Version 1.0

Forecast of TNUoS Tariffs for 2025/26

Electricity System Operator

July 2024

ESO

List of Tables and Figures

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 July forecast of TNUoS Tariffs for 2025/26.

Under the National Grid Electricity System Operator (ESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2025/26 on our website[1].

These tariffs will take effect from 1st April 2025, they have no impact on charging year 2024/25.

Total revenues to be recovered

The total TNUoS revenue is forecast at £5.27bn for FY25/26, (a decrease of £12.3m from the Initial forecast). This reduction is mainly due to pass-through items offset by revisions to OFTO revenue inflation and forecast OFTO Asset Transfer Dates.

Generation tariffs

The total revenue to be recovered from generators is forecast to be £1.18bn for 2025/26, an increase of £48.9m since the Initial forecast. This is mainly driven by the increase in revenue from offshore local tariffs.

The generation charging base has been updated to 99.22GW based on our best view on generation projects for 2025/26. This is an increase of 16.1GW since the Initial forecast. The average generation tariff is £11.87/kW, a decrease of £1.70/kW due to the increase in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £4.09bn for 2025/26, a £61m decrease since the Initial tariffs. The reduction in demand revenue is the result of the proportion of demand % falling since Initial forecast (78.6% compared to 77.6% now).

The impact on the end consumer is forecast to be £51.93 for FY25/26 (6.31% of the average annual electricity consumer bill), a decrease of £0.27 from the 2025/26 Initial forecast. This is due to the reduction in the average NHH tariff since the Initial forecast. 6.31% is an increase from the 5.91% in Initial 2025/26 forecast due to a reduction in the average customer bill.

In 2025/26, it is forecast that £20.25m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a decrease of £0.99m since the Initial forecast. This is due to the decrease in the average locational tariffs. The average EET is forecast at £2.71/kW, which is a decrease of £0.13/kW versus the Initial forecast.

The average gross HH demand tariff for 2025/26 is forecast to be £6.64/kW, a decrease of £1.13/kW compared to Initial forecast and the average NHH demand tariff forecast is forecast to be 0.30p/kWh, a decrease of 0.07p/kWh since the Initial forecast.

Next TNUoS tariff publication

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

Our next TNUoS tariff publication will be our Draft forecast of 2025/26 TNUoS tariffs, which will be published in November 2024.

[1] https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges

[2] https://www.nationalgrideso.com/document/301571/download

Feedback

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

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

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

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

Our contact details:

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Charging Methodology Changes

This Report

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

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

This section summarises any key changes to the methodology.

Charging methodology changes

CMP411: 'Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies' has been approved by Ofgem for implementation on 1st April 2025.

This modification introduces a methodology for the recovery of AI costs via the AI Cost Gap Tariff, which would be applicable to the relevant offshore generator(s). CMP411 has no impact to this forecast since the methodology is only used in the event that Ofgem determine that an offshore project includes Anticipatory Investment (AI).

CMP392: 'Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation' has been approved by Ofgem for implementation on 1st April 2025.

This modification introduces additional reporting to aid in the understanding of the calculation of the Connection Exclusion. As well as publishing Guidance on the Calculation of the Charges for Physical Assets required for Connection, the following information will be published alongside our Draft and Final Tariff publications.

Project Name	Transmission Asset Name	PARC / Non-PARC	Annual Local Charge for company Transmission Asset	TEC	Tariff

This modification does not impact on the calculation of the tariffs themselves and therefore has no impact on this forecast.

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

TNUoS Task Force and electricity network charging

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

Task Force Workstream analysis and defect identification which results in proposed CUSC changes will 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 ESO website[4].

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

[4] https://www.nationalgrideso.com/industry-information/charging/charging-futures/task-forces

Generation tariffs

Wider tariffs, onshore local circuit and substation tariffs, and offshore local circuit tariffs

1. Generation tariffs summary

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

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2025/26 Initial	2025/26 July	Change since last forecast
Adjustment	- 1.825822	- 1.720165	0.105657
Average Generation Tariff*	13.576645	11.871725	- 1.704920

*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” (i.e. assets built for generation connection) are not included in the €2.50/MWh cap, whereas TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Average generation tariffs have decreased by £1.70/kW, due the 16.1GW increase in the generation charging base, compared to the Initial forecast. The generation adjustment has increased by £0.11/kW, decreasing in magnitude, to become less negative; this is because the revenue to be collected from wider tariffs is not expected to change but the charging base has increased since the Initial forecast and therefore less of an adjustment required to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

2. Generation wider tariffs

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

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

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

Annual Load Factors are explained in Appendix D.

The classifications of generator type are listed below:

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

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

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

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

Table 2 Generation wider tariffs

Generation Tariffs						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	0.767140	24.199290	17.998807	- 1.720165	15.926214	35.195250	27.168323
2	East Aberdeenshire	2.035104	15.650185	17.998807	- 1.720165	13.774536	30.051385	23.321225
3	Western Highlands	0.882159	23.694635	17.646083	- 1.720165	15.698281	34.579053	26.588504
4	Skye and Lochalsh	- 4.484755	23.694635	19.470524	- 1.720165	11.061144	31.036580	28.412945
5	Eastern Grampian and Tayside	2.934906	19.193789	13.810934	- 1.720165	14.416630	29.421017	20.727974
6	Central Grampian	2.507700	19.267244	13.908118	- 1.720165	14.057680	29.146086	20.858213
7	Argyll	0.747868	17.381538	23.561848	- 1.720165	15.405057	35.625705	29.663375
8	The Trossachs	1.501412	17.381538	11.378600	- 1.720165	11.285302	24.196001	17.480127
9	Stirlingshire and Fife	0.258989	17.299288	11.311616	- 1.720165	9.983186	22.824906	17.376131
10	South West Scotlands	- 0.312260	16.610916	10.903369	- 1.720165	8.973289	21.329131	16.658116
11	Lothian and Borders	0.063323	16.610916	5.367139	- 1.720165	7.134380	16.168484	11.121886
12	Solway and Cheviot	- 0.759600	11.460976	6.956740	- 1.720165	4.887321	13.072707	10.394014
13	North East England	0.882970	7.935695	4.112796	- 1.720165	3.982201	9.227372	5.963694
14	North Lancashire and The Lakes	- 0.980770	7.935695	1.969434	- 1.720165	1.261117	5.220270	3.820332
15	South Lancashire, Yorkshire and Humber	1.604810	4.122913	0.601244	- 1.720165	1.774308	3.578074	0.736390
16	North Midlands and North Wales	0.461262	2.133638	0.070052	- 1.720165	- 0.377427	0.411378	- 0.689976
17	South Lincolnshire and North Norfolk	0.552436	3.577227	0.070052	- 1.720165	0.291183	1.585243	- 0.040361
18	Mid Wales and The Midlands	- 0.100469	3.002048	0.070052	- 1.720165	- 0.591794	0.500954	- 0.299191
19	Anglesey and Snowdon	3.073810	2.218004	0.070052	- 1.720165	2.268867	3.087200	- 0.652011
20	Pembrokeshire	7.671526	- 10.710664	-	- 1.720165	1.667095	- 2.081637	- 6.539964
21	South Wales & Gloucester	4.450094	- 10.479758	-	- 1.720165	- 1.461974	- 5.129890	- 6.436056
22	Cotswold	4.131219	- 1.043179	- 6.004530	- 1.720165	- 0.408030	- 4.375860	- 8.194126
23	Central London	- 2.858980	- 1.043179	- 0.407270	- 1.720165	- 5.159325	- 5.768799	- 2.596866
24	Essex and Kent	0.706495	- 1.043179	-	- 1.720165	- 1.430942	- 1.796054	- 2.189596
25	Oxfordshire, Surrey and Sussex	0.186690	- 4.524955	-	- 1.720165	- 3.343457	- 4.927191	- 3.756395
26	Somerset and Wessex	3.535480	- 5.403223	-	- 1.720165	- 0.345974	- 2.237102	- 4.151615
27	West Devon and Cornwall	4.538090	- 9.784964	-	- 1.720165	- 1.096061	- 4.520798	- 6.123399

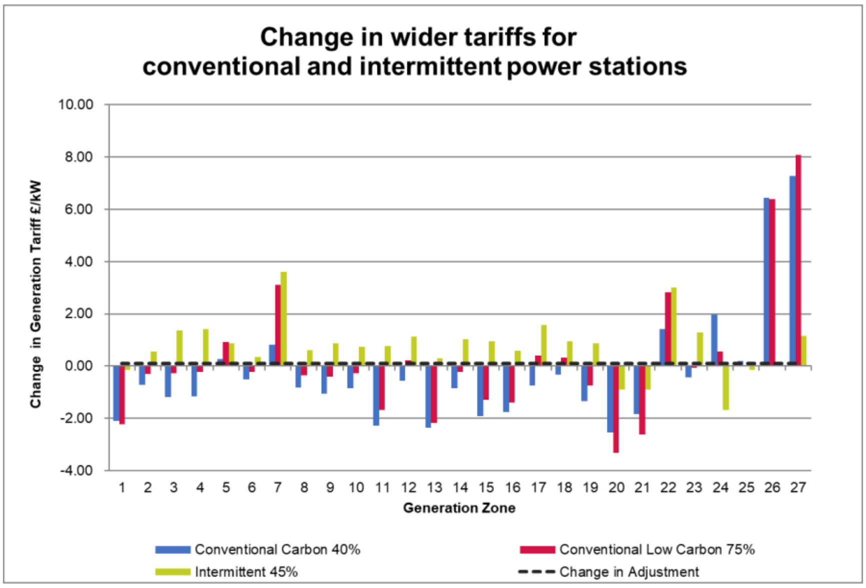
3. Changes to wider tariffs since the Initial Forecast

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

Table 3 Generation wider tariff changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			Change in Adjustment
		2025/26 Initial	2025/26 July	Change	2025/26 Initial	2025/26 July	Change	2025/26 Initial	2025/26 July	Change	
1	North Scotland	18.018479	15.926214	-2.092265	37.431128	35.195250	-2.235879	27.315513	27.168323	-0.147191	0.105657
2	East Aberdeenshire	14.486676	13.774536	-0.712140	30.350827	30.051385	-0.299442	22.753157	23.321225	0.568068	0.105657
3	Western Highlands	16.871768	15.698281	-1.173487	34.850853	34.579053	-0.271800	25.220229	26.588504	1.368275	0.105657
4	Skye and Lochalsh	12.220918	11.061144	-1.159775	31.266098	31.036580	-0.229518	26.997054	28.412945	1.415891	0.105657
5	Eastern Grampian and Tayside	14.140006	14.416630	0.276624	28.506259	29.421017	0.914758	19.847999	20.727974	0.879975	0.105657
6	Central Grampian	14.577595	14.057680	-0.519915	29.377108	29.146086	-0.231022	20.513721	20.858213	0.344491	0.105657
7	Argyll	14.581682	15.405057	0.823375	32.525240	35.625705	3.100465	26.058642	29.663375	3.604733	0.105657
8	The Trossachs	12.109832	11.285302	-0.824529	24.541484	24.196001	-0.345483	16.872133	17.480127	0.607994	0.105657
9	Stirlingshire and Fife	11.039444	9.983186	-1.056258	23.232429	22.824906	-0.407523	16.517243	17.376131	0.858888	0.105657
10	South West Scotlands	9.814849	8.973289	-0.841560	21.597295	21.329131	-0.268164	15.920529	16.658116	0.737587	0.105657
11	Lothian and Borders	9.410046	7.134380	-2.275666	17.846318	16.168484	-1.677834	10.343572	11.121886	0.778314	0.105657
12	Solway and Cheviot	5.443201	4.887321	-0.555880	12.848695	13.072707	0.224012	9.254680	10.394014	1.139335	0.105657
13	North East England	6.346885	3.982201	-2.364683	11.403092	9.227372	-2.175720	5.666786	5.963694	0.296908	0.105657
14	North Lancashire and The Lakes	2.120838	1.261117	-0.859722	5.455510	5.220270	-0.235239	2.797560	3.820332	1.022772	0.105657
15	South Lancashire, Yorkshire and Humber	3.680738	1.774308	-1.906431	4.875022	3.578074	-1.296948	-0.215637	0.736390	0.952027	0.105657
16	North Midlands and North Wales	1.380508	-0.377427	-1.757935	1.808479	0.411378	-1.397101	-1.275574	-0.689976	0.585598	0.105657
17	South Lincolnshire and North Norfolk	1.028438	0.291183	-0.737256	1.187719	1.585243	0.397525	-1.621033	-0.040361	1.580672	0.105657
18	Mid Wales and The Midlands	-0.278044	-0.591794	-0.313750	0.178126	0.500954	0.322828	-1.239319	-0.299191	0.940127	0.105657
19	Anglesey and Snowdon	3.604992	2.268867	-1.336125	3.836158	3.087200	-0.748958	-1.528608	-0.652011	0.876597	0.105657
20	Pembrokeshire	4.196305	1.667095	-2.529209	1.228542	-2.081637	-3.310179	-5.641517	-6.539964	-0.898446	0.105657
21	South Wales & Gloucester	0.386555	-1.461974	-1.848529	-2.502059	-5.129890	-2.627831	-5.539754	-6.436056	-0.896302	0.105657
22	Cotswold	-1.812209	-0.408030	1.404179	-7.199691	-4.375860	2.823831	-11.197234	-8.194126	3.003109	0.105657
23	Central London	-4.717791	-5.159325	-0.441534	-5.712397	-5.768799	-0.056402	-3.875774	-2.596866	1.278909	0.105657
24	Essex and Kent	-3.396889	-1.430942	1.965947	-2.367165	-1.796054	0.571111	-0.501891	-2.189596	-1.687704	0.105657
25	Oxfordshire, Surrey and Sussex	-3.532881	-3.343457	0.189424	-4.918694	-4.927191	-0.008497	-3.607581	-3.756395	-0.148814	0.105657
26	Somerset and Wessex	-6.784852	-0.345974	6.438878	-8.615279	-2.237102	6.378176	-4.179228	-4.151615	0.027612	0.105657
27	West Devon and Cornwall	-8.357614	-1.096061	7.261553	-12.602804	-4.520798	8.082006	-7.283924	-6.123399	1.160525	0.105657

Figure 1 Variation in generation wider zonal tariffs



Locational changes

The generation tariffs have changed since the Initial tariffs, mainly due to a revised view on the likely October contractual TEC (which will be used to set the locational elements in the final tariffs), and the increase in the adjustment tariff (which has decreased in magnitude to become less negative).

This means that there have been changes in the overall tariffs across each generation zone. Using the example ALFs[5], many zones have seen a decrease in tariffs for Conventional Carbon and Low Carbon whereas Intermittent tariffs have mostly increased due to changes in the best view of October TEC in those areas.

Changes in zones where there are more significant increases in tariffs are due to increases in the best view for the relevant technology type. In particular, increases in intermittent generation have caused increases to tariffs in Zone 7, which is sensitive to generation/demand changes due to having relatively long radial circuits; increases in Conventional Carbon and Conventional Low Carbon generation have increased expected tariffs in zones 22, 26 & 27; whereas a reduction in Conventional Carbon Generation has caused decreases in zones 20 & 21.

Adjustment tariff changes

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

The adjustment tariff has increased by £0.11/kW since the Initial forecast, decreasing in magnitude, to become less negative. This is because the revenue to be collected by the wider tariff is not expected to change, whereas the charging base is expected to increase, meaning that there is less adjustment required to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see Table 23.

Onshore local tariffs for generation

4. Onshore local substation tariffs

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

The CPIH figure used in the calculation of local substation tariffs has been updated and will be finalised once the October index is known.

Table 4 Local substation tariffs

2025/26 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.179362	0.089685	0.061860
<1320 MW	Redundancy	0.377937	0.191960	0.136303
>=1320 MW	No redundancy	-	0.263493	0.187600
>=1320 MW	Redundancy	-	0.396512	0.285190

[5] The above examples may not be representative of every generator and should only be used as a guide, as changes to ALFs can cause tariff variances to increase/decrease/reverses and the magnitude of this can fluctuate across zones and technology type.

5. Onshore local circuit tariffs

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

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

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.710400	Douglas North	0.760178	Limekilns	2.216210
Aberdeen Bay	3.344782	Dunhill	1.790315	Lochay	0.380089
Achruach	- 3.097959	Dunlaw Extension	0.528513	Luichart	0.705952
Aigas	0.845011	Dunmaglass	1.086421	Marchwood	- 0.295433
An Suidhe	- 1.152745	Edinbane	8.550110	Mark Hill	1.102320
Arecleoch	3.002765	Enoch Hill	1.661425	Middle Muir	2.850666
Arecleoch extension	3.203963	Ewe Hill	1.739963	Middleton	0.176716
Ayrshire Grid Collector	0.168914	Fallago	- 0.079769	Millennium Wind	1.959964
Beinneun Wind Farm	1.686606	Farr	4.345138	Mossford	3.743630
Benbrack	0.910102	Faw Side	10.143578	Nant	- 1.553567
Bhlaraidh Wind Farm	0.761234	Fernoch	5.354966	Necton	0.546778
Black Hill	1.918194	Ffestiniogg	0.271612	Rhigos	0.509967
Black Law	2.090489	Fife Grid Services	0.189636	Rocksavage	- 0.018346
BlackCraig Wind Farm	6.483749	Finlarig	0.380089	Saltend	- 0.019389
BlackLaw Extension	4.547359	Foyers	0.349215	Sandy Knowe	4.021617
Broken Cross	1.329002	Galawhistle	1.304972	Sanquhar II	8.644299
Clyde (North)	0.132278	Glen Kyllachy	0.570133	Scoop Hill	0.539007
Clyde (South)	0.154325	Glendoe	2.292631	Shepherds Rig	0.091395
Coalburn BESS	0.473791	Glenglass	5.720190	South Humber Bank	- 0.221748
Corriegarth	3.040711	Gordonbush	- 0.065037	Spalding	0.333393
Corriemoillie	1.984840	Griffin Wind	11.843256	St Fergus Mobil	1.215648
Coryton	0.054787	Hadyard Hill	3.420800	Stranoch	3.822544
Creag Riabhach	4.180977	Harestanes	2.850666	Strathbrora	- 0.187079
Cruachan	2.224848	Hartlepool	0.645878	Strathy Wind	2.019959
Culligran	2.160225	Invergarry	0.380089	Strathy Wood	4.180977
Cumberhead Collector	0.869982	Kergord	61.109666	Stronelairg	1.338430
Cumberhead West	4.610456	Kilgallioch	1.322784	Wester Dod	0.434991
Deanie	3.548941	Kilmarnock BESS	0.487973	Whitelee	0.132278
Dersalloch	2.801692	Kilmorack	0.154302	Whitelee Extension	0.374789
Dinorwig	2.945956	Kype Muir	1.848711		
Dorenell	2.557592	Langage	- 0.401923		

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

Table 6 Circuits subject to one-off charges

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

Offshore local tariffs for generation

6. Offshore local generation tariffs

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

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

Table 7 Offshore local tariffs for 2025/26

Offshore Generator	2025/26 Initial Tariff Component (£/kW)			2025/26 July Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	11.658323	61.590320	1.529372	11.652416	61.559113	1.528597	-0.005907	-0.031207	-0.000775
Beatrice	9.420748	25.830090	-	9.408052	25.795281	-	-0.012696	-0.034809	-
Burbo Bank Extension	14.632563	28.280261	-	14.612844	28.242150	-	-0.019719	-0.038111	-
Dudgeon	21.402436	33.580751	-	21.373594	33.535496	-	-0.028842	-0.045255	-
East Anglia 1	12.669279	53.467720	-	12.652206	53.395666	-	-0.017073	-0.072054	-
Galloper	21.908288	34.650210	-	21.878763	34.603514	-	-0.029525	-0.046696	-
Greater Gabbard	21.721877	50.266609	-	21.710871	50.241140	-	-0.011006	-0.025469	-
Gunfleet	25.370989	23.396603	4.372959	25.358134	23.384749	4.370744	-0.012855	-0.011854	-0.002215
Gwynt y mor	27.478173	27.167178	-	27.441143	27.130566	-	-0.037030	-0.036612	-
Hornsea 1A	9.780220	34.603945	-	9.767039	34.557311	-	-0.013181	-0.046634	-
Hornsea 1B	9.780220	34.603945	-	9.767039	34.557311	-	-0.013181	-0.046634	-
Hornsea 1C	9.780220	34.603945	-	9.767039	34.557311	-	-0.013181	-0.046634	-
Hornsea 2A	11.069115	37.393128	-	11.083084	37.440316	-	0.013969	0.047188	-
Hornsea 2B	11.069115	37.393128	-	11.083084	37.440316	-	0.013969	0.047188	-
Hornsea 2C	11.069115	37.393128	-	11.083084	37.440316	-	0.013969	0.047188	-
Humber Gateway	16.171058	37.101971	-	16.149266	37.051971	-	-0.021792	-0.050000	-
Lincs	22.449291	88.285386	-	22.419038	88.166410	-	-0.030253	-0.118976	-
London Array	15.234569	52.233497	-	15.214038	52.163106	-	-0.020531	-0.070391	-
Moray East	11.356280	28.445959	-	11.340976	28.407624	-	-0.015304	-0.038335	-
Ormonde	35.844282	67.000733	0.533940	35.826120	66.966785	0.533669	-0.018162	-0.033948	-0.000271
Race Bank	12.960727	35.997891	-	12.943260	35.949379	-	-0.017467	-0.048512	-
Rampion	10.587665	27.696882	-	10.573397	27.659557	-	-0.014268	-0.037325	-
Robin Rigg	-0.786737	44.656798	14.307754	-0.786338	44.634171	14.300505	0.000399	-0.022627	-0.007249
Robin Rigg West	-0.786737	44.656798	14.307754	-0.786338	44.634171	14.300505	0.000399	-0.022627	-0.007249
Sheringham Shoal	33.535110	39.496211	0.858532	33.518118	39.476199	0.858097	-0.016992	-0.020012	-0.000435
Thanet	25.608270	47.977152	1.154979	25.595295	47.952843	1.154394	-0.012975	-0.024309	-0.000585
Triton Knoll	-	-	-	10.657219	31.750835	-	10.657219	31.750835	-
Walney 1	30.958626	61.894165	-	30.942940	61.862804	-	-0.015686	-0.031361	-
Walney 2	28.802461	58.615878	-	28.787867	58.586178	-	-0.014594	-0.029700	-
Walney 3	13.313330	26.972009	-	13.295389	26.935661	-	-0.017941	-0.036348	-
Walney 4	13.313330	26.972009	-	13.295389	26.935661	-	-0.017941	-0.036348	-
West of Duddon Sands	11.906431	59.352000	-	11.890386	59.272015	-	-0.016045	-0.079985	-
Westermost Rough	24.209733	41.201889	-	24.177108	41.146364	-	-0.032625	-0.055525	-

Demand Tariffs

Half-Hourly (HH), Non-Half-Hourly (NHH) tariffs and the Embedded Export Tariff (EET)

ESO

7. Demand tariffs summary

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

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

Table 8 Summary of demand tariffs

Non-locational Banded Tariffs	2025/26 Initial	2025/26 July	Change
Average (£/site/annum)	123.469158	123.115360	- 0.353798
Unmetered (p/kWh/annum)	1.5806289	1.5591894	- 0.0214396
Demand Residual (£m)	4,038.8	3,992.7	- 46.08
HH Tariffs (Locational)	**2025/26 Initial**	**2025/26 July**	**Change**
Average Tariff (£/kW)	7.765213	6.636305	- 1.128908
EET	**2025/26 Initial**	**2025/26 July**	**Change**
Average Tariff (£/kW)	2.839169	2.706248	- 0.132921
AGIC (£/kW)	2.777296	2.789141	0.011845
Embedded Export Volume (GW)	7.484425	7.484425	-
Total Credit (£m)	21.249546	20.254709	- 0.994837
NHH Tariffs (locational)	**2025/26 Initial**	**2025/26 July**	**Change**
Average (p/kWh)	0.371266	0.304276	- 0.066990

Since the publication of the Initial forecast in April, both the average HH & NHH demand tariffs have seen an overall decrease. The main driver being the decrease in the total amount of revenue to be recovered through demand tariffs. Demand residual revenue has decreased by £46m since the Initial tariffs.

The average HH gross tariff is forecast to be £6.64/kW, a reduction of £1.13/kW compared to Initial forecast. The average NHH tariff is forecast to be 0.30p/kWh, a reduction of 0.07p/kWh compared to the Initial forecast.

The Embedded Export Volume for the July tariffs remains the same as the Initial forecast at 7.48GW. The total credit paid out to embedded generators (<100MW) is currently forecast to be £20.25m, a reduction of £0.99m. The average Embedded Export Tariff (EET) is now forecast to be £2.71/kW, a decrease of £0.13/kW compared to the Initial forecast.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	0.185399
7	East Midlands	0.076687	0.009870	2.865828
8	Midlands	2.586633	0.333620	5.375774
9	Eastern	1.333956	0.180633	4.123097
10	South Wales	7.005880	0.822447	9.795021
11	South East	4.443943	0.605997	7.233084
12	London	7.556494	0.798303	10.345635
13	Southern	6.311561	0.815929	9.100702
14	South Western	4.060896	0.562408	6.850037

8. Demand Residual Tariffs

Since the Initial forecast, we have updated the Transmission connected site count forecast to take account of the latest view of actual site counts being invoiced, including changes to non-final demand declarations and exceptional re-bandings. A breakdown of the banding thresholds, consumptions, consumption proportions and site count for the demand residual banded charges can be seen in Table TB of the published tables excel spreadsheet[6]. The residual band thresholds will remain the same for the duration of the RIIO-2 price control period.

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

Table 10 Non-Locational demand residual charges

Band		2025/26 Initial	2025/26 July	Change
Domestic	Tariff - £/Site/Day	0.137691	0.135823	-0.001868
LV_NoMIC_1		0.092819	0.091560	-0.001259
LV_NoMIC_2		0.336737	0.332169	-0.004568
LV_NoMIC_3		0.777694	0.767145	-0.010549
LV_NoMIC_4		2.315352	2.283947	-0.031405
LV1		4.161976	4.105523	-0.056453
LV2		7.080029	6.983995	-0.096034
LV3		11.288055	11.134944	-0.153111
LV4		26.322919	25.965876	-0.357043
HV1		21.883045	21.586225	-0.296820
HV2		66.034774	65.139082	-0.895692
HV3		126.716808	124.998029	-1.718779
HV4		323.999060	319.604356	-4.394704
EHV1		176.673197	174.276812	-2.396385
EHV2		889.059604	877.000450	-12.059154
EHV3		1670.100515	1647.447367	-22.653148
EHV4		4681.178212	4617.682978	-63.495234
T-Demand1		528.049641	632.567787	104.518146
T-Demand2		2143.077137	2125.129762	-17.947375
T-Demand3		4993.164837	5589.944623	596.779786
T-Demand4		15902.582985	13376.044359	-2526.538626
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		1.580629	1.559189	-0.021440
Demand Residual (£m)		**4038.81**	**3992.73**	**-46.08**

On average, Transmission Demand Residual tariffs have decreased by 1.4% since our Initial forecast, in line with the decrease in the demand revenue to be collected. Deviations away from this have been seen in the transmission connected bands are due to the updated site count forecast which now uses the latest actual data on sites being billed.

[6] Please see the Numerical data section of 'Tools and Supporting Information' for the link to the published tables excel spreadsheet.

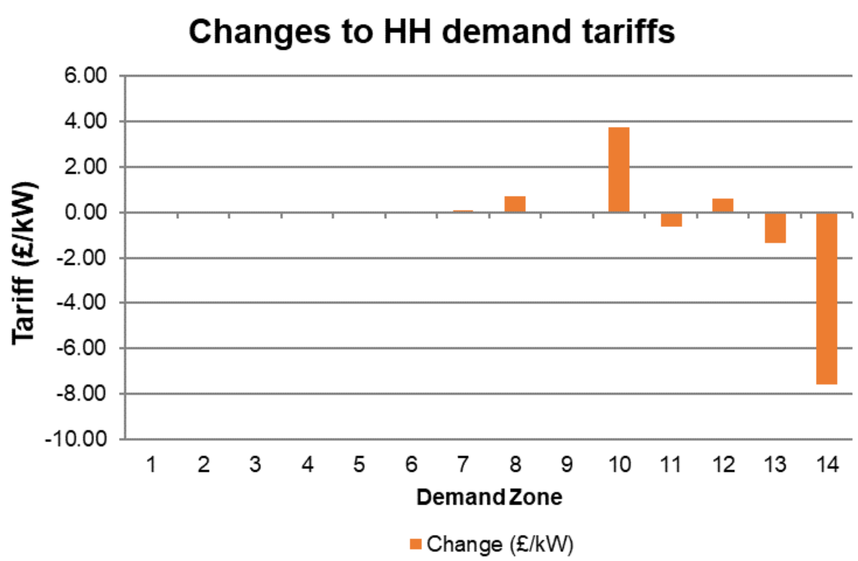
9. Half-Hourly demand tariffs

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

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2025/26 Initial (£/kW)	2025/26 July (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	0.076687	0.076687
8	Midlands	1.905747	2.586633	0.680886
9	Eastern	1.350978	1.333956	- 0.017022
10	South Wales	3.248225	7.005880	3.757655
11	South East	5.098001	4.443943	- 0.654058
12	London	6.936919	7.556494	0.619575
13	Southern	7.651333	6.311561	- 1.339772
14	South Western	11.646717	4.060896	- 7.585821

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 13. These are due to changes in the generation background which have adjusted flows within the transport model. Zone 10 has an increase of £3.76 compared to the Initial forecast, as there is approximately 0.5GW less generation. In zone 14, an extra 2GW is expected which has reduced the demand tariff by £7.59 compared to the Initial tariffs.

The forecast level of gross HH chargeable demand has increased by 0.49GW in comparison with the Initial view tariffs and is currently forecast to be 17.70GW.

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

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

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

		Demand Zone			T-connected Site		
Site Code	Site Name	DNO 1	DNO 2	DNO 3	Zonal Peak Security Tariff (£/kW)	Year Round Tariff (£/kW)	T-Connected Tariff Floored (£/kW)
MELK	MELKSHAM	13	14		-2.241137	7.427366	5.186229
BARK	BARKING	9	12		1.054406	3.390819	4.445225
WISD	WILLESDEN	9	12	13	0.619507	4.447830	5.067337

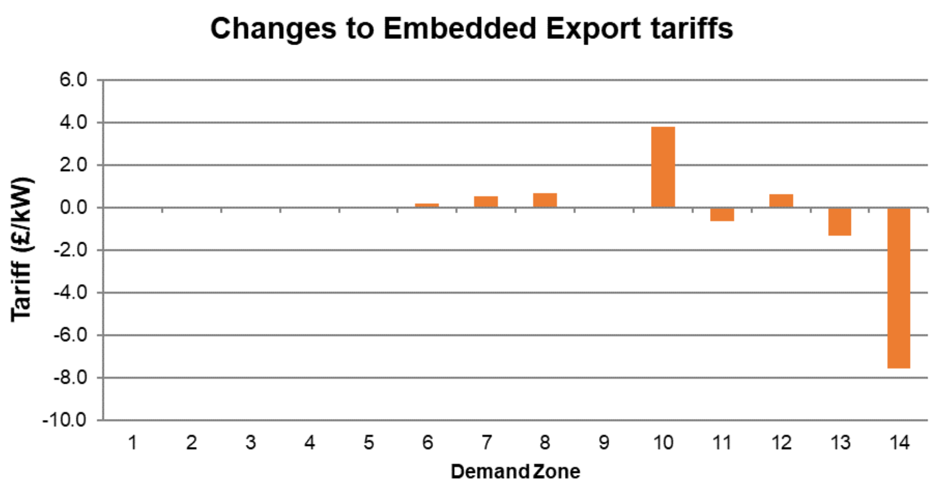
10. Embedded Export Tariffs (EET)

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

Table 13 Embedded Export Tariffs

Zone	Zone Name	2025/26 Initial (£/kW)	2025/26 July (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	0.185399	0.185399
7	East Midlands	2.334421	2.865828	0.531407
8	Midlands	4.683043	5.375774	0.692731
9	Eastern	4.128274	4.123097	- 0.005177
10	South Wales	6.025521	9.795021	3.769500
11	South East	7.875297	7.233084	- 0.642213
12	London	9.714215	10.345635	0.631420
13	Southern	10.428629	9.100702	- 1.327927
14	South Western	14.424013	6.850037	- 7.573976

Figure 3 Embedded export tariff changes



In this forecast, there has been a decrease to the average EET of £0.13/kW versus the Initial forecast. The fluctuation in tariffs across each zone is linked to the changes seen in the locational element of demand charges. Zone 10 has an increase of £3.77 compared to the Initial forecast as there is approximately 0.5GW less generation. In zone 14 an extra 2GW is expected to be added which has reduced the demand tariff by £7.57 compared to the Initial tariffs. The Embedded Export Volume has remained the same as our Initial forecast of 7.48GW.

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

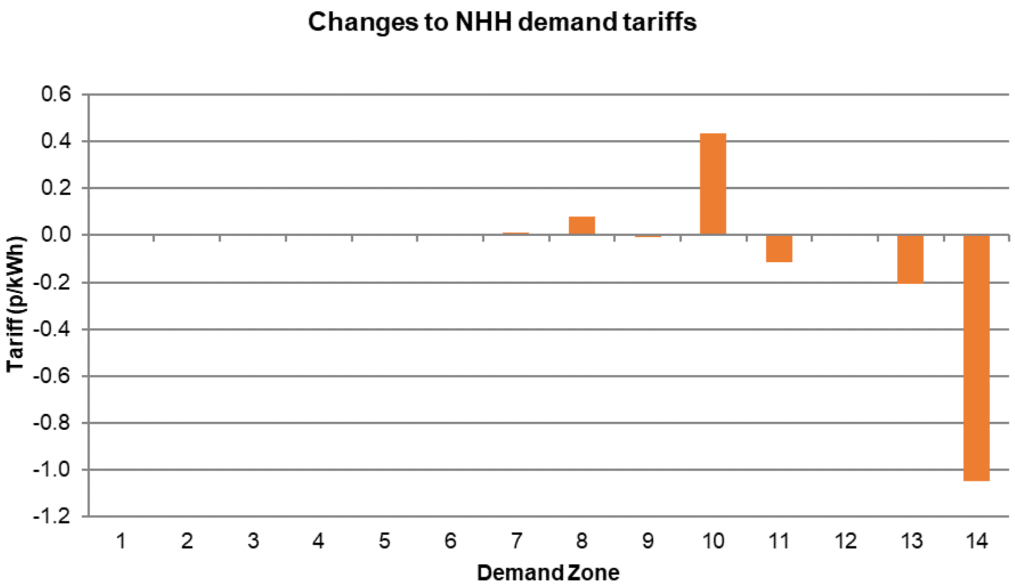
11. Non-Half-Hourly demand tariffs

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

Table 14 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2025/26 Initial (p/kWh)	2025/26 July (p/kWh)	Change (p/kWh)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	0.009870	0.009870
8	Midlands	0.254205	0.333620	0.079415
9	Eastern	0.189042	0.180633	- 0.008409
10	South Wales	0.388739	0.822447	0.433708
11	South East	0.721070	0.605997	- 0.115073
12	London	0.797668	0.798303	0.000635
13	Southern	1.022639	0.815929	- 0.206710
14	South Western	1.614174	0.562408	- 1.051766

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2025/26 is forecast to be 0.30p/kWh, a 0.07p/kWh reduction compared to the Initial forecast. As mentioned above for the HH and Embedded tariffs, the locational element of demand charges has caused fluctuations in the NHH zonal tariffs.

Overview of data inputs

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

12. Inputs affecting the locational element of tariffs

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

- Expected contracted generation (until October 2024 when it will be based on contracted TEC);
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2025/26 period, which can be found on the TEC register[7]. The contracted TEC volumes are based on the 17th June 2024 TEC register.

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

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2025/26 and liable to pay generation TNUoS charges.

Table 15 Contracted, Modelled & Chargeable TEC

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

13. Adjustments for interconnectors

When modelling flows on the transmission system in order to set locational tariffs, interconnector flows are not included in the Peak model but are included in the Year Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the calculations of chargeable TEC for either the generation or demand charging bases.

The table below reflects the contracted position of interconnectors for 2025/26 as stated in the interconnector register[7] as of 17th June 2024.

[7] See the Registers, Reports and Updates section at https://www.nationalgrideso.com/industry-information/connections/reports-and-registers

Table 16 Interconnectors

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

14. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology throughout the price control period. The 2025/26 Expansion Constant is forecast to be £18.395248/MWkm. With the approval of CMP353 the current EC value is based on the RIIO-T1 value which was set in 2013/14 and will continue to increase in-line with inflation. 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.

15. Locational onshore security factor

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

16. Onshore substation tariffs

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

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

17. Offshore local tariffs

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

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

18. Allowed revenues

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

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

Table 17 gives an overview of revenue to be recovered. For more details on the TNUoS revenue breakdown, please refer to Appendix F.

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

Table 17 Allowed revenues

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

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

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

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

The majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for PARC, however, a small part of the TNUoS onshore local charges (approximately £8.7m in this forecast) are categorised as charges associated with pre-existing assets and are therefore not PARC. This is a decrease of £3.7m to local charges associated with pre-existing assets since the Initial forecast.

Table 18 Generation and demand revenue proportions

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

The “gen cap”

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

Exchange Rate

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

Generation Output

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

Error Margin

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

Table 19 Generation revenue error margin calculation

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

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

Onshore local charges associated with Pre-existing assets

Following the implementation of CMP391 (Charges for Physical Assets Required for Connection), we have published two sets of pre-existing tariffs. These are TNUoS local tariffs associated with pre-existing circuits and pre-existing substation bays respectively.

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

Table 20 lists out the onshore local circuit tariff elements associated with pre-existing assets. Individual users who pay onshore local circuit tariffs are not affected by CMP391, as the tariffs in Table 20 are only used for the purpose of calculating the gen cap.

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

Project Name	Pre-existing local circuit tariff (£/kW)	Project Name	Pre-existing local circuit tariff (£/kW)
A'Chruach Wind Farm	0.000000	Harting Rig Wind Farm	0.000000
Glen App Windfarm	1.900444	Middle Muir Wind Farm	0.000000
Beinneun Wind Farm	0.059371	Aberdeen Offshore Wind Farm	0.000000
Afton Wind Farm	0.000000	Glen Kyllachy Wind Farm	0.570133
Benbrack wind farm	0.434991	Enoch Hill	0.000000
Blacklaw Extension	0.000000	Galawhistle Wind Farm	0.000000
Blacklaw	0.000000	Broken Cross Windfarm	1.329002
Clyde North	0.000000	Kincardine Battery Storage Facility	0.000000
Clyde South	0.000000	Limekiln	0.000000
Corriegarth	0.000000	Cumberhead West Wind Farm	0.000000
Lochluichart	0.000000	Viking Wind Farm	0.000000
Coryton	0.000000	Aikengall IIa Wind Farm	0.000000
Cruachan	0.000000	Arecleoch Windfarm Extension	2.165572
Dersalloch Wind Farm	0.000000	Crossdykes	0.000000
Dinorwig	0.000000	Cumberhead	0.000000
Edinbane Windfarm	0.000000	Kennoxhead Wind Farm Extension	2.090489
Ewe Hill	0.000000	Kype Muir	0.000000
Fallago Rig Wind Farm	0.000000	Sanquhar Wind Farm	3.801996
Carraig Gheal Wind Farm	5.354728	Chirmorie Wind Farm	0.168914
Ffestiniog	0.000000	Dalquhandy Wind Farm	0.000000
Foyers	0.000000	Douglas West	0.000000
Hartlepool	0.000000	Sandy Knowe Wind Farm	2.931734
Marchwood	0.000000	Douglas West Extension	0.000000
Pen Y Cymoedd Wind Farm	0.000000	Stranoch Wind Farm	2.701282
Rocksavage	0.000000	Twentyshilling Wind Farm	3.801996
Saltend	0.000000	Whiteside Hill Wind Farm	3.801996
Spalding	0.000000	Windy Rig Wind Farm	0.000000
Stronelairg	0.250953	Windy Standard II (Brockloch Rig) Wind Farm	0.000000
Aikengall II Windfarm	0.000000	Pencloe Windfarm	0.000000
Whitelee Extension	0.000000	Glenmuckloch Wind Farm	3.524374
Bhlaraidh Wind Farm	0.000000	Sanquhar II Wind Farm	5.720190
Dorenell Windfarm	1.278796	Windy Standard III Wind Farm	0.000000

Aggregated pre-existing TEC (MW)	13,768

Onshore local substation tariffs reflect the cost of accommodating the generator to its local substation. It is very rare for generators to have local substation tariff associated with pre-existing assets, as usually each generator has triggered its own dedicated bay at the local substation. Table 21 lists out the onshore local substation tariffs associated with pre-existing assets.

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

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.179362	37.2
Toddleburn Wind Farm	0.179362	

20. Charging bases for 2025/26

Generation

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

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

The generation charging base for 2025/26 tariffs is forecast at 99.22GW, which is an increase of 16.1GW since the Initial forecast. It is based on our internal view of what generation we expect to connect next financial year.

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

Demand

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

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

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

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

[8] Please see the Numerical data section of 'Tools and Supporting Information' for the link to the published tables excel spreadsheet.

Table 22 Charging bases

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

21. 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 2024/25 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 ESO website[9].

22. Generation adjustment and demand residual

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

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

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

Where:

A_G is the adjustment tariff (£/kW)

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

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

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

B_G is the generator charging base (GW)

A_G cannot be positive and is capped at 0.

Demand residual charges

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

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

[9] https://www.nationalgrideso.com/document/301561/download

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

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

Table 23 Residual & Adjustment components calculation

		2025/26 Tariffs			
Component		Initial	July	Draft	Final
G	Proportion of revenue recovered from generation (%)	21.38%	22.36%		
D	Proportion of revenue recovered from demand (%)	78.62%	77.64%		
R	Total TNUoS revenue (£m)	5,280.8	5,268.5		
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	448.7	488.6		
O	Revenue recovered from offshore local tariffs (£m)	766.2	796.2		
L_G	Revenue recovered from onshore local substation tariffs (£m)	13.5	15.5		
S_G	Revenue recovered from onshore local circuit tariffs (£m)	52.4	48.3		
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	12.3	8.7		
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5		
	Error Margin	31.4%	29.6%		
	Exchange Rate (€/£)	1.16	1.16		
	Total generation Output (TWh)	209.1	215.3		
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	309.2	326.8		
	Adjustment Revenue (£m)	-151.8	-170.7		
BG	Generator charging base (GW)	83.2	99.2		
AdjTariff	Generator adjusment tariff (£/kW)	-1.83	-1.72		
Gross demand residual					
R_D	Demand residual (£m)	4,038.8	3,992.7		
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	133.6	117.4		
EE	Amount to be paid to Embedded Export Tariffs (£m)	-21.2	-20.3		
B_D	Demand Gross charging base (GW)	47.4	47.4		

Tools and supporting information

ESO

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

Charging webinars

We will be hosting a webinar for the July Quarterly Forecast on Wednesday 21st August. We will be sending out a communication to those who subscribe to our updates via the ESO 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:

https://www.nationalgrideso.com/document/323581/download

This data can also be accessed via our Data Portal:

https://www.nationalgrideso.com/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@nationalgrideso.com

Appendix A: Background to TNUoS charging

ESO

Background to TNUoS charging

The ESO 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, ESO 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, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on ‘standard’ conditions, which means that they reflect the cost of new assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

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

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

Generation charging principles

Transmission connected generators (and embedded generators with TEC >= 100MW) 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.

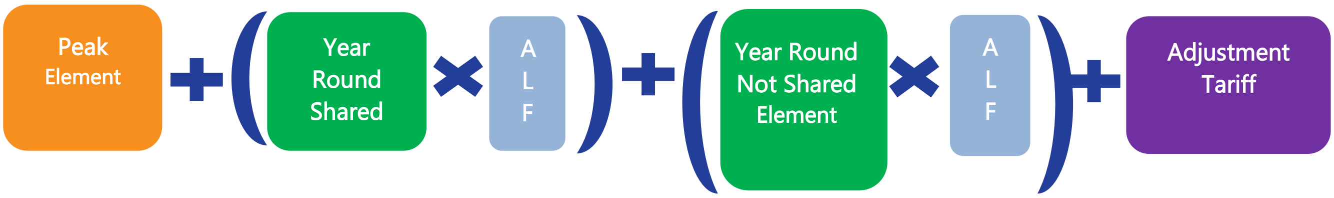
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

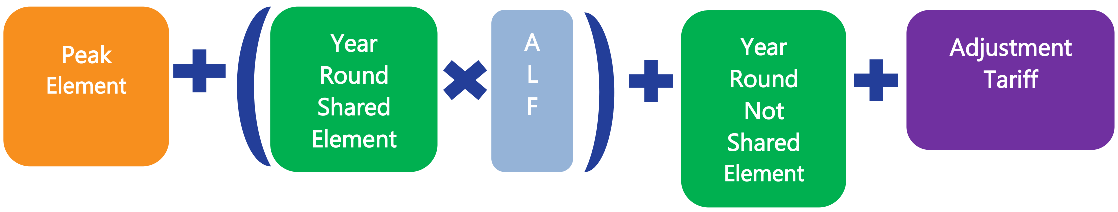
Conventional Carbon Generators

(e.g. Biomass, CHP, Coal, Gas, Pumped Storage, Battery)



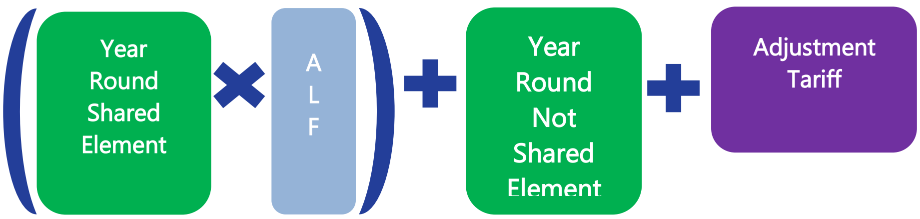
Conventional Low Carbon Generators

(e.g. Hydro, Nuclear)



Intermittent Generators

(e.g. Wind, Wave, Tidal, Solar)



The **Peak** element reflects the cost of using the system at peak times. This is only paid by conventional and peaking generators; intermittent generators do not pay this element.

The **Year Round Shared** and **Year Round Not Shared** elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular zone respectively.

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

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

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

Local substation tariffs

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

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

Local circuit tariffs

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

Embedded network system charges

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

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

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

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

The calculation for TNUoS generator monthly invoice is as follows:

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

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

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

[10] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: https://www.nationalgrideso.com/industry-information/connections

[11] Distribution network Use of System charges

Generators with negative TNUoS tariffs

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

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

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

Demand charging principles

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

HH gross demand tariffs

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

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

Embedded Export Tariffs (EET)

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

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

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

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

Embedded generators (<100MW CVA registered) will receive payment following the reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by the ESO. 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.

[12] https://www.nationalgrideso.com/industry-information/charging/triads-data
[13] https://www.nationalgrideso.com/document/130641/download
[14] https://www.nationalgrideso.com/industry-information/charging/charging-guidance

NHH demand tariffs

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

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

Demand residual tariffs

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

Appendix B: Changes and proposed changes to the charging methodology

ESO

Changes and proposed changes to the charging methodology

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

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

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

https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc/cusc-modifications

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

Table 24 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Implementation
CMP288	Explicit charging arrangements for customer delays and backfeeds	Potential impact on non-locational tariffs only	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
CMP315	Expansion Constant review	Affects TNUoS locational tariffs for generators and demand users	
CMP316/397	TNUoS Arrangements for Co-located Generation Sites	Affects TNUoS locational tariffs	
CMP375	Enduring Expansion Constant & Expansion Factor Review	Affects TNUoS locational tariffs for generators and demand users	
CMP393	Using Imports and Exports to Calculate Annual Load Factor for Electricity Storage	Change ALF calculation methodology	
CMP413	Rolling 10-year wider TNUoS generation tariffs	Seeks to introduce an obligation on the ESO to publish generation tariffs for a rolling 10-year duration	
CMP418	Refine the allocation of Static Var Compensators (SVC) costs at OFTO transfer	Seeks to remove cost of certain reactive compensation equipment from the Generators annual local offshore tariff and include it in the general TNUoS via the demand residual	
CMP424	Amendments to Scaling Factors used for Year round TNUoS charges	Seeks to introduce a mechanism which sets a lower limit on the variable generation scaling factors used for the purpose of Year Round Background tariff calculation	

CMP426	TNUoS charges for transmission circuits identified for the HND to add capacity across boundaries	Ensuring the purpose and function of circuits classified as boundary reinforcement are considered when determining the appropriate TNUoS tariff and users the costs are recovered from	
CMP430	Adjustments to TNUoS Charging from 2025 to support the Market Wide Half Hourly Settlement (MHHS) Programme	To rectify defects relating to demand locational TNUoS charging that will become apparent during the migration phase of the MHHS Programme	
Modifications directed for implementation:			
CMP392	Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation	Provides stakeholders with legal certainty and transparency of the methodology including the calculation and the output of the calculation	1st April 2025
CMP411	Introduction of Anticipatory Investment (AI) within the Section 14 charging methodologies	Introduce Anticipatory Investment (AI) and a mechanism for the recovery of AI costs within the Section 14 charging methodologies	1st April 2025

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

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

Appendix C: Breakdown of locational HH and EE tariffs

Locational components of demand tariffs

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

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

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

Demand Zone		2025/26 Initial		2025/26 July		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-1.436861	-32.106815	1.034812	-34.711603	2.471674	-2.604787
2	Southern Scotland	-1.702999	-22.947895	0.087576	-24.933077	1.790574	-1.985182
3	Northern	-3.191553	-10.209481	-0.636916	-11.668914	2.554637	-1.459433
4	North West	0.061358	-5.291851	1.534968	-6.431449	1.473610	-1.139598
5	Yorkshire	-1.953355	-2.944294	0.492905	-4.648049	2.446260	-1.703755
6	N Wales & Mersey	-1.127114	-1.741451	0.263436	-2.867178	1.390550	-1.125727
7	East Midlands	-1.742533	1.299658	-0.025789	0.102476	1.716744	-1.197182
8	Midlands	-1.067803	2.973551	0.111739	2.474894	1.179542	-0.498657
9	Eastern	0.320322	1.030656	0.382478	0.951478	0.062156	-0.079179
10	South Wales	-5.526038	8.774264	-3.986884	10.992764	1.539154	2.218500
11	South East	3.565439	1.532562	-0.385751	4.829694	-3.951190	3.297132
12	London	4.512870	2.424049	1.726334	5.830160	-2.786536	3.406111
13	Southern	1.757727	5.893606	-0.250290	6.561851	-2.008017	0.668245
14	South Western	1.079496	10.567222	-4.231984	8.292880	-5.311480	-2.274341

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

Demand Zone		2025/26 Initial		2025/26 July		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-33.543676	2.777296	-33.676790	2.789141	-0.133114	0.011845
2	Southern Scotland	-24.650894	2.777296	-24.845502	2.789141	-0.194608	0.011845
3	Northern	-13.401034	2.777296	-12.305830	2.789141	1.095204	0.011845
4	North West	-5.230494	2.777296	-4.896481	2.789141	0.334012	0.011845
5	Yorkshire	-4.897649	2.777296	-4.155143	2.789141	0.742506	0.011845
6	N Wales & Mersey	-2.868565	2.777296	-2.603742	2.789141	0.264823	0.011845
7	East Midlands	-0.442875	2.777296	0.076687	2.789141	0.519562	0.011845
8	Midlands	1.905747	2.777296	2.586633	2.789141	0.680885	0.011845
9	Eastern	1.350978	2.777296	1.333956	2.789141	-0.017022	0.011845
10	South Wales	3.248225	2.777296	7.005880	2.789141	3.757654	0.011845
11	South East	5.098001	2.777296	4.443943	2.789141	-0.654058	0.011845
12	London	6.936919	2.777296	7.556494	2.789141	0.619575	0.011845
13	Southern	7.651333	2.777296	6.311561	2.789141	-1.339772	0.011845
14	South Western	11.646717	2.777296	4.060896	2.789141	-7.585821	0.011845

Appendix D: Annual Load Factors

ESO

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 2024/25 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2018/19 to 2022/23. Generators which commissioned after 1 April 2020 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is incorporated to create three complete years from which the ALF can be calculated. Generators expected to commission during 2025/26 also use the Generic ALF (in whole or in combination with their actual data) until they have three complete years' worth of operational data to use in the calculations.

The specific and generic ALFs that will apply to the 2025/26 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2024. The specific and generic ALFs, as used in this forecast, are published here, with specific ALFs in excel format here.

Generic ALFs

Table 27 Generic ALFs

Technology	Generic ALF
Battery	1.6301%
Biomass	45.5650%
CCGT_CHP	49.4274%
Coal	16.3291%
Gas_Oil	0.4504%
Hydro	40.4462%
Nuclear	61.9265%
Offshore_Wind	46.7794%
Onshore_Wind	38.6821%
Pumped_Storage	8.3570%
Reactive_Compensation	0.0000%
Solar	10.9000%
Tidal	12.6000%
Wave	2.9000%

Please note: ALF figures for Wave, Tidal and Solar technology are generic figures published by BEIS due to no metered data being available.

These Generic ALFs are calculated in accordance with CUSC 14.15.111.

Appendix E: Contracted generation

ESO

The contracted TEC volumes are used to set locational tariffs; however, in the initial forecast and quarterly forecast we 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 will be fixed using the TEC register as of 31 October 2024, as stated by the CUSC 14.15.6 and no further changes to Contracted TEC will be made.

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

Table 28 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Beechgreen Energyfarm	50	BURW40	18
Breach Solar Farm	49.995	BURW40	18
Bredbury	50	BRED20	16
Clash Gour	-210	CLGO20	1
Dogger Bank Project A	1200	LACK40	13
East Anglia One North	-860	FRIS40	18
East Anglia Two	-860	BRFO40	18
King's Lynn 'B' Power Station	-1700	KLYN40	17
Ratcliffe-on-Soar	-50	RATS40	18
Richborough 1	50	RICH40	24
Richborough 2	50	RICH40	24
Rowan Wind Energyfarm	90.8	CRSS10	7

Appendix F: Transmission company revenues

ESO

Transmission Owner revenue forecasts

The revenue forecast has been based on Onshore and Offshore TOs' January 2024 submissions. The 2025/26 revenue forecast will be updated later this year ahead of the Draft forecast and finalised by January Final Tariffs based on Onshore and Offshore TOs' 25/26 final submissions. In addition, there are some pass-through items that are to be collected by ESO via TNUoS charges, including the Strategic Innovation Fund (SIF) and contributions made from interconnectors.

Revenue for offshore networks is included with forecasts by ESO 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. ESO and TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither ESO 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.

ESO TNUoS revenue pass-through items forecasts

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

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

Since the Initial forecast, there has been a reduction in pass-through items (see Table 29), primarily through a change in the Adjustment Term (-£40.8m). These values will be updated again in the November Draft forecast.

Table 29 ESO revenue breakdown

	NGESO TNUoS Other Pass-Through			
Term	Initial Forecast	July Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.7	0.67		
Network Innovation Competition Fund (NICFt)	0.0	0.00		
Strategic Innovation Fund (SIFt)	85.0	85.01		
The Adjustment Term (ADJt)	0.0	-40.75		
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	946.3	982.73		
Interconnectors CACM Cost Recovery (ICPt)	0.0	0.00		
Site Specific Charges Discrepancy (DISt)	0.0	0.00		
Termination Sums (TSt)	0.0	0.00		
NGET revenue pas-through (NGETTOt)*	2502.8	2,502.79		
SPT revenue pass-through (TSPt)	502.9	502.87		
SHETL revenue pass-through (TSHt)	1197.3	1,197.29		
ESO Bad debt (BDt)	3.1	0.03		
ESO other pass-through items (LFt + ITCt etc)	42.7	37.88		
ESO legacy adjustment (LARt)	0.0	0.00		
Total	**5,280.77**	**5,268.50**		

Onshore TOs (NGET, SPT and SHET) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) provided us with their final revenue breakdown in January as required by STCP 24-1. There have been no changes in TO revenue pass through items since the Initial forecast. These figures will be updated for the November Draft forecast.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2025/26 is forecast to be £1.02bn, an increase of £36.4m since the Initial forecast. Revenues have been adjusted using the latest RPI and CPI data (as part of the calculation of each OFTO's inflation term, as defined in the relevant OFTO licence).

Interconnector adjustment

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

There have been no updates to the Interconnector Adjustment forecast since January, however we expect interconnectors will notify us with the latest adjustment figures by October, which will be included in the Draft forecast.

Table 30 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	372.27	372.27		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,952.30	1,952.30		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**2,565.33**	**2,565.33**		
SONIA	B1	It-1	4.99%	4.99%		
Allowed Revenue	B2	ARt-1	2,022.91	2,022.91		
Recovered Revenue	B4	RRt-1	2,022.91	2,022.91		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	-62.54	-62.54		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**-62.54**	**-62.54**		
Site Rental Charges			**0.00**	**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**2,502.79**	**2,502.79**		

Table 31 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	372.27	372.27		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	392.65	392.65		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**515.94**	**515.94**		
SONIA	B1	It-1	4.99%	4.99%		
Allowed Revenue	B2	ARt-1	0.00	0.00		
Recovered Revenue	B4	RRt-1	0.00	0.00		
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	-13.17	-13.17		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.09	0.09		
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**-13.08**	**-13.08**		
Site Rental Charges				**0.00**		
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**502.87**	**502.87**		

Table 32 SHET revenue breakdown

Transmission Revenue Forecast			SHE Transmission			
			Initial Forecast	July Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	372.27	372.27		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	898.91	898.91		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**1,181.18**	**1,181.18**		
SONIA	B1	It-1	4.99%	4.99%		
Allowed Revenue	B2	ARt-1	781.07	781.07		
Recovered Revenue	B4	RRt-1	781.07	781.07		
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	16.12	16.12		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00		
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**16.12**	**16.12**		
Site Rental Charges				**0.00**		
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**1,197.29**	**1,197.29**		

Table 33 Offshore revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="5">Year</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2021/22</th><th>2022/23</th><th>2023/24</th><th>2024/25</th><th>2025/26</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>6.7</td><td>7.0</td><td>7.8</td><td>8.5</td><td>8.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>8.4</td><td>8.7</td><td>9.7</td><td>10.7</td><td>11.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>15.3</td><td>15.6</td><td>17.8</td><td>19.4</td><td>20.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>9.4</td><td>9.8</td><td>10.9</td><td>12.0</td><td>12.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>15.1</td><td>16.3</td><td>18.3</td><td>20.0</td><td>20.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>23.4</td><td>24.2</td><td>26.7</td><td>29.5</td><td>30.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>14.1</td><td>14.7</td><td>16.2</td><td>17.9</td><td>18.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>32.1</td><td>33.2</td><td>37.0</td><td>38.8</td><td>40.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>44.7</td><td>46.8</td><td>52.6</td><td>57.3</td><td>58.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td>20.8</td><td>21.6</td><td>24.0</td><td>26.3</td><td>27.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>30.0</td><td>32.5</td><td>34.0</td><td>40.9</td><td>40.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>32.9</td><td>39.8</td><td>37.6</td><td>37.4</td><td>39.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td>25.3</td><td>25.5</td><td>28.5</td><td>30.3</td><td>32.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>14.4</td><td>13.3</td><td>15.0</td><td>16.6</td><td>16.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>14.1</td><td>14.7</td><td>16.5</td><td>18.0</td><td>18.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Burbo Bank Extension</td><td>14.1</td><td>14.7</td><td>16.4</td><td>17.7</td><td>18.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Dudgeon</td><td>19.6</td><td>20.8</td><td>22.6</td><td>24.9</td><td>26.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Race Bank</td><td>27.4</td><td>28.9</td><td>32.5</td><td>35.4</td><td>36.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Galloper</td><td>17.1</td><td>17.8</td><td>20.1</td><td>21.9</td><td>22.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 3</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>17.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 4</td><td>13.5</td><td>14.1</td><td>15.9</td><td>17.3</td><td>17.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1A</td><td rowspan="5">137.1</td><td>18.4</td><td>20.6</td><td>22.2</td><td>23.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1B</td><td>18.4</td><td>20.6</td><td>22.2</td><td>23.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 1C</td><td>18.4</td><td>20.6</td><td>22.2</td><td>23.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Beatrice</td><td>21.1</td><td>24.4</td><td>25.7</td><td>27.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Rampion</td><td>15.5</td><td>17.4</td><td>19.7</td><td>20.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>East Anglia 1</td><td></td><td rowspan="6">68.3</td><td>47.4</td><td>51.8</td><td>54.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2A</td><td></td><td rowspan="5">138.7</td><td>25.3</td><td>27.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2B</td><td></td><td>25.3</td><td>27.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Hornsea 2C</td><td></td><td>25.3</td><td>27.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Triton Knoll</td><td></td><td>41.3</td><td>42.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Moray East</td><td></td><td>28.2</td><td>48.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2024/25</td><td></td><td></td><td></td><td>52.6</td><td>91.0</td><td>ESO Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2025/26</td><td></td><td></td><td></td><td></td><td>49.1</td><td>ESO Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>549.0</td><td>594.3</td><td>765.6</td><td>879.8</td><td>1,019.8</td><td></td></tr>
</table>

Notes:

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

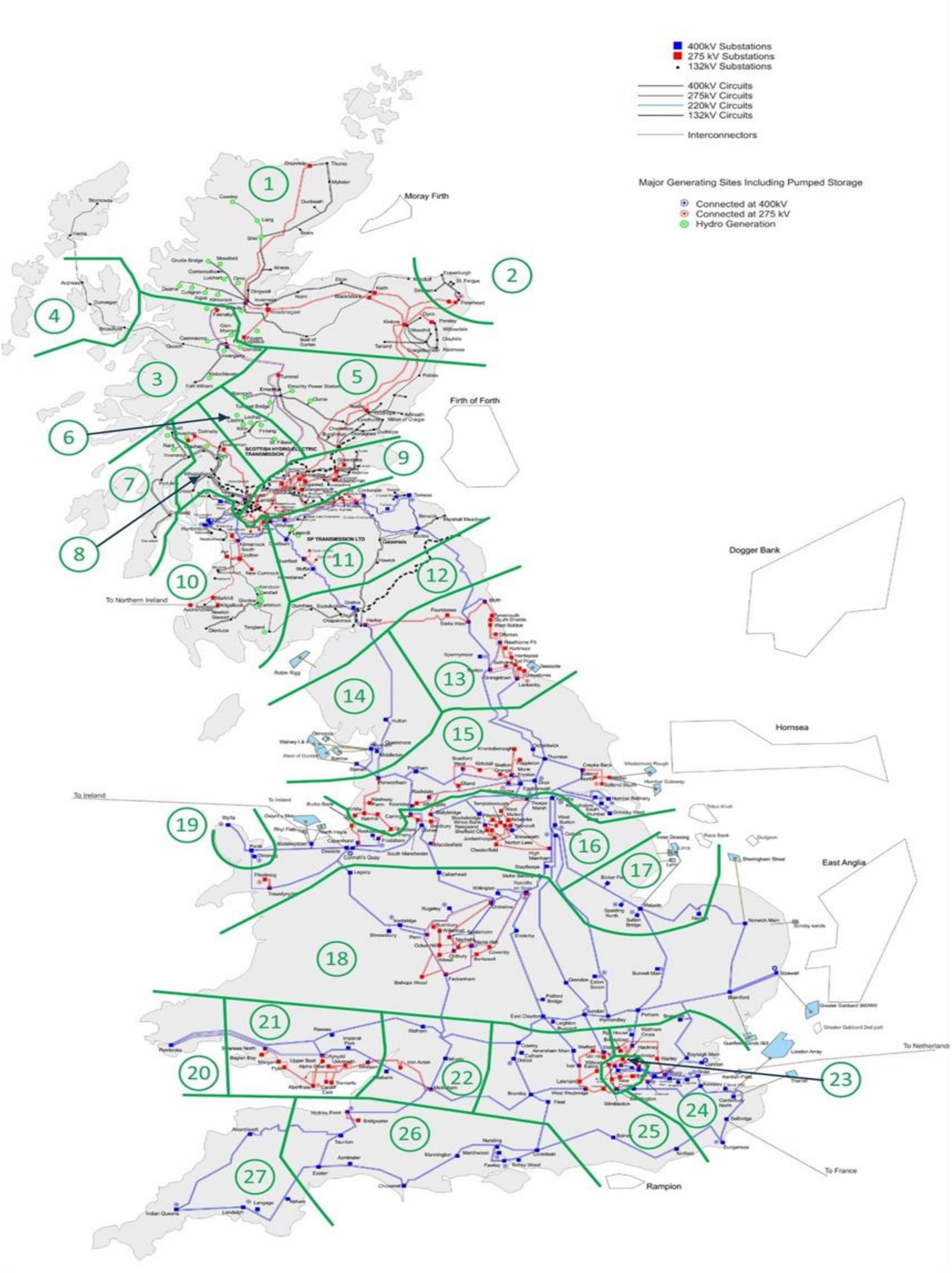
Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders.

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

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

Appendix G: Generation zones map

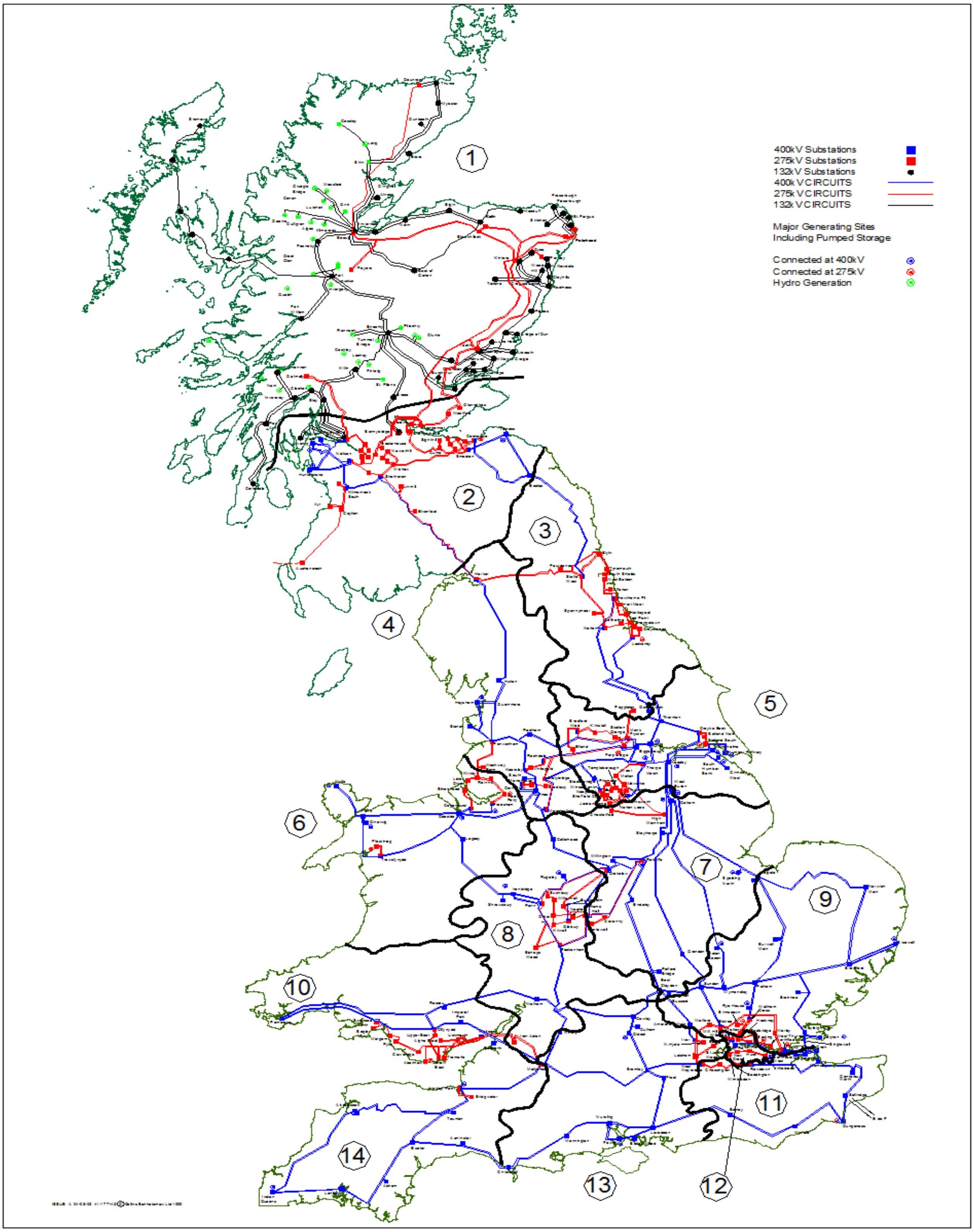
Figure A2: GB Existing Transmission System



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

Appendix H: Demand zones map

ESO


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

Appendix I: Changes to TNUoS parameters

ESO

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.

<table>
<tr><th colspan="6">2025/26 TNUoS Tariff Forecast</th></tr>
<tr><th colspan="2"></th><th>April
2024</th><th>July
2024</th><th>Draft Tariffs
November 2024</th><th>Final Tariffs
January 2025</th></tr>
<tr><td colspan="2">Methodology</td><td colspan="4">Open to industry governance</td></tr>
<tr><td rowspan="4">LOCATIONAL</td><td>DNO/DCC Demand Data</td><td colspan="2">Initial update using previous year's data source</td><td>Week 24 updated</td><td></td></tr>
<tr><td>Contracted TEC</td><td>Latest TEC Register</td><td>Latest TEC Register</td><td>TEC Register Frozen on 31 October</td><td></td></tr>
<tr><td>Network Model</td><td colspan="2">Initial update using previous year's data source (except local circuit changes which are updated quarterly)</td><td>Latest version based on ETYS</td><td></td></tr>
<tr><td>Inflation</td><td colspan="3">Forecast</td><td>Actual</td></tr>
<tr><td rowspan="8">RESIDUAL / ADJUSTMENT</td><td>OFTO Revenue (part of allowed revenue)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>From OFTOs & ESO best view</td></tr>
<tr><td>Allowed Revenue (non OFTO changes)</td><td>Initial update using previous year's data source</td><td>Update financial parameters</td><td>Latest TO forecasts</td><td>From TOs</td></tr>
<tr><td>Demand Charging Bases (including TDR site counts)</td><td>Initial update using previous year's data source</td><td>Revised forecast</td><td>Revised forecast</td><td>Revised by exception</td></tr>
<tr><td>Consumption Data (by TDR charging band)</td><td colspan="2">Previous year's data source</td><td>DNO/IDNO consumption update received</td><td></td></tr>
<tr><td>Generation Charging Base</td><td>ESO best view</td><td>ESO best view</td><td>ESO best view</td><td>ESO final best view</td></tr>
<tr><td>Generation ALFs</td><td colspan="2">Previous year's data source</td><td>Draft ALFs published</td><td>Final ALFs published</td></tr>
<tr><td>Generation Revenue (G/D split)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>Generation revenue £m fixed</td></tr>
</table>

Document Revision History

Document Revision History

Version Number	Date of Issue	Notes
1.0	31st July 2024	Publication of Quarterly Forecast of 2025/26 TNUoS Tariffs

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