariffs January 2027
Methodology		Open to industry governance			
LOCATIONAL	DNO/DCC Demand Data	Initial update using previous year's data source		Week 24 updated	
	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
	Inflation	Forecast			Actual
RESIDUAL / ADJUSTMENT	OFTO Revenue <i>(part of allowed revenue)</i>	Forecast	Forecast	Forecast	From OFTOs & NESO best view
	Allowed Revenue <i>(non OFTO changes)</i>	Initial update using previous year's data source	Update financial parameters and other passthrough cost forecasts	Latest ONTO and interconnector revenue submissions, updated financial parameters and other forecasts	Latest ONTO and interconnector revenue submissions, updated financial parameters and other forecasts
	Demand Charging Bases <i>(including TDR site counts)</i>	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
	Consumption Data <i>(by TDR charging band)</i>	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 <i>(G/D split)</i>	Forecast	Forecast	Forecast	Generation revenue £m fixed



Document Revision History





Document Revision History

Version Number	Date of Issue	Notes
1.0	11 May 2026	Publication of Initial Forecast of TNUoS Tariffs for 2027/28

Public

National Energy System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

TNUoS.Queries@neso.energy

www.neso.energy

NESO 
National Energy
System Operator