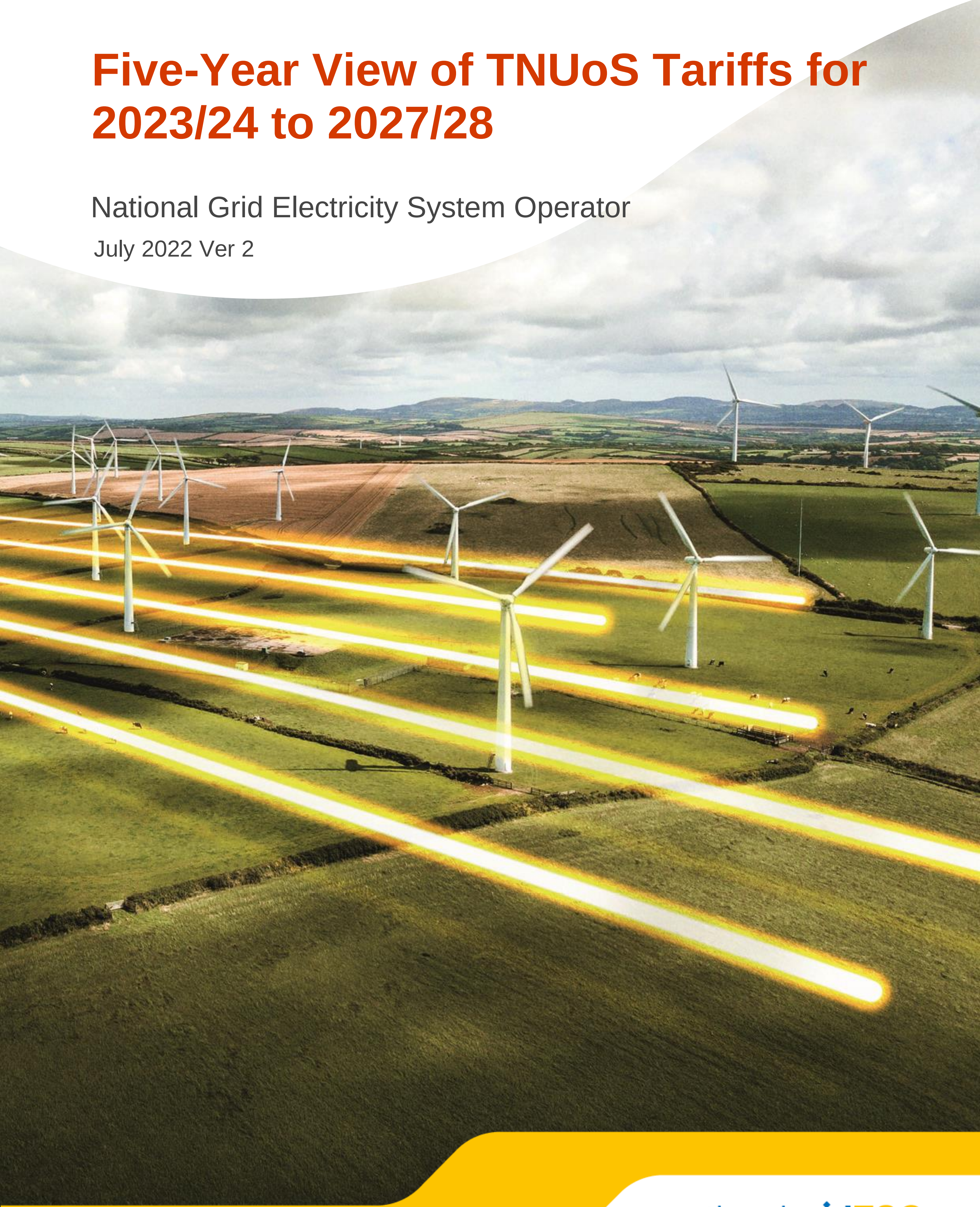
Five-Year View of TNUoS Tariffs for 2023/24 to 2027/28

National Grid Electricity System Operator

July 2022 Ver 2



Contents

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 five-year view on future TNUoS Tariffs for 2023/24 - 2027/28.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish a five-year view of future Transmission Network Use of System (TNUoS) tariffs annually on our website[1].

This report provides the forecast for the period of 2023/24 to 2027/28 and also includes the initial quarterly forecast of TNUoS tariffs for year 2023/24.

We fully appreciate that there are uncertainties with several ongoing charging methodology changes. We therefore have also included sensitivity analysis for a number of scenarios to help the industry to understand the potential implications of change, where possible. Due to a lack of data and clarity on some of the methodology changes, we cannot undertake meaningful analysis for all of the potential regulatory changes.

Regulatory Uncertainty – CMP317/327

Leave has been granted for a judicial review (JR) of the Competition and Markets Authority (CMA) decision, on the appeal to the CMA of Ofgem's 2020 CMP317/327 decision, and the proceedings are yet to be concluded.

As CMP317/327 decision is being legally challenged, there is a potential risk that our tariffs may need to be calculated under revised methodology, as a result of the JR outcome and/or any relevant Ofgem decisions. Once the JR outcome is known, we will confirm any impacts to our tariffs as soon as possible.

Transmission Demand Residual (TDR)

TDR banded charges methodology will apply from charging year 2023/24 (as per Ofgem's recent decision on CMP343[2]) and have been included in our initial tariffs for 2023/24 onwards.

Total revenues to be recovered

The total TNUoS revenue to be collected is forecast to be £3,947m for 2023/24 (an increase of £353m from the 2022/23 financial year), rising to £4,405m in 2027/28. OFTO revenue is forecast to increase steadily in the next five years whilst onshore TOs revenues also increase (by a comparatively much smaller amount) under their RIIO-2 business plan. The 2023/24 revenue forecast will be updated through the year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions and other relevant information.

Generation tariffs

The revenue to be recovered from generators is forecast to be £944.2 for 2022/23 (an increase of £102m from the 2022/23 final tariffs). It would grow to £1278.6m by 2027/28, mainly driven by the increase in offshore local charges.

The generation charging base for 2023/24 has been forecasted as 74.9GW based on our best view, an increase of 2.5GW from 2022/23. This is forecast to reach 103GW by 2027/28. This view will be further refined throughout the year. The average generation tariff for 2023/24 is forecast at £12.61/kW, an increase of £0.99/kW from the 2022/23 final tariffs. The average generation tariff is expected to increase to £12.97/kW by 2025/26, this will then drop down to £12.46/kW by 2027/28. The fluctuation in the average tariff is due to the

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

[2] https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/cmp343_minded-to_decision_consultation.pdf

change in the overall revenue to be recovered year on year vs the proportional year on year increase in the generation charging base. Where 25/26 will see proportionally a higher overall generation revenue in comparison to the generation charging base, forming a peak in the average tariff.

Demand tariffs

Revenue to be collected through demand is forecast at £3,002m for 2023/24 (an increase of £250m from 2022/23 charging year). Demand revenue will fluctuate year-on-year, with a large increase seen in 2024/25 to £3,095m. By 2027/28 revenue will reach £3,126m, see Table 23 for details. The main driver for this trend is the change in proportion in revenue to be recovered through demand versus generation and the overall increase in total revenue.

The impact on the average end consumer is forecast to be £38.13 per household in 2023/24 (6.23% of the average annual electricity consumer bill), a decrease of £0.49 compared to the equivalent figure for 2022/23. This is due to the implementation of TDR. The TNUoS charge impact is expected to increase by £1.62 to £39.75 by 2027/28 (6.5% of average annual electricity bill).

In 2023/24 it is forecast that £15.6m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), minimal change in comparison to 2022/23. The EET fluctuates marginally year on year reaching £16.9m in 2027/28. The average EET for 2023/24 remains the similar level as 2022/23 at £2.11/kW. The average EET fluctuates year on year in-line with the change in Embedded Export volumes with a low of £2.11/kW in 2023/24 and a high in 2026/27 of £2.31/kW.

With the TDR charging methodology being introduced for 2023/24, there will now be two charge types for demand. The main component will be the demand residual banded charges which will apply to both HH and NHH demand and will be a fixed tariff. The revenue to be recovered through the demand residual will be the primary driver behind the change for these banded charges. In 2023/24 the demand residual element of the overall demand revenue is forecast to be £2,926m (demand residual for 2022/23 = £2,686m). This will increase to £3,018m by 2024/25 and then steadily drop to £2,925m by 2027/28. As there are currently no forecasted elements outside of the demand residual the change in the banded tariffs will be wholly reflective of the year-on-year change in the demand residual revenue.

With the demand residual element now being removed from the current HH and NHH charges and treated separately through the TDR methodology. From April 2023 the HH and NHH tariffs as they are known today will be based solely on the locational element of demand revenue. To be now known as the locational demand charges, these tariffs will be floored at £0/kW and 0p/kWh respectively where tariffs are negative. Meaning certain demand zones will not pay a locational tariff. The average locational HH demand tariff for 2023/24 is forecast to be £4.77/kW, the average NHH demand tariff forecast is at 0.23p/kWh. By 2027/28 this will have increased to £4.93/kW for HH and 0.25p/kWh for NHH.

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts for 2023/24 is available on our website[3].

Our next TNUoS tariff publication will be the quarterly updated forecast of 2023/24 tariffs, which will be published in August 2022.

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 any CUSC modifications that are raised.

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

[3] https://www.nationalgrideso.com/document/234951/download

Charging Methodology Changes

nationalgridESO

This Report

This report contains the five-year view on TNUoS tariffs for the charging years 2023/24 – 2027/28, and the initial quarterly forecast of TNUoS for the charging year 2023/24.

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.

We understand that the TNUoS and other charging methodologies are expected to change substantially over the next few years. Because of this, we have prepared this forecast using our best view of charging parameters, the latest available information and modification workgroup progress. Additionally, whenever we can, we have provided a series of sensitivity scenarios to help customers to understand the potential implications of changes to a number of variables that impact the charging methodology.

This section summarises any key changes to the methodology.

Charging Methodology Changes

In this report we have incorporated CMP343: 'Transmission Demand Residual bandings and allocation' which has been directed for implementation with an implementation date of 1st April 2023. This delivers part of Ofgem's TCR direction concerning the Transmission Demand Residual (TDR) by creating a methodology by which the residual element of demand Transmission Network Use of System (TNUoS) tariffs can be apportioned to Half Hourly (HH) and Non-Half-Hourly (NHH) demand, and a separate methodology to determine the 'Bands' against which the residual element of demand TNUoS is levied. The demand residual banded charges will now make up majority of the TNUoS demand charge in the form of a set of annual/daily charge per site across the banding categories and thresholds. We will continue to provide further updates on potential follow-up mods as they are raised and refine the demand residual banded tariffs as we receive further information and data throughout the forecasting year.

There are also a number of 'in-flight' proposals to change the charging methodologies. These are summarised in the CUSC modifications Table 27.

Regulatory Uncertainty

Following the Targeted Charging Review (TCR), CUSC modification proposals (CMP317/327) were raised and were approved in December 2020. Please note that leave has been granted for a judicial review (JR) of the Competition and Markets Authority (CMA) decision, on the appeal to the CMA of the Ofgem's 2020 CMP317/327 decision, and the proceedings are yet to be concluded. As CMP317/327 decision is being legally challenged, there is a risk that the tariffs may need to be calculated under a revised methodology, as a result of the JR outcome and/or any relevant Ofgem decisions. Once the JR outcome is known, we will confirm if there is any impact to our tariffs as soon as possible.

Access and Forward-looking Charges Significant Code Review (Access SCR)

In January 2022, Ofgem published their minded-to position[4], outlining that they no longer intend to direct changes to TNUoS charges (including the application of these charges to small, distributed generators) under the Access SCR. The final decision is expected in Spring 2022, if there are any changes from the minded-to position we will incorporate them into our future forecast publications as necessary.

[4] https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions

TNUoS Reform

In February 2022, Ofgem published an update on the TNUoS reform programme. In their open letter[5], Ofgem stated that they will ask the ESO to launch and lead taskforces to (1) address the near-term issue with TNUoS unpredictability and cost-reflectiveness; and (2) undertake a significant programme of work looking at the longer-term purpose and structure of transmission charges, considering in particular the trade-offs between market signals, network planning and network charging signals in fostering a flexible, Net Zero energy system. An update on further details is expected at the end of March / start of April which will include the scope of the reforms. The earliest implementation date of any proposed changes will be April 2024 and therefore won't impact the 2023/24 tariffs. Once draft conclusions and/or sufficient information is available, the proposed changes will be included in future forecast publications to quantify any potential changes.

Price Control Impact on Charging Parameters

In accordance with the CUSC, at the start of each price control, various elements of the TNUoS charging methodology must be revised and updated. This forecast covers the final three years of RIIO-2 and the first 2 years of the following price control, which will commence in 2026-27. Input data for the recalculation of parameters is required from a number of sources, including the TO's and the Ofgem price control determinations, and will become available at different stages over the course of 2025-26. In this report, our assumptions are in line with the current RIIO-2 parameters, with inflation applied where applicable.

COVID-19 Impact on Demand

During 2020/21 we observed unprecedented levels of low demand in Great Britain due to the impact of COVID-19 and the corresponding periods of lockdown. As 2021/22 progressed, a return to 'normal' was seen in the demand charging bases, with the average gross demand and HH demand at Triad stabilising, as well as NHH slowly returning to similar levels forecast pre-COVID. We have not factored in any additional correction/changes to demand charging bases outside of normal forecasting process for 2023/24 onwards.

[5] https://www.ofgem.gov.uk/publications/tnuos-call-evidence-next-steps

Generation tariffs

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

nationalgridESO

1. Generation tariffs summary

This section summarises our view of generation tariffs from 2023/24 to 2027/28 and how these tariffs were calculated.

Table 1 Summary of average generation tariffs

Generation Tariffs (£/kW)	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Adjustment Tariff	- 0.228726	- 0.958471	- 2.374983	- 2.703222	- 3.928044	- 5.330796
Average Generation Tariff*	11.622336	12.608758	12.925836	12.975199	12.676928	12.458362

*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 adjustment tariff is used to ensure generation tariffs are compliant with Commission Regulation (EU) 838/2010, which has been adopted in UK legislation, 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. The implementation of CMP317/327 means that charges for local onshore and offshore tariffs are not included in the €2.50/MWh cap.

Over the next five years, it is expected that the average generation tariff will decrease from £12.61/kW in 2023/24 to £12.46/kW in 2027/28, with the peak average tariff at £12.98/kW in 2025/26. This change is mainly driven by the proportion of overall revenue that is to be recovered by generation, the increase in chargeable TEC and the change in the locational element of generation charges and the profile across zones. The adjustment tariff is expected to increase (become more negative) year-on-year from £-0.96/kW in 2023/24 to £-5.33/kW by 2027/28. This is due to the wider tariff increasing, meaning there is more of a requirement to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

2. Generation wider tariffs

The following section summarises the five-year view of wider generation tariffs from 2023/24 to 2027/28. A brief description of generation wider tariff structure can be found in Appendix A.

The wider tariffs are calculated depending on the generator type and made of four components, two of the components (Year Round Shared Element and Year Round Not Shared Element) are multiplied by the generator's specific Annual Load Factor (ALF). The ALF is explained in Appendix E.

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 (including battery storage)		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF. The 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 in 2023/24

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 40% Load Factor	Conventional Low Carbon 75% Load Factor	Intermittent 45% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	4.770666	19.798914	18.616690	-0.958471	19.178437	37.278071	26.567730
2	East Aberdeenshire	3.928442	9.826795	18.616690	-0.958471	14.347365	28.956757	22.080277
3	Western Highlands	4.069078	18.004966	17.884104	-0.958471	17.466235	34.498436	25.027868
4	Skye and Lochalsh	-0.722229	18.004966	19.521156	-0.958471	13.329749	31.344181	26.664920
5	Eastern Grampian and Tayside	5.280479	12.939468	14.938198	-0.958471	15.473074	28.964807	19.802488
6	Central Grampian	4.812561	13.428117	15.482626	-0.958471	15.418387	29.407804	20.566808
7	Argyll	3.019631	11.357897	21.173980	-0.958471	15.073911	31.753563	25.326563
8	The Trossachs	4.172931	11.357897	13.133078	-0.958471	13.010850	24.865961	17.285661
9	Stirlingshire and Fife	3.086488	10.563280	12.472038	-0.958471	11.342144	22.522515	16.267043
10	South West Scotlands	1.648835	10.638766	12.529057	-0.958471	9.957493	21.198496	16.358031
11	Lothian and Borders	4.144852	10.638766	7.628202	-0.958471	10.493168	18.793658	11.457176
12	Solway and Cheviot	1.949815	7.370188	6.977495	-0.958471	6.730417	13.496480	9.335609
13	North East England	4.459541	6.102260	4.722797	-0.958471	7.831093	12.800562	6.510343
14	North Lancashire and The Lakes	1.687661	6.102260	1.483486	-0.958471	3.763488	6.789371	3.271032
15	South Lancashire, Yorkshire and Humber	5.145839	2.604483	0.342053	-0.958471	5.365982	6.482783	0.555599
16	North Midlands and North Wales	3.865355	1.240764	-	-0.958471	3.403190	3.837457	-0.400127
17	South Lincolnshire and North Norfolk	2.255974	2.452533	-	-0.958471	2.278516	3.136903	0.145169
18	Mid Wales and The Midlands	1.311866	3.046952	-	-0.958471	1.572176	2.638609	0.412657
19	Anglesey and Snowdon	5.554899	0.914545	-	-0.958471	4.962246	5.282337	-0.546926
20	Pembrokeshire	7.593374	-7.080522	-	-0.958471	3.802694	1.324512	-4.144706
21	South Wales & Gloucester	2.935991	-7.441027	-	-0.958471	-0.998891	-3.603250	-4.306933
22	Cotswold	2.047883	3.894390	-9.702489	-0.958471	-1.233828	-5.692285	-8.908485
23	Central London	-3.598390	3.894390	-5.334569	-0.958471	-5.132933	-6.970638	-4.540565
24	Essex and Kent	-3.036906	3.894390	-	-0.958471	-2.437621	-1.074585	0.794005
25	Oxfordshire, Surrey and Sussex	-0.476161	-1.918421	-	-0.958471	-2.202000	-2.873448	-1.821760
26	Somerset and Wessex	-2.530872	-3.984128	-	-0.958471	-5.082994	-6.477439	-2.751329
27	West Devon and Cornwall	-1.505355	-6.763863	-	-0.958471	-5.169371	-7.536723	-4.002209

Table 3 Generation wider tariffs in 2024/25

Generation Tariffs 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	5.082464	15.215413	22.413152	-2.374983	17.758907	36.532193	26.885105
2	East Aberdeenshire	4.428081	7.307322	22.413152	-2.374983	13.941288	29.946742	23.326464
3	Western Highlands	4.830835	14.911445	22.141991	-2.374983	17.277226	35.781427	26.477158
4	Skye and Lochalsh	-0.059868	14.911445	23.858342	-2.374983	13.073064	32.607075	28.193509
5	Eastern Grampian and Tayside	7.129072	11.455964	18.433116	-2.374983	16.709721	31.779178	21.213317
6	Central Grampian	6.520244	11.197202	18.003441	-2.374983	15.825518	30.546604	20.667199
7	Argyll	5.291345	9.893347	22.836887	-2.374983	16.008456	33.173259	24.913910
8	The Trossachs	4.976591	9.893347	15.811309	-2.374983	12.883470	25.832927	17.888332
9	Stirlingshire and Fife	3.324640	9.268701	15.026560	-2.374983	10.667761	22.927743	16.822492
10	South West Scotlands	2.553282	9.535127	15.334389	-2.374983	10.126105	22.664033	17.250213
11	Lothian and Borders	3.608993	9.535127	9.646343	-2.374983	8.906598	18.031698	11.562167
12	Solway and Cheviot	2.615825	6.848110	8.698937	-2.374983	6.459661	14.075862	9.405604
13	North East England	4.154009	5.412258	5.111019	-2.374983	5.988337	10.949239	5.171552
14	North Lancashire and The Lakes	2.477068	5.412258	3.195625	-2.374983	3.545238	7.356904	3.256158
15	South Lancashire, Yorkshire and Humber	5.053927	2.461714	0.342987	-2.374983	3.800824	4.868217	-0.924225
16	North Midlands and North Wales	3.790718	1.675087	-0.062413	-2.374983	2.060805	2.609637	-1.683607
17	South Lincolnshire and North Norfolk	3.511205	2.426285	-0.021858	-2.374983	2.097993	2.934078	-1.305013
18	Mid Wales and The Midlands	0.471064	5.248120		-2.374983	0.195329	2.032171	-0.013329
19	Anglesey and Snowdon	6.277003	1.807024	-0.062413	-2.374983	4.599864	5.194875	-1.624235
20	Pembrokeshire	7.637402	-6.904507		-2.374983	2.500616	0.084039	-5.482011
21	South Wales & Gloucester	2.678436	-8.003902		-2.374983	-2.898108	-5.699474	-5.976739
22	Cotswold	1.974835	4.272253	-11.071419	-2.374983	-3.119814	-8.267377	-11.523888
23	Central London	-3.595014	4.272253	-5.166602	-2.374983	-6.327737	-7.932409	-5.619071
24	Essex and Kent	-2.975165	4.272253		-2.374983	-3.641247	-2.145958	-0.452469
25	Oxfordshire, Surrey and Sussex	-0.745748	-2.585696		-2.374983	-4.155009	-5.060003	-3.538546
26	Somerset and Wessex	-3.705641	-4.121932		-2.374983	-7.729397	-9.172073	-4.229852
27	West Devon and Cornwall	-2.629043	-8.833829		-2.374983	-8.537558	-11.629398	-6.350206

Table 4 Generation wider tariffs in 2025/26

Generation Tariffs 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	3.602527	17.309263	23.976775	-2.703222	17.413720	37.858027	29.062721
2	East Aberdeenshire	3.584899	8.139985	23.976775	-2.703222	13.728381	30.963441	24.936546
3	Western Highlands	3.367982	16.132039	22.563924	-2.703222	16.143145	35.327713	27.120120
4	Skye and Lochalsh	3.287998	16.132039	31.147967	-2.703222	19.496778	43.831772	35.704163
5	Eastern Grampian and Tayside	6.055409	13.329399	18.646585	-2.703222	16.142581	31.995821	21.941593
6	Central Grampian	5.473443	13.073232	18.138118	-2.703222	15.254761	30.713263	21.317850
7	Argyll	4.257023	11.881373	24.264327	-2.703222	16.012081	34.729158	26.907723
8	The Trossachs	3.921640	11.881373	15.747638	-2.703222	12.270022	25.877086	18.391034
9	Stirlingshire and Fife	2.137557	11.292386	14.851834	-2.703222	9.892023	22.755459	17.230186
10	South West Scotlands	1.963056	11.749528	15.494030	-2.703222	10.157257	23.566010	18.078096
11	Lothian and Borders	2.187443	11.749528	9.104653	-2.703222	7.825893	17.401020	11.688719
12	Solway and Cheviot	1.672886	9.046536	9.025378	-2.703222	6.198430	14.779944	10.393097
13	North East England	2.770725	7.484010	5.044415	-2.703222	5.078873	10.724926	5.708998
14	North Lancashire and The Lakes	1.481882	7.484010	2.774620	-2.703222	2.882112	7.166288	3.439203
15	South Lancashire, Yorkshire and Humber	3.792755	4.307591	-0.000311	-2.703222	2.812445	4.319915	-0.765117
16	North Midlands and North Wales	2.447541	4.402910	0.054280	-2.703222	1.527195	3.100782	-0.667632
17	South Lincolnshire and North Norfolk	2.061882	3.742806	0.007053	-2.703222	0.858604	2.172818	-1.011906
18	Mid Wales and The Midlands	0.961928	4.681522	0.030447	-2.703222	0.143494	1.800295	-0.566090
19	Anglesey and Snowdon	2.936421	5.659852	0.054280	-2.703222	2.518852	4.532368	-0.102009
20	Pembrokeshire	8.875734	-6.875135		-2.703222	3.422458	1.016161	-5.797033
21	South Wales & Gloucester	3.863960	-7.503114		-2.703222	-1.840508	-4.466598	-6.079623
22	Cotswold	1.757676	3.373120	-11.502231	-2.703222	-4.197190	-9.917937	-12.687549
23	Central London	-2.784642	3.373120	-5.142628	-2.703222	-6.195667	-8.100652	-6.327946
24	Essex and Kent	-2.147694	3.373120		-2.703222	-3.501668	-2.321076	-1.185318
25	Oxfordshire, Surrey and Sussex	-0.115246	-3.354540		-2.703222	-4.160284	-5.334373	-4.212765
26	Somerset and Wessex	-2.839933	-5.421215		-2.703222	-7.711641	-9.609066	-5.142769
27	West Devon and Cornwall	-0.102503	-10.763553		-2.703222	-7.111146	-10.878390	-7.546821

Table 5 Generation wider tariffs in 2026/27

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	2.050315	17.509652	28.193157	-3.928044	16.403395	39.447667	32.144456
2	East Aberdeenshire	3.297297	5.714113	28.193157	-3.928044	12.932161	31.847995	26.836464
3	Western Highlands	2.198147	15.702576	25.437987	-3.928044	14.726328	35.485022	28.576102
4	Skye and Lochalsh	2.138224	15.702576	32.102007	-3.928044	17.332013	42.089119	35.240122
5	Eastern Grampian and Tayside	5.434101	13.384621	21.187610	-3.928044	15.334949	32.732133	23.282645
6	Central Grampian	4.247646	13.149711	20.599741	-3.928044	13.819383	30.781626	22.589067
7	Argyll	2.067299	11.942649	30.572361	-3.928044	15.145259	37.668603	32.018509
8	The Trossachs	3.029566	11.942649	17.553963	-3.928044	10.900167	25.612472	19.000111
9	Stirlingshire and Fife	1.727206	11.367878	16.396484	-3.928044	8.904907	22.721555	17.583985
10	South West Scotlands	2.521851	11.602813	16.835664	-3.928044	9.969198	24.131581	18.128886
11	Lothian and Borders	1.948054	11.602813	10.517492	-3.928044	6.868132	17.239612	11.810714
12	Solway and Cheviot	1.455738	9.161379	9.845377	-3.928044	5.130396	14.244105	10.039954
13	North East England	2.431069	7.394929	4.491486	-3.928044	3.257591	8.540708	3.891160
14	North Lancashire and The Lakes	0.924436	7.394929	3.472297	-3.928044	1.343282	6.014886	2.871971
15	South Lancashire, Yorkshire and Humber	3.426580	5.049772	0.190209	-3.928044	1.594528	3.476074	-1.465438
16	North Midlands and North Wales	1.968442	5.076092	0.206132	-3.928044	0.153288	2.053599	-1.437671
17	South Lincolnshire and North Norfolk	2.059533	4.166108	0.092678	-3.928044	-0.164997	1.348748	-1.960617
18	Mid Wales and The Midlands	0.630891	4.227584	0.096565	-3.928044	-1.567493	-0.029900	-1.929066
19	Anglesey and Snowdon	2.578939	6.271437	0.206132	-3.928044	1.241923	3.560605	-0.899765
20	Pembrokeshire	9.099787	-6.762105	-	-3.928044	2.466901	0.100164	-6.970991
21	South Wales & Gloucester	4.057490	-6.606504	-	-3.928044	-2.513156	-4.825432	-6.900971
22	Cotswold	1.943682	2.815233	-10.869504	-3.928044	-5.206070	-10.742441	-13.530693
23	Central London	-2.379774	2.815233	-4.890260	-3.928044	-7.137829	-9.086653	-7.551449
24	Essex and Kent	-1.647704	2.815233	-	-3.928044	-4.449655	-3.464323	-2.661189
25	Oxfordshire, Surrey and Sussex	0.184005	-3.432418	-	-3.928044	-5.117006	-6.318353	-5.472632
26	Somerset and Wessex	-2.249575	-5.717603	-	-3.928044	-8.464660	-10.465821	-6.500965
27	West Devon and Cornwall	0.825716	-11.675042	-	-3.928044	-7.772345	-11.858610	-9.181813

Table 6 Generation wider tariffs in 2027/28

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	1.442833	26.358306	29.655854	-5.330796	18.517701	45.536621	36.186296
2	East Aberdeenshire	1.836816	15.738383	29.655854	-5.330796	14.663715	37.965661	31.407330
3	Western Highlands	0.902351	24.294970	27.664752	-5.330796	16.355444	41.457535	33.266693
4	Skye and Lochalsh	0.541412	24.294970	34.808656	-5.330796	18.852066	48.240500	40.410597
5	Eastern Grampian and Tayside	3.928670	20.777731	24.786577	-5.330796	16.823597	38.967749	28.805760
6	Central Grampian	2.397984	20.537088	24.504529	-5.330796	15.083835	36.974533	28.415423
7	Argyll	0.079852	18.707520	35.239689	-5.330796	16.327940	44.019385	38.327277
8	The Trossachs	0.879738	18.707520	22.340080	-5.330796	11.967982	31.919662	25.427668
9	Stirlingshire and Fife	0.372603	17.649857	21.196300	-5.330796	10.580270	29.475500	23.807940
10	South West Scotlands	1.194967	17.389078	20.928632	-5.330796	11.191255	29.834612	23.422921
11	Lothian and Borders	0.485520	17.389078	16.800204	-5.330796	8.830437	24.996737	19.294493
12	Solway and Cheviot	0.200557	13.361395	13.349765	-5.330796	5.554225	18.240572	14.031597
13	North East England	0.772572	9.260100	2.527520	-5.330796	0.156824	4.914371	1.363769
14	North Lancashire and The Lakes	-0.121275	9.260100	5.062004	-5.330796	0.276771	6.555008	3.898253
15	South Lancashire, Yorkshire and Humber	1.553324	5.945775	0.632996	-5.330796	-1.145964	1.314855	-2.022201
16	North Midlands and North Wales	0.478448	6.054686	0.691967	-5.330796	-2.153687	0.380634	-1.914220
17	South Lincolnshire and North Norfolk	-0.766182	4.796958	0.540205	-5.330796	-3.962113	-1.959055	-2.631960
18	Mid Wales and The Midlands	-0.462011	3.229464	0.385608	-5.330796	-4.346778	-2.985101	-3.491929
19	Anglesey and Snowdon	2.165943	7.196458	0.691967	-5.330796	-0.009483	2.924458	-1.400423
20	Pembrokeshire	9.449887	-5.709353	-	-5.330796	1.835350	-0.162924	-7.900005
21	South Wales & Gloucester	4.414648	-5.862839	-	-5.330796	-3.261284	-5.313277	-7.969074
22	Cotswold	3.623116	-0.466326	-6.643348	-5.330796	-4.551550	-8.700773	-12.183991
23	Central London	-0.359701	-0.466326	-4.591634	-5.330796	-7.713681	-10.631876	-10.132277
24	Essex and Kent	-0.615731	-0.466326	-	-5.330796	-6.133057	-6.296272	-5.540643
25	Oxfordshire, Surrey and Sussex	-0.690316	-5.640220	-	-5.330796	-8.277200	-10.251277	-7.868895
26	Somerset and Wessex	1.271099	-7.555463	-	-5.330796	-7.081882	-9.726294	-8.730754
27	West Devon and Cornwall	4.852565	-10.056687	-	-5.330796	-4.500906	-8.020746	-9.856305

3. Changes to wider tariffs over the five-year period

The following section provides details of the wider generation tariffs for 2023/24 to 2027/28 and explains how these could change over the next five years. 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 7 Comparison of Conventional Carbon (40%) tariffs

		Wider Generation Tariffs (£/kW)					
		Conventional Carbon 40%					
Zone	Zone Name	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1	North Scotland	18.334319	19.178437	17.758907	17.413720	16.403395	18.517701
2	East Aberdeenshire	13.842465	14.347365	13.941288	13.728381	12.932161	14.663715
3	Western Highlands	16.886331	17.466235	17.277226	16.143145	14.726328	16.355444
4	Skye and Lochalsh	12.952666	13.329749	13.073064	19.496778	17.332013	18.852066
5	Eastern Grampian and Tayside	14.887888	15.473074	16.709721	16.142581	15.334949	16.823597
6	Central Grampian	14.612130	15.418387	15.825518	15.254761	13.819383	15.083835
7	Argyll	14.451050	15.073911	16.008456	16.012081	15.145259	16.327940
8	The Trossachs	12.257952	13.010850	12.883470	12.270022	10.900167	11.967982
9	Stirlingshire and Fife	11.302339	11.342144	10.667761	9.892023	8.904907	10.580270
10	South West Scotlands	10.717503	9.957493	10.126105	10.157257	9.969198	11.191255
11	Lothian and Borders	11.146269	10.493168	8.906598	7.825893	6.868132	8.830437
12	Solway and Cheviot	7.469868	6.730417	6.459661	6.198430	5.130396	5.554225
13	North East England	8.344527	7.831093	5.988337	5.078873	3.257591	0.156824
14	North Lancashire and The Lakes	4.362370	3.763488	3.545238	2.882112	1.343282	0.276771
15	South Lancashire, Yorkshire and Humber	5.823637	5.365982	3.800824	2.812445	1.594528	-1.145964
16	North Midlands and North Wales	4.021119	3.403190	2.060805	1.527195	0.153288	-2.153687
17	South Lincolnshire and North Norfolk	3.613627	2.278516	2.097993	0.858604	-0.164997	-3.962113
18	Mid Wales and The Midlands	1.855728	1.572176	0.195329	0.143494	-1.567493	-4.346778
19	Anglesey and Snowdon	5.131182	4.962246	4.599864	2.518852	1.241923	-0.009483
20	Pembrokeshire	5.364353	3.802694	2.500616	3.422458	2.466901	1.835350
21	South Wales & Gloucester	0.910857	-0.998891	-2.898108	-1.840508	-2.513156	-3.261284
22	Cotswold	0.177437	-1.233828	-3.119814	-4.197190	-5.206070	-4.551550
23	Central London	-5.594033	-5.132933	-6.327737	-6.195667	-7.137829	-7.713681
24	Essex and Kent	-1.940300	-2.437621	-3.641247	-3.501668	-4.449655	-6.133057
25	Oxfordshire, Surrey and Sussex	-2.307572	-2.202000	-4.155009	-4.160284	-5.117006	-8.277200
26	Somerset and Wessex	-4.525667	-5.082994	-7.729397	-7.711641	-8.464660	-7.081882
27	West Devon and Cornwall	-4.227387	-5.169371	-8.537558	-7.111146	-7.772345	-4.500906

Figure 1 Wider tariffs for a Conventional Carbon (40%) generator

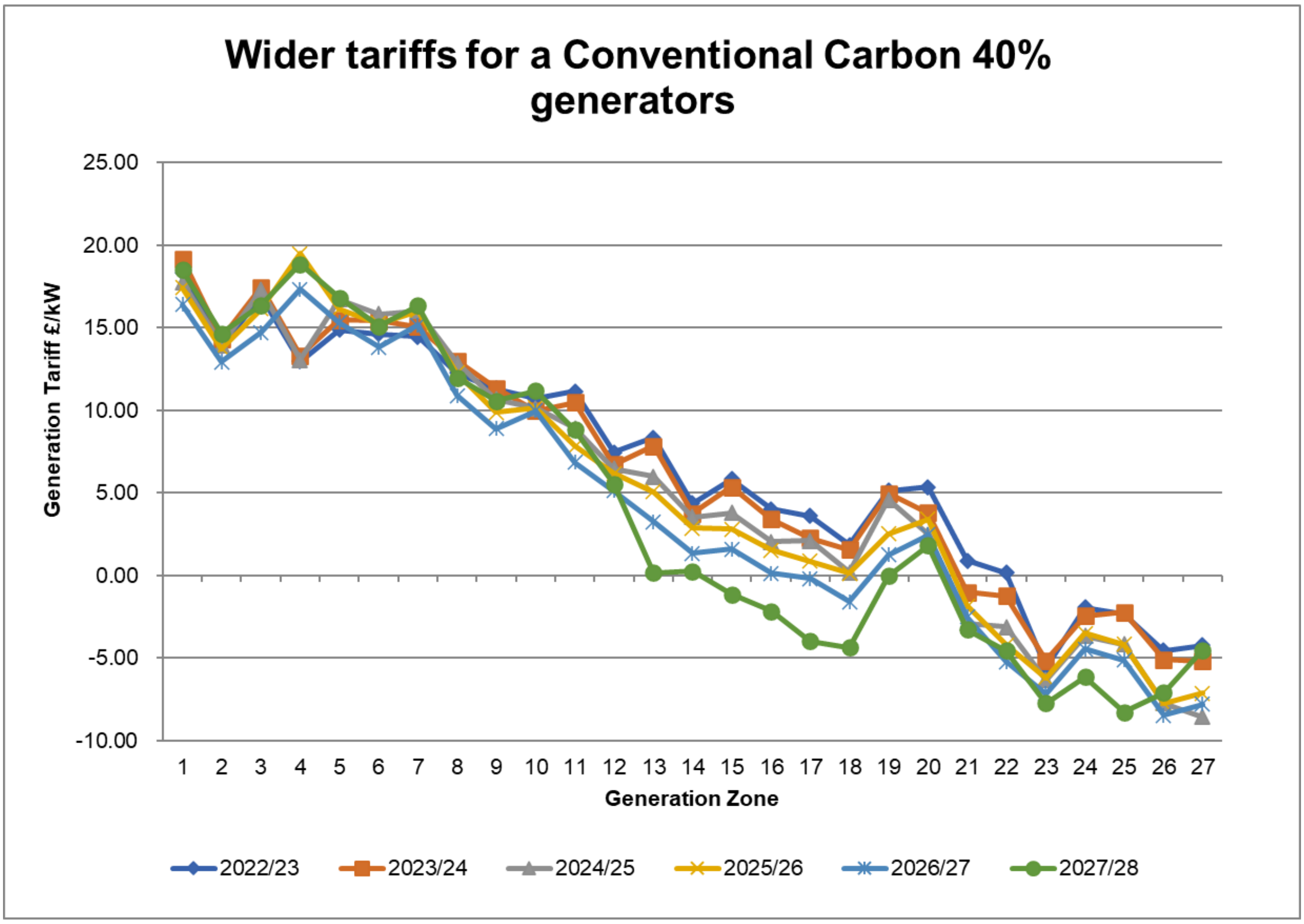


Table 8 Comparison of Conventional Low Carbon (75%) tariffs

Zone	Zone Name	Wider Generation Tariffs (£/kW) Conventional Low Carbon 75%					
		2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1	North Scotland	35.429003	37.278071	36.532193	37.858027	39.447667	45.536621
2	East Aberdeenshire	27.553705	28.956757	29.946742	30.963441	31.847995	37.965661
3	Western Highlands	32.736376	34.498436	35.781427	35.327713	35.485022	41.457535
4	Skye and Lochalsh	29.748223	31.344181	32.607075	43.831772	42.089119	48.240500
5	Eastern Grampian and Tayside	27.450930	28.964807	31.779178	31.995821	32.732133	38.967749
6	Central Grampian	27.620840	29.407804	30.546604	30.713263	30.781626	36.974533
7	Argyll	30.122542	31.753563	33.173259	34.729158	37.668603	44.019385
8	The Trossachs	23.240609	24.865961	25.832927	25.877086	25.612472	31.919662
9	Stirlingshire and Fife	21.812340	22.522515	22.927743	22.755459	22.721555	29.475500
10	South West Scotlands	21.079976	21.198496	22.664033	23.566010	24.131581	29.834612
11	Lothian and Borders	18.750219	18.793658	18.031698	17.401020	17.239612	24.996737
12	Solway and Cheviot	13.720666	13.496480	14.075862	14.779944	14.244105	18.240572
13	North East England	12.802559	12.800562	10.949239	10.724926	8.540708	4.914371
14	North Lancashire and The Lakes	7.066277	6.789371	7.356904	7.166288	6.014886	6.555008
15	South Lancashire, Yorkshire and Humber	6.584389	6.482783	4.868217	4.319915	3.476074	1.314855
16	North Midlands and North Wales	4.284149	3.837457	2.609637	3.100782	2.053599	0.380634
17	South Lincolnshire and North Norfolk	3.466921	3.136903	2.934078	2.172818	1.348748	- 1.959055
18	Mid Wales and The Midlands	2.302212	2.638609	2.032171	1.800295	- 0.029900	- 2.985101
19	Anglesey and Snowdon	5.589292	5.282337	5.194875	4.532368	3.560605	2.924458
20	Pembrokeshire	3.749223	1.324512	0.084039	1.016161	0.100164	- 0.162924
21	South Wales & Gloucester	- 0.966867	- 3.603250	- 5.699474	- 4.466598	- 4.825432	- 5.313277
22	Cotswold	- 2.941071	- 5.692285	- 8.267377	- 9.917937	- 10.742441	- 8.700773
23	Central London	- 10.411915	- 6.970638	- 7.932409	- 8.100652	- 9.086653	- 10.631876
24	Essex and Kent	- 0.862020	- 1.074585	- 2.145958	- 2.321076	- 3.464323	- 6.296272
25	Oxfordshire, Surrey and Sussex	- 2.608012	- 2.873448	- 5.060003	- 5.334373	- 6.318353	- 10.251277
26	Somerset and Wessex	- 5.272863	- 6.477439	- 9.172073	- 9.609066	- 10.465821	- 9.726294
27	West Devon and Cornwall	- 5.884536	- 7.536723	- 11.629398	- 10.878390	- 11.858610	- 8.020746

Figure 2 Wider tariffs for a Conventional Low Carbon (75%) generator

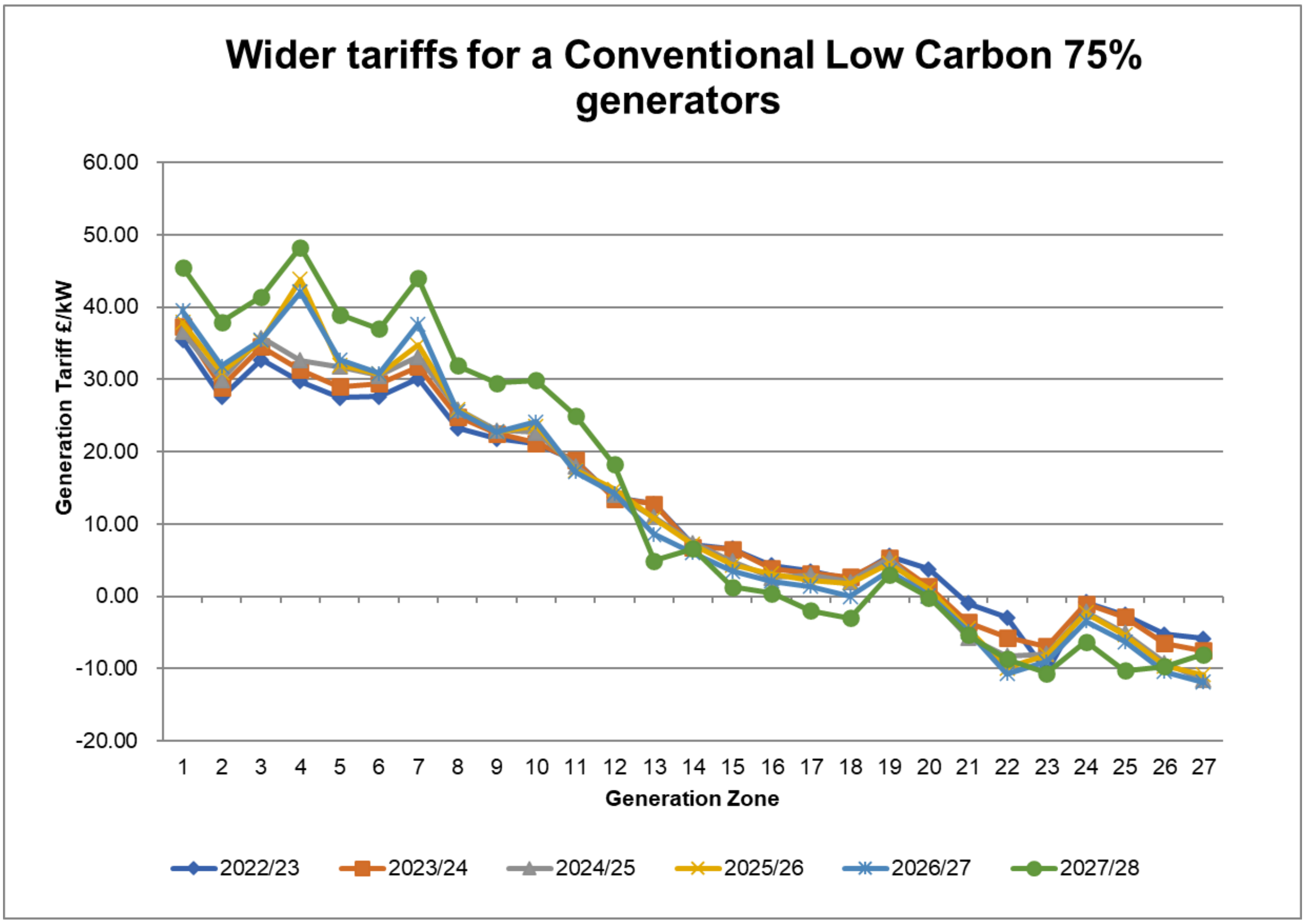
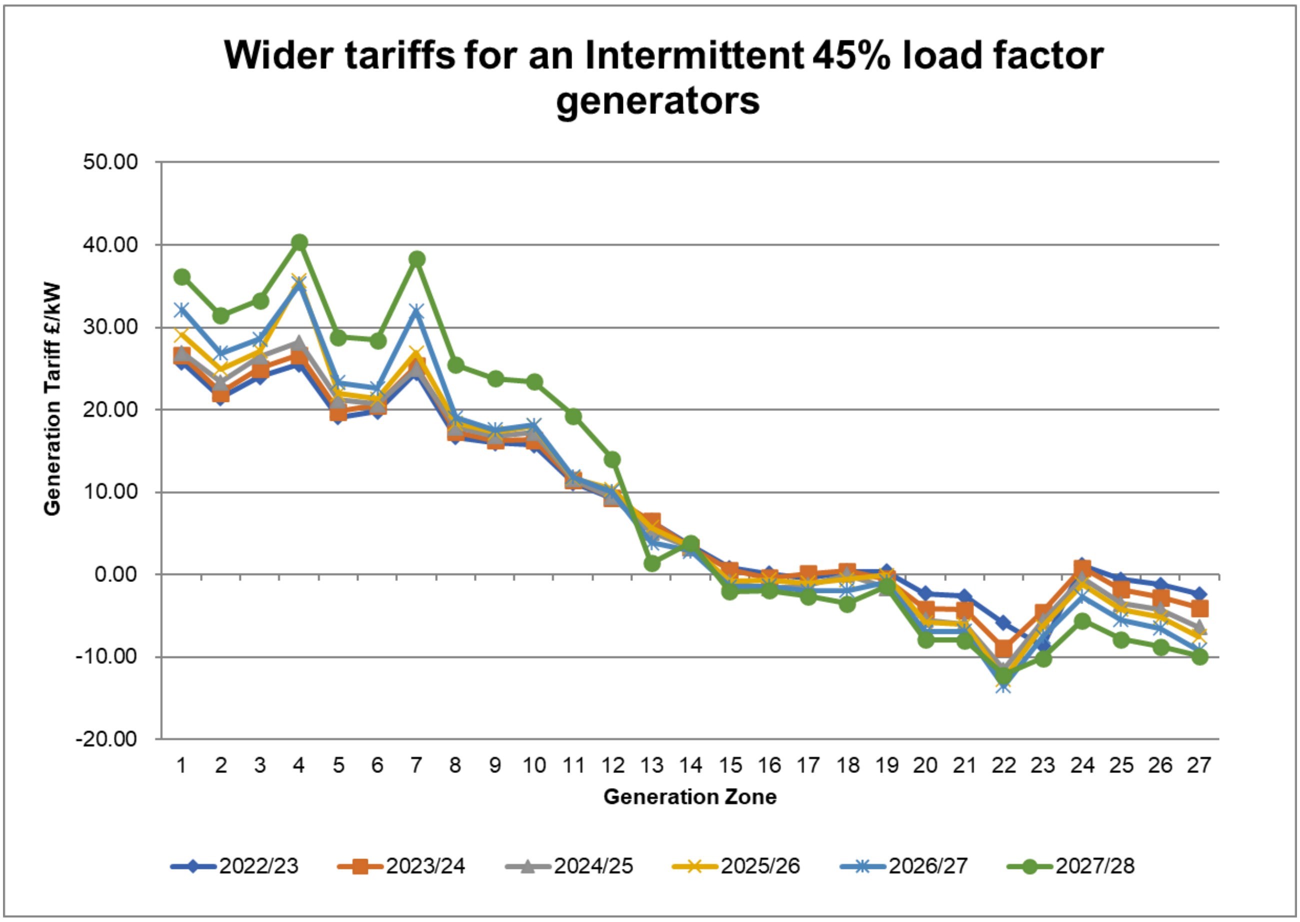


Table 9 Comparison of Intermittent (45%) tariffs

Zone	Zone Name	Wider Generation Tariffs (£/kW) Intermittent 45%					
		2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
1	North Scotland	25.759438	26.567730	26.885105	29.062721	32.144456	36.186296
2	East Aberdeenshire	21.409296	22.080277	23.326464	24.936546	26.836464	31.407330
3	Western Highlands	23.959295	25.027868	26.477158	27.120120	28.576102	33.266693
4	Skye and Lochalsh	25.535148	26.664920	28.193509	35.704163	35.240122	40.410597
5	Eastern Grampian and Tayside	19.091815	19.802488	21.213317	21.941593	23.282645	28.805760
6	Central Grampian	19.777861	20.566808	20.667199	21.317850	22.589067	28.415423
7	Argyll	24.470621	25.326563	24.913910	26.907723	32.018509	38.327277
8	The Trossachs	16.655895	17.285661	17.888332	18.391034	19.000111	25.427668
9	Stirlingshire and Fife	15.940809	16.267043	16.822492	17.230186	17.583985	23.807940
10	South West Scotlands	15.718944	16.358031	17.250213	18.078096	18.128886	23.422921
11	Lothian and Borders	11.121405	11.457176	11.562167	11.688719	11.810714	19.294493
12	Solway and Cheviot	9.294641	9.335609	9.405604	10.393097	10.039954	14.031597
13	North East England	6.486053	6.510343	5.171552	5.708998	3.891160	1.363769
14	North Lancashire and The Lakes	3.562511	3.271032	3.256158	3.439203	2.871971	3.898253
15	South Lancashire, Yorkshire and Humber	0.800363	0.555599	-0.924225	-0.765117	-1.465438	-2.022201
16	North Midlands and North Wales	0.109455	-0.400127	-1.683607	-0.667632	-1.437671	-1.914220
17	South Lincolnshire and North Norfolk	-0.417349	0.145169	-1.305013	-1.011906	-1.960617	-2.631960
18	Mid Wales and The Midlands	0.345324	0.412657	-0.013329	-0.566090	-1.929066	-3.491929
19	Anglesey and Snowdon	0.360272	-0.546926	-1.624235	-0.102009	-0.899765	-1.400423
20	Pembrokeshire	-2.305321	-4.144706	-5.482011	-5.797033	-6.970991	-7.900005
21	South Wales & Gloucester	-2.642943	-4.306933	-5.976739	-6.079623	-6.900971	-7.969074
22	Cotswold	-5.837012	-8.908485	-11.523888	-12.687549	-13.530693	-12.183991
23	Central London	-8.669303	-4.540565	-5.619071	-6.327946	-7.551449	-10.132277
24	Essex and Kent	1.157634	0.794005	-0.452469	-1.185318	-2.661189	-5.540643
25	Oxfordshire, Surrey and Sussex	-0.615006	-1.821760	-3.538546	-4.212765	-5.472632	-7.868895
26	Somerset and Wessex	-1.189407	-2.751329	-4.229852	-5.142769	-6.500965	-8.730754
27	West Devon and Cornwall	-2.359346	-4.002209	-6.350206	-7.546821	-9.181813	-9.856305

Figure 3 Wider tariffs for an Intermittent (45%) generator



Locational changes

Locational tariffs are generally expected to become more polarised over the next 5 years, mainly driven by the north- south flows in the best view scenarios. The best view has been aligned to a 5-year generation forecast central case produced by FES (future Energy Scenarios).

In 2027/28 the impact of a new HVDC link (Torness to Hawthorn Pit) can be seen, particularly in Scottish and North England zones, with zones 13-18 seeing decrease in tariffs for conventional carbon and conventional low carbon, getting close to £0/kW or switching negative. The opposite can be seen in zones 1 -12 for all Scottish generators, as the HVDC link cuts across the Cheviot boundary (B6 Scotland – England).

Zone 4 (Skye) and Zone 7 (Argyll) are sensitive to generation/demand changes, due to the relatively long radial circuits predominantly at 132kV (and thus having high "unit costs").

To view the changes in generation in each zone, please see Table A in the accompanying tables spreadsheet published on our website here and Table 34 on page 70.

It is worth noting that the ongoing review of the Expansion Constant and Factors calculation through CMP315/375 and the resulting decision could impact locational charges. Please refer to the expansion constant sensitivity on page 44 for an analysis of the impact of variation in the Expansion Constant. For further information on Modification CMP317/275 please refer to the workgroup notes [6].

[6] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp375-enduring

Adjustment tariff changes

The adjustment tariff has been implemented through CMP317/327, where the generation residual has been removed. However, to ensure compliance with the gen cap there is still a requirement for an adjustment tariff. The adjustment tariff is currently forecast to be negative in the next five years due to the wider tariffs causing the average generation charge to breach the cap.

In addition to CMP317/327, the ESO raised CMP368/369 in 2021, to fully align the CUSC methodology with Ofgem's interpretation of the Limiting Regulation. Due to the ongoing JR, Ofgem have not made a decision on CMP368/369 which is dependent on CMP317/327 outcome. In this report, our tariffs reflect CMP317/327 impacts, but do not include CMP368/369 impacts as we expect the CMP368/369 impacts are relatively small, around £10~20m maximum on generation adjustment revenue. We have already undertaken a preliminary assessment of the gen cap under CMP368/9, based on the original proposal, in the November 2021 report on 2022/23 Draft TNUoS tariffs.

The adjustment tariff is forecast to increase from -£0.96/kW in 2023/24 to -£5.33/kW in 2027/28 due to the change in the wider locational charges. These changes cause the adjustment tariff to go less negative as there is less adjustment require to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see

Table 26.

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.

For this five-year view, we have assumed that the onshore substation tariffs set in RIIO-2, will be inflated in line with CPIH. We have published the inflation indices in Table 21 on page 35.

Table 10 Local substation tariffs

2023/24 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.158491	0.079249	0.054662
<1320 MW	Redundancy	0.333959	0.169623	0.120443
>=1320 MW	No redundancy	-	0.232832	0.165770
>=1320 MW	Redundancy	-	0.350373	0.252003

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.

Onshore local circuit tariffs have been updated using the latest transport model, and for most existing users, the changes are minimal since the 2022/23 Final Tariffs (barring inflation). The 2023/24- 2027/28 onshore local circuit tariffs are listed in below in Table 11.

Table 11 Onshore local circuit tariffs

Connection Point	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	Connection Point	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)	Connection Point	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)
Aberdeen Bay	2.807792	2.863948	2.921227	2.979651	3.039244	Euchanhead					2.121325	Mossford	3.102389	3.164409	3.227664	3.292182	3.358003
Achruach	-2.749481	-2.804406	-2.860731	-2.917571	-2.976627	Ewe Hill	1.637992	1.670752	1.704167	1.738250	1.773015	Mossy Hill			50.089521	50.444978	50.802068
Aigas	0.720316	0.734722	0.749416	0.764405	0.779693	Fallago	-0.069240	-0.069312	-0.069417	-0.070674	-0.030773	Muaithebheal					61.637553
An Suidhe	-1.029043	-1.049556	-1.070779	-1.091985	-1.114539	Farr	3.839522	3.916312	3.994638	4.074531	4.156022	Nant	-1.352968	-1.380036	-1.903814	1.664498	1.697788
Arecleoch	2.559646	2.610839	2.663056	2.766186	1.726843	FASQUE					3.279628	Necton	-0.681033	0.812722	0.878911	0.891432	0.912496
Ayrshire Grid Service		0.152243	0.155288	0.158394	0.161562	FAW SIDE			5.154813	5.258438	5.330212	Quantans Hil					-0.179114
Beaw Field			55.123265	55.579397	56.039175	Fernoch	4.844490	4.941382	5.040236	5.141044	5.243867	Rhigos	0.113753	0.116091	0.119672	0.122037	0.124484
Beinn Tharsuinn			7.980097	8.139699	8.302493	Ffestiniogg	0.272449	0.277898	0.283456	0.289125	0.294908	Rocksavage	0.019451	-0.019841	-0.020239	-0.020644	-0.021058
Beinneun Wind Farm	1.451300	1.480314	1.509907	1.540091	1.570883	Fife Grid Service		0.132939	0.135597	-0.138309	-0.141075	RYHALL					-0.443132
Bhlaraidh Wind Farm	0.711091	0.725313	0.739819	0.754616	0.769708	Finlarig	0.352653	0.359706	0.366900	0.374239	0.381723	Sallachy			5.067021	5.168355	5.271719
Black Hill	1.672386	1.705834	1.739951	1.774750	1.810245	Foyers	0.315436	0.321745	0.328180	0.334744	0.341439	Saltend	0.018685	-0.002263	-0.002308	-0.002354	-0.002402
Black Law	1.924479	1.962969	2.002228	2.042273	2.083118	Galawhistle	1.763267	1.798532	1.834502	1.871193	1.908616	Sandy Knowe	3.472632	3.542085	3.462220	3.696073	3.769994
BlackCraig Wind Farm	6.400996	6.529016	6.773161	6.908624	7.046797	Gills Bay			2.821541	2.877972	2.935532	Sanquhar II		3.394944	3.899176	2.684778	2.738473
BlackLaw Extension	4.081108	4.162730	4.245985	4.330904	4.417522	Glen Kyllachy	0.503790	0.513866	0.524144	0.534626	0.545319	Scoop Hill			0.495528	0.505439	0.515548
BLARGHOUR			-0.020392	3.585589	3.657301	Glen Ullinish				8.054868	8.218993	SHEIRDRIM			-3.619107	-3.691103	-3.765522
Chirmorie					1.268978	Glendoe	2.025852	2.066369	2.107697	2.149851	2.192848	Shepherd Rig		0.566746	0.577070	0.228485	0.261383
Clash Gour			0.572689	0.584336	0.596478	Glenglass	5.106706	5.208841	5.431746	5.410701	5.518915	South Humber Bank	-0.200115	-0.204087	-0.208181	-0.212339	-0.216575
Clauchrie					1.986393	Glenshero		0.284418	0.070257	0.071662	0.073095	Spalding	0.290331	0.297446	0.303159	0.309990	0.316849
CLOICHE			2.707284	2.761429	2.816658	Gordonbush	1.338879	-0.016134	0.086771	0.141762	0.161465	STORNOWAY			53.634499	54.726528	55.820817
Clyde (North)	0.120782	0.123198	0.125662	0.128175	0.130739	Griffin Wind	10.445963	10.654807	10.867764	11.084521	11.305813	STRANOCH					2.341439
Clyde (South)	0.139679	0.142472	0.145322	0.148228	0.151193	Hadyard Hill	3.048434	3.109403	3.171591	3.235023	3.299723	Strathbrora	0.908573	-0.138839	-0.046370	0.002112	0.018747
Corriegarth	2.686882	2.740620	2.795432	2.851341	2.908368	Harestanes	2.574369	2.625857	2.678374	2.731941	2.786580	Strathy Wind	2.126069	1.885630	2.277520	2.355309	2.141572
Corriemoillie	1.793384	1.829224	1.865776	1.903056	1.941095	Hartlepool	0.097079	0.099933	0.102387	0.104819	0.034461	Stronelairg	1.171727	1.195691	0.999756	1.019751	1.040146
Coryton	0.050626	0.052070	0.053137	0.047730	0.055678	Hesta Head					10.203010	Wester Dod	0.374764	0.382260	0.389905	0.397703	0.405657
Costa Head					5.609987	High Marnham	-0.078832	-0.079760	-0.080969	-0.082335	-0.084065	Whitelee	0.116886	0.119224	0.121608	0.124040	0.126521
CREAG RIABHACH	3.694463	3.768352	3.843719	3.920594	3.999006	Holm Hill		-0.586409	1.400365	1.428227	1.485120	Whitelee Extension	0.324943	0.331442	0.338071	0.344832	0.351729
Cruachan	1.965559	2.004918	2.045160	2.086160	1.255678	Invergarry	0.403032	0.411093	0.419315	0.427701	-0.216662						
Culligran	1.908853	1.947030	1.985971	2.025690	2.066204	Kergord		47.086400	46.350464	46.631140	46.911953						
Cumberhead West		3.406716	3.474851	3.544348	3.615234	Kilgallioch	1.159120	1.182302	1.205948	1.230067	0.210869						
Deanie	3.135973	3.198692	3.262666	3.327920	3.394478	Kilmorack	0.217510	0.221860	0.226297	0.230823	0.235440						
Dersalloch	2.652956	2.706015	2.760135	2.815338	2.871645	Kype Muir	1.633588	1.666260	1.699585	1.733576	1.768248						
Dinorwig	2.583740	2.635415	2.688123	2.741885	2.796723	Lairg			0.391524	0.398175	0.406461						
Dorenell	2.259981	2.305181	2.351285	2.398310	2.446276	Langage	0.708704	-0.376425	-0.375687	-0.377224	0.766257						
Douglas North					0.817978	Limekilns		0.834471	0.851161	0.868184	0.885548						
Dumnaglass	0.936938	0.955677	0.974791	0.994286	1.014172	Lochay	0.403032	0.411093	0.419315	0.427701	0.436255						
Dunhill	1.542437	1.573286	1.604752	1.636847	1.669584	Luichart	0.619320	0.631679	0.644279	0.657129	0.670249						
Dunlaw Extension	1.634339	1.667990	1.682124	1.716204	1.737735	Marchwood	0.411708	0.419930	-0.261366	-0.267224	-0.271917						
Edinbane	7.539269	7.690195	7.843928	8.003881	8.166986	Middle Muir	2.530707	2.581321	2.632948	2.685607	2.739319						
Elchies			2.399414	2.447402	2.496350	Middleton	0.163877	0.169989	0.001077	0.002630	-0.001000						
Energy Isles					57.756931	Millennium South	0.519639	0.530053	0.540658	0.551797	0.563152						
Enoch Hill	1.614905	1.647203	1.680148	1.713750	1.748025	Millennium Wind	1.808555	1.844715	1.881595	1.919213	1.957588						

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 12 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
Coalburn 132kV	Cumberhead West 132kV	11.1km Cable	11.1km OHL	Cumberhead West
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	Galawhistle 132kV	10.5km Cable	10.5km OHL	Galawhistle
Knocknagael 275kV	Red John 275kV	9km Cable	9km OHL	Red John
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
Glenshero 132kV	Melgarve 132kV	5km Cable	5km OHL	Glenshero

Offshore local tariffs for generation

6. Offshore local generation tariffs

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

Table 13 shows the forecast of tariffs for 2023/24 and a comparison to the 2022/23 Final Tariffs. These tariffs are only subject to indexation in the remaining years of this forecast, so they have not been included in this table.

Offshore local generation tariffs associated with projects due to transfer in 2022/23 onwards will be confirmed once asset transfer has taken place.

Table 13 Offshore local tariffs 2023/24

Offshore Generator	2022/23 Final Tariff Component (£/kW)			2023/24 April Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	9.193620	48.569420	1.206045	9.809468	51.822915	1.286834	0.615848	3.253495	0.080789
Beatrice	7.738282	21.105031	-	8.148209	22.397333	-	0.409927	1.292302	-
Burbo Bank	11.581837	22.384141	-	12.348075	23.865045	-	0.766238	1.480904	-
Dudgeon	16.940266	26.579538	-	18.061011	28.338003	-	1.120745	1.758465	-
Galloper	17.340653	27.426026	-	18.487887	29.240495	-	1.147234	1.814469	-
Greater Gabbard	17.129624	39.639672	-	18.277077	42.294994	-	1.147453	2.655322	-
Gunfleet	20.007271	18.450293	3.448466	21.347488	19.686213	3.679466	1.340217	1.235920	0.231000
Gwynt y mor	21.749280	21.503123	-	23.188182	22.925740	-	1.438902	1.422617	-
Hornsea 1A	7.741153	27.389407	-	8.253296	29.201452	-	0.512143	1.812045	-
Hornsea 1B	7.741153	27.389407	-	8.253296	29.201452	-	0.512143	1.812045	-
Hornsea 1C	7.741153	27.389407	-	8.253296	29.201452	-	0.512143	1.812045	-
Humber Gateway	12.799572	29.366622	-	13.646374	31.309478	-	0.846802	1.942856	-
Lincs	17.768864	69.878865	-	18.944427	74.501954	-	1.175563	4.623089	-
London Array	12.058331	41.343394	-	12.856093	44.078615	-	0.797762	2.735221	-
Ormonde	28.266390	52.836011	0.421059	30.159856	56.375309	0.449264	1.893466	3.539298	0.028205
Race Bank	10.258559	28.492731	-	10.937251	30.377770	-	0.678692	1.885039	-
Rampion	8.380255	21.922390	-	8.934681	23.372745	-			
Robin Rigg	-0.620411	35.215839	11.282931	-0.661971	37.574824	12.038735	-0.041560	2.358985	0.755804
Robin Rigg West	-0.620411	35.215839	11.282931	-0.661971	37.574824	12.038735	-0.041560	2.358985	0.755804
Sheringham Shoal	26.445404	31.146260	0.677028	28.216888	33.232638	0.722380	1.771484	2.086378	0.045352
Thanet	20.194388	37.834233	0.910803	21.547139	40.368615	0.971815	1.352751	2.534382	0.061012
Walney 1	24.413618	48.809029	-	26.049000	52.078574	-	1.635382	3.269545	-
Walney 2	22.713291	46.223810	-	24.234774	49.320180	-	1.521483	3.096370	-
Walney 3	10.537649	21.348645	-	11.234805	22.761042	-	0.697156	1.412397	-
Walney 4	10.537649	21.348645	-	11.234805	22.761042	-	0.697156	1.412397	-
West of Duddon Sands	9.424073	46.977768	-	10.047556	50.085752	-	0.623483	3.107984	-
Westermost Rough	19.162273	32.611753	-	20.430023	34.769302	-	1.267750	2.157549	-

See Tables file for annual (2023/24 – 2027/28) breakdown of offshore local tariffs

Demand Tariffs

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

nationalgridESO

7. Demand tariffs summary

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

In this report, we have calculated and forecast demand tariffs for 2023/24 – 2027/28 which includes the implementation of CMP343: 'Transmission Demand Residual bandings and allocation' which will take effect from 1st April 2023.

Table 14 Summary of demand tariffs

Non-locational Banded Tariffs	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Average (£/site/annum)		92.053240	94.968322	93.167042	93.535237	92.053240
Unmetered (p/kWh)		1.1095838	1.1447214	1.1230092	1.1274473	1.1552230
Demand Residual (£m)	2,868	2,926	3,018	2,961	2,973	2,926
HH Tariffs (Locational)	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Average Tariff (£/kW)	55.062816	4.767689	4.826937	4.790433	4.845214	4.925075
Residual (£/kW)	56.861767					
EET	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Average Tariff (£/kW)	2.075319	2.115591	2.236043	2.136232	2.308390	2.278555
Phased residual (£/kW)	-	-	-	-	-	-
AGIC (£/kW)	2.344515	2.464586	2.513878	2.564156	2.615439	2.667748
Embedded Export Volume (GW)	7.533414	7.384554	7.066286	7.149919	6.858276	7.427089
Total Credit (£m)	15.6	15.6	15.8	15.3	15.8	16.9
NHH Tariffs (locational)	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Average (p/kWh)	6.809814	0.227167	0.243272	0.243518	0.247097	0.245298

In Table 14 the impact of the change in methodology for demand charges can be seen. The switch to the demand residual charging bands in 2023/24 onwards, removes the demand residual element (total demand revenue less locational demand revenue) from HH and NHH tariffs (now known as the Locational HH and NHH tariffs) and the average HH and NHH tariff becomes solely based on locational demand tariffs and the forecast revenue to be collected through the demand locational. The impact of the demand residual banded charges can be seen at the top of the table and the revenue to be recovered each year through the new charge is shown in the 'Demand residual' line. The average charge (£ per site per annum) shows the trend year-on-year, refer to Table 15 to see the charges across each band. As charges range from as low as £15.09 (LV_NoMic1 in 2023/24) to £3,225m (T-demand band 4 in 2027/28) per site per annum.

8. Demand Residual Banding Tariffs

From 2023/24 onwards, we have used the agreed distribution connected bandings and unmetered demand for the demand residual tariffs. As per the CMP343 decision we have based the banded charges for transmission connect demand on 4 bands whereby the threshold for each band is comparable to the percentiles used in the distribution level bands (LV No MIC to EHV). It is worth highlighting that as part of the decision, there is a possibility of the further mods to be raised. One of those potential Mods is to review the number of transmission connected bands and the percentile thresholds used across those bands. A breakdown of the banding thresholds, consumptions, consumption proportions and site count for the demand residual banded charges can be seen in Table TB.

Below in Table 15 are the forecast demand residual banded tariffs across each of the banding criteria. These tariffs will apply to HH and NHH demand as well the locational HH and NHH tariffs (where applicable).

Table 15 Non-Locational demand residual banded charges

Band	Tariff	2023/24	2024/25	2025/26	2026/27	2027/28
Domestic	£/Site per Annum	36.81	37.97	37.25	37.40	38.32
LV_NoMIC_1		15.09	15.57	15.27	15.33	15.71
LV_NoMIC_2		85.35	88.06	86.39	86.73	88.86
LV_NoMIC_3		210.53	217.20	213.08	213.92	219.19
LV_NoMIC_4		665.22	686.29	673.27	675.93	692.58
LV1		1,061.49	1,095.11	1,074.34	1,078.58	1,105.15
LV2		1,993.89	2,057.03	2,018.02	2,025.99	2,075.90
LV3		3,239.31	3,341.89	3,278.50	3,291.46	3,372.55
LV4		7,358.82	7,591.86	7,447.86	7,477.29	7,661.50
HV1		4,909.20	5,064.66	4,968.60	4,988.24	5,111.13
HV2		17,778.41	18,341.40	17,993.52	18,064.63	18,509.66
HV3		34,737.54	35,837.58	35,157.85	35,296.79	36,166.36
HV4		89,495.74	92,329.83	90,578.60	90,936.56	93,176.86
EHV1		55,810.06	57,577.42	56,485.34	56,708.57	58,105.63
EHV2		216,161.23	223,006.48	218,776.68	219,641.28	225,052.34
EHV3		457,136.17	471,612.45	462,667.30	464,495.76	475,939.02
EHV4		1,182,280.46	1,219,720.15	1,196,585.52	1,201,314.40	1,230,909.83
T-Demand1		135,438.52	139,727.50	137,077.26	137,618.99	141,009.35
T-Demand2		484,704.19	500,053.48	490,568.89	492,507.61	504,640.96
T-Demand3		1,057,794.39	1,091,291.93	1,070,593.22	1,074,824.18	1,101,303.42
T-Demand4		3,097,790.30	3,195,889.10	3,135,272.15	3,147,662.68	3,225,208.12
Unmetered demand						
Unmetered	p/kWh	1.11	1.14	1.12	1.13	1.16
Demand Residual (£m)		**2,925.56**	**3,018.21**	**2,960.96**	**2,972.66**	**3,045.90**

There above tariffs are calculated based on the current approved published distribution banding thresholds (LV No MIC through to EHV) for RIIO-2 and as per the decision of CMP343, there are 4 transmission connected bands. The thresholds for the T-connected bands are based on average transmission connected consumption data from 2019/20 to 2020/21 and the sites connected over that time. The transmission thresholds will be refined as we progress through to 2023/24 draft tariffs and may also be impacted by any future mods raised in relation to the transmission connected banding. The consumption, consumption proportions and site counts used in the calculation of the above tariffs and are based on the out-turn data from 2020/21 provided by the DNO/IDNO's last October the equivalent timescales have been used for the calculation of the transmission connected banded tariffs. We will be provided with the out-turn data for 2021/22 by the DNO/IDNO's later this year. The transmission connected out-turn demand data for 2021/22 which the ESO produces will also be made available at the same time. These updated values will be included in the Draft and Final tariffs for 2023/24. We currently have no mechanism for forecasting future consumption and site counts across demand residual bands, therefore the only impact on the annual variance in tariffs is the change in the revenue to be recovered through demand residual, which can be seen at the bottom of the above table.

9. Half-Hourly demand tariffs

The implementation of the demand residual charging bands via CMP343 will have a significant impact on the HH tariffs and the way in which HH customers are charged. As stated above, from 2023/24 the introduction of this new methodology will remove the current demand residual tariff from the HH tariff. The HH tariff (£/kW) will continue to be based on average demand taken over the triad periods but will only be reflective of the zonal locational demand tariffs. As such, the majority of the HH revenue would be collected through the new demand residual banded tariffs on a fixed £ per site per annum basis.

In 2023/24 the average locational HH tariffs is forecast at £4.76/kW, which will then increase to £4.93/kW in 2027/28.

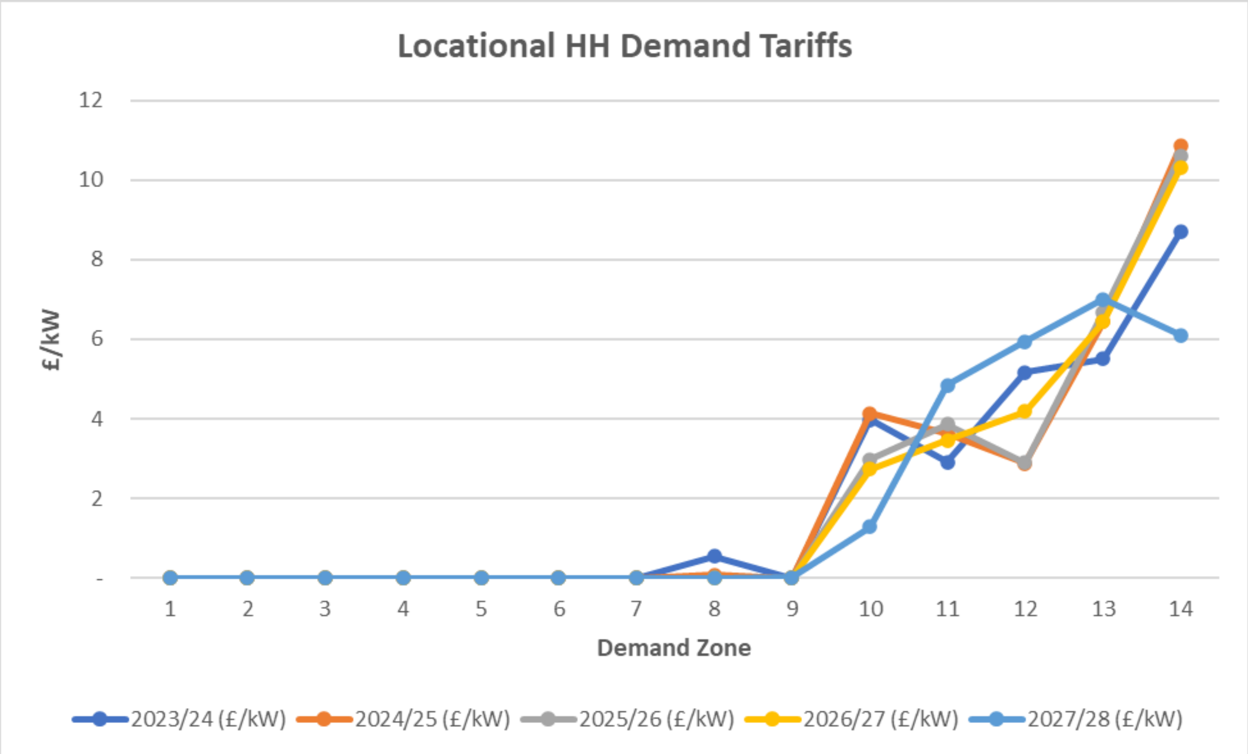
As per CMP343 decision tariffs will be floored at £0/kW from 2023/24 With locational tariffs being floored at £0/kW, demand zones 1 to 7 and zone 9 are set to £0/kW from 2023/24. By 2027/28 zones 1 to 8 will be floored at £0/kW with zone 9 increase back to a positive value. Small fluctuations can be seen in the remaining zones that have not been floored. These fluctuations are within the normal bounds, but due to the removal of the residual element these variations will be more prominent in comparison.

The table and figure below show the locational HH demand tariffs by demand zone for 2023/24 to 2027/28.

Table 16 Half-Hourly demand tariffs for 2023/24 to 2027/28

Zone	Zone Name	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	-	-	-	-	-
8	Midlands	0.547267	0.068698	-	-	-
9	Eastern	-	-	-	-	0.017082
10	South Wales	3.972019	4.142908	2.973003	2.729905	1.279380
11	South East	2.905305	3.643670	3.867113	3.456960	4.837480
12	London	5.168789	2.878672	2.896779	4.182788	5.932285
13	Southern	5.504939	6.443991	6.688704	6.442192	7.007095
14	South Western	8.694899	10.854774	10.618903	10.305393	6.103114

Figure 4 Changes to gross Half-Hourly demand tariffs



The breakdown of the HH locational tariff into the peak and year-round components can be found in Appendix C.

10. Embedded Export Tariffs (EET)

The Embedded Export Tariff is designed to make credit payment to embedded generators (who are not eligible to be charged generation TNUoS tariffs with TEC lower than 100MW) for their metered exports over the triad periods.

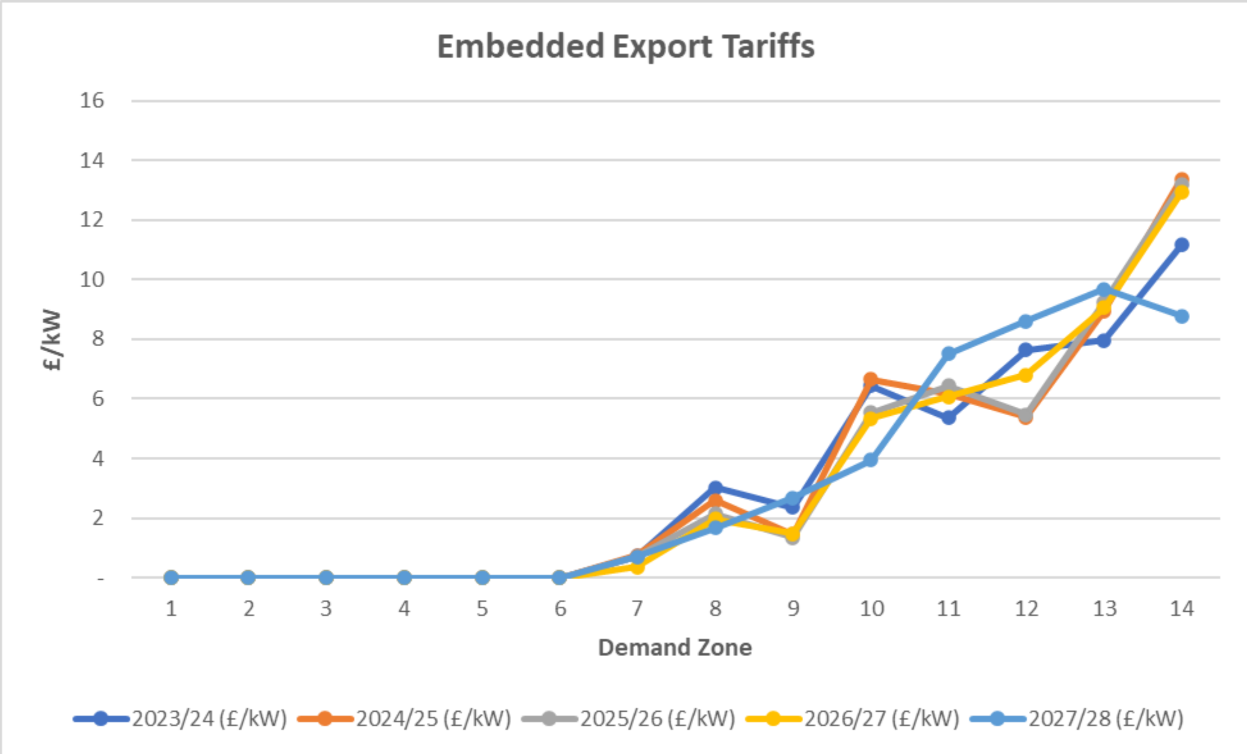
These embedded generators are paid either directly by the ESO or through their supplier when the initial demand reconciliation has been completed in accordance with CUSC (see 14.17.19 onwards). The payment to the EET is recovered through demand revenue, which will affect the price of HH and NHH demand tariffs. There is no direct impact to the EET, through the implementation of the TDR demand residual charging banding methodology.

Table 17 shows the forecasted Embedded Export Tariffs by zone in the years 2022/23 to 2026/27.

Table 17 Embedded Export Tariffs for 2023/24 to 2027/28

Zone	Zone Name	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)	2027/28 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	0.729141	0.736167	0.704306	0.352546	0.706396
8	Midlands	3.011853	2.582576	2.145264	1.972748	1.659831
9	Eastern	2.354156	1.451616	1.354438	1.483212	2.684830
10	South Wales	6.436605	6.656786	5.537159	5.345344	3.947128
11	South East	5.369891	6.157548	6.431269	6.072399	7.505228
12	London	7.633375	5.392550	5.460935	6.798227	8.600033
13	Southern	7.969525	8.957869	9.252860	9.057631	9.674843
14	South Western	11.159485	13.368652	13.183059	12.920832	8.770862
	These tariffs include:					
	Phased residual (£/kW)	-	-	-	-	-
	AGIC (£/kW)	2.464586	2.513878	2.564156	2.615439	2.667748

Figure 5 Embedded export tariff changes



In this forecast of the EET, one of the key changes is the continuing inflation of the AGIC. In 2023/24 the AGIC is forecast at £2.46/kW (an increase of £0.12/kW from 2022/23 final tariffs), increasing to £2.67/kW by 2027/28. The fluctuation in the demand locational tariffs over the next 5 years also play their part, as well the changes in the forecast of embedded export. 2023/24 The average EET is forecast at £2.11/kW, which is a slight increase in comparison to comparable 2022/23 tariffs. Over the 5 years the average EET will fluctuate (see Table 14) and in 2026/27 will reach a high of £2.31/kW, then dropping to £2.27/kW in 2027/28. The greater increase in average tariff in 2026/27 is due to the lower forecast in embedded export in comparison to other years.

The breakdown of the EET locational tariff into the peak and year-round components (the same values are used for HH tariff and EET, however the tariffs are floored at £0/kW) can be found in Appendix C.

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 tariffs.

11. Locational Non-Half-Hourly demand tariffs

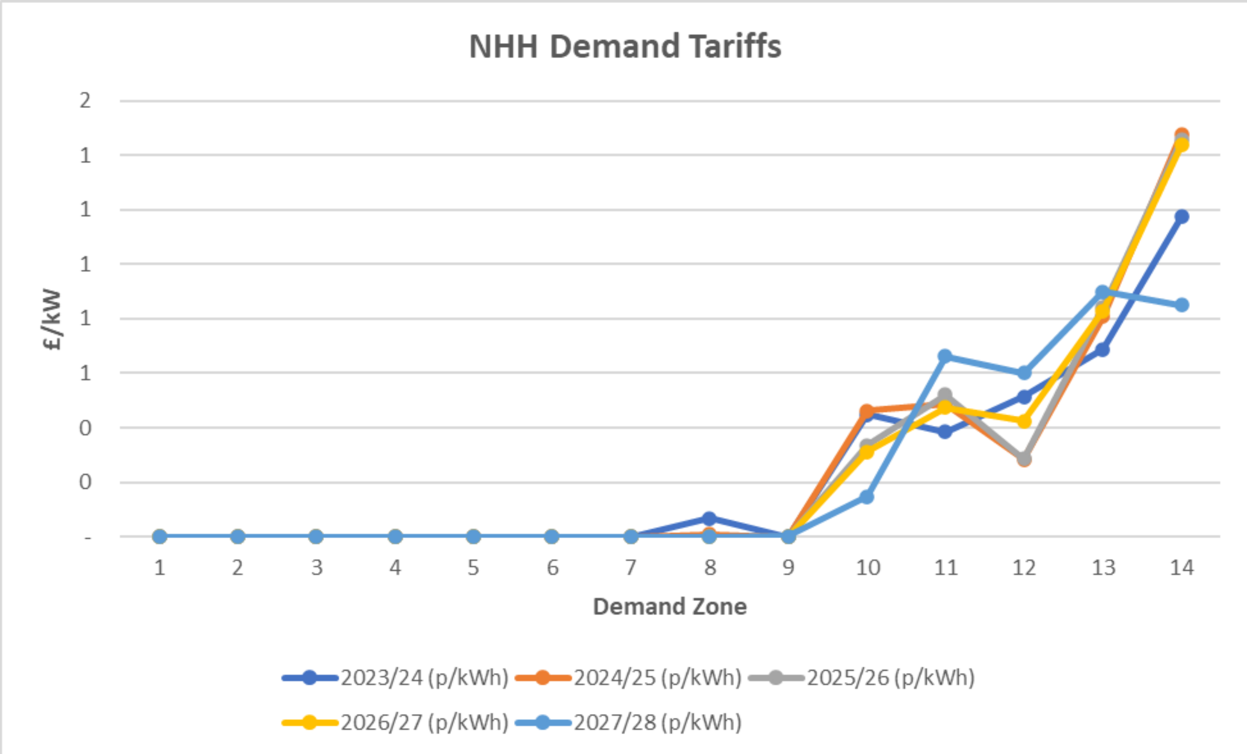
As with HH demand (now referred to as locational HH demand tariffs), the new TDR methodology significantly impacts NHH tariffs (now referred to as locational NHH demand tariffs), introducing a new set of banded tariffs for the demand residual element of demand revenue. From April 2023 (2023/24), NHH demand will continue to be subject to a p/kWh charge based on their consumption between 4pm-7pm every day of the year as they are currently. The amount paid will be significantly reduce due to the removal of the demand residual from the tariff calculation. As with locational HH demand tariffs, NHH tariffs will be floored at 0p/kWh which can be seen in Table 18. The additional £ per site per annum charge through the banded residual charges will also apply to NHH demand where applicable. For the demand residual tariffs for 2023/24 to 2026/27, please see Table 15.

Table 18 below shows the locational NHH demand tariffs for the next five years where the impact of the new banded demand residual charges can clearly be seen.

Table 18 Non-Half-Hourly demand tariffs from 2023/24 to 2027/27

Zone	Zone Name	2023/24 (p/kWh)	2024/25 (p/kWh)	2025/26 (p/kWh)	2026/27 (p/kWh)	2027/28 (p/kWh)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	-	-	-	-	-
8	Midlands	0.067926	0.008554	-	-	-
9	Eastern	-	-	-	-	0.002313
10	South Wales	0.447363	0.463199	0.334588	0.311837	0.147658
11	South East	0.385372	0.487435	0.520445	0.474347	0.662957
12	London	0.514028	0.283465	0.286360	0.425331	0.600466
13	Southern	0.686977	0.807441	0.842906	0.829798	0.899784
14	South Western	1.174085	1.477918	1.455855	1.437113	0.849648

Figure 6 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff forecast for 2023/24 is 0.23p/kWh, a 6.58p/kWh decrease compared to 2022/23 final tariffs, due to the change in demand charging methodology and the removal of the demand residual from the NHH p/kWh tariff. The locational NHH tariff is forecast to increase year-on-year through to 2026/27 which is where it will peak (0.247p/kWh) then drop slightly in 2027/28 to 0.245p/kWh.

The changes in locational NHH tariffs will largely be the same as the locational HH tariff and EET. As the main component of these tariffs going forward, will in most part be the impact of the locational Peak and Year-Round elements of demand. The year-on-year changes in charging base for NHH as a whole and the zonal fluctuations (4-7pm consumption) will also cause changes in the NHH tariffs, as will the proportion of NHH charging base versus the HH charging base. For example, an increase in forecast HH peak demand in a zone versus a decrease in NHH 4-7pm consumption in any given year, will increase the proportion of revenue to be recovered through locational HH demand tariff for that zone and reduce the location NHH tariff. This is also true for when the scenario is reversed.

Overview of data inputs

This section explains the changes to the input data which are fed into this five-year view.

12. Inputs affecting the locational element of tariffs

The locational element of generation and demand tariffs is based upon:

Contracted position of generation;

Nodal demand;

Local and MITS circuits;

Inflation;

Locational security factor

Expansion constant

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2023/24 period onwards, which can be found on the TEC register.[7] The contracted TEC volumes are based on the February 2022 TEC register.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the initial and August forecasts, we forecast our best view of modelled TEC. However, for our November Draft tariffs and January Final tariffs we will use the contracted TEC position as published in TEC register as of 31st October 2022, 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 2023/24 and liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2023.

Table 19 Contracted TEC

Generation (GW)	2023/24	2024/25	2025/26	2026/27	2027/28
Contracted TEC	90.96	109.57	136.65	158.98	176.93
Modelled Best View TEC	85.11	90.10	100.84	109.93	118.68
Chargeable TEC	74.89	77.97	84.86	93.91	102.67

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 2023/24 onwards as stated in the interconnector register as of February 2022.

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

Table 20 Interconnectors

Interconnector	Node	Zone	Generation MW 2023/24	2024/25	2025/26	2026/27	2027/28
Aminth	NORM40	18	0.00	0.00	0.00	0.00	0.00
Aquind Interconnector	LOVE40	25	0	0	2,000	2,000	2,000
Auchencrosh (interconnector CCT)	AUCH20	10	500	500	500	500	500
Britned	GRAI40	24	1,200	1,200	1,200	1,200	1,200
Continental Link	BLYT4A	13	0	0	0	0	1,800
Cronos	KEMS40	24	0	0	1,400	1,400	1,400
East West Interconnector	CONQ40	16	505	505	505	505	505
ElecLink	SELL40	24	1,000	1,000	1,000	1,000	1,000
EuroLink	LEIS4A	18	0	1,600	1,600	1,600	1,600
FAB Link Interconnector	EXET40	26	0	0	1,400	1,400	1,400
Greenlink	PEMB40	20	0	504	504	504	504
Gridlink Interconnector	KINO40	24	0	1,500	1,500	1,500	1,500
IFA Interconnector	SELL40	24	2,000	2,000	2,000	2,000	2,000
IFA2 Interconnector	CHIL40	26	1,100	1,100	1,100	1,100	1,100
Kulizumboo Interconnector	CANT40	24	0	0	0	0	700
MARES	BODE40	16	0	0	750	750	750
Nautilus	LEIS40	18	0	0	0	0	1,500
Nemo Link	RICH40	24	1,020	1,020	1,020	1,020	1,020
NeuConnect Interconnector	GRAI40	24	1,400	1,400	1,400	1,400	1,400
NorthConnect	PEHE20	2	0	0	0	1,400	1,400
NS Link	BLYT4A	13	1,400	1,400	1,400	1,400	1,400
Southernlink	GRAI40	24	0	0	0	0	1,500
Tarchon	CORI10	1	0	0	0	1,400	1,400
The Superconnection	CREB40	15	0	0	0	0	1,000
Viking Link Denmark Interconnector	BICF4A	17	1,500	1,500	1,500	1,500	1,500

14. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. The 2023/24 Expansion Constant is set at £16.254708/MWkm. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. 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). For the purposes of this forecast, the EC will continue to increase in-line with inflation, as per the CMP353 methodology. The impacts of CMP315/375, which may impact 2023/24 tariffs, will be included in our forecast publications once the modification has reached a sufficient stage of development.

Table 21 Expansion Constant

£/MWkm		2023/24	2024/25	2025/26	2026/27	2027/28
Expansion Constant		16.254708	16.579802	16.911398	17.249626	17.594619
	2018/19	2023/24	2024/25	2025/26	2026/27	2027/28
Base Revenue Inflation indices	1.000000	1.118877	1.146196	1.169722	1.193131	1.218965

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 guidance 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 five-year view, onshore substation tariffs are based on the values set for RIIO-2 and are 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.

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, the Strategic Innovation Fund. The total amount recovered is adjusted for interconnector revenue recovery or redistribution.

For onshore TOs, the allowed revenues have been based on TOs forecast reflecting Ofgem's final determination on their RIIO-2 parameters including project spending profiles, rate of return and inflation index.

For more details on TNUoS revenue breakdown, please refer to Appendix F.

Table 22 Allowed revenues

£m Nominal	2023/24	2024/25	2025/26	2026/27	2027/28
TO Income from TNUoS					
National Grid Electricity Transmission	1,991.6	1,995.2	1,995.9	2,035.8	2,076.5
Scottish Power Transmission	421.2	430.6	420.5	428.9	437.5
SHE Transmission	712.4	801.9	759.7	740.0	758.5
Total TO Income from TNUoS	**3,125.2**	**3,227.7**	**3,176.2**	**3,204.8**	**3,272.6**
Other Income from TNUoS					
Other Pass-through from TNUoS	87.0	75.4	75.2	78.2	81.6
Offshore (plus interconnector contribution / allowance)	735.2	800.3	887.6	959.0	1,051.1
Total Other Income from TNUoS	**822.2**	**875.7**	**962.8**	**1,037.3**	**1,132.6**
Total to Collect from TNUoS	**3,947.3**	**4,103.5**	**4,139.0**	**4,242.0**	**4,405.2**

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

The revenue to be collected from generators and demand users for 2023/24 will be updated throughout quarterly tariff forecasts and will be finalised in the Final Tariffs.

The G/D split forecast is shown in Table 23.

Table 23 Generation and demand revenue proportions

Code	Revenue	2023/24	2024/25	2025/26	2026/27	2027/28
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
y	Error Margin	0.14	0.14	0.14	0.14	0.14
ER	Exchange Rate (€/£)	1.17	1.17	1.17	1.17	1.17
MAR	Total Revenue (£m)	3,947.00	4,103.11	4,138.61	4,241.69	4,404.85
GO	Generation Output (TWh)	194.88	199.88	206.92	212.30	212.30
G	% of revenue from generation	0.24	0.25	0.27	0.28	0.29
D	% of revenue from demand	0.76	0.75	0.73	0.72	0.71
G.R	Revenue recovered from generation (£m)	944.18	1,007.82	1,101.09	1,190.49	1,278.55
D.R	Revenue recovered from demand (£m)	3,002.81	3,095.30	3,037.51	3,051.20	3,126.30
Breakdown of generation revenue						
	Revenue from the Peak element	129.20	121.15	94.22	95.92	65.23
	Revenue from the Year Round Shared element	124.24	140.86	194.49	216.08	299.81
	Revenue from the Year Round Not Shared element	176.19	290.22	320.66	446.74	571.89
	Revenue from Onshore Local Circuit tariffs	17.05	39.54	57.02	72.46	86.55
	Revenue from Onshore Local Substation tariffs	10.66	10.87	11.63	13.14	15.16
	Revenue from Offshore Local tariffs	558.62	590.36	652.47	715.03	786.98
	Revenue from the adjustment element	-71.77	-185.18	-229.40	-368.88	-547.08
G.MAR	Total Revenue recovered from generation (£m)	944.18	1,007.82	1,101.09	1,190.49	1,278.55

The “gen cap”

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges in Great Britain to €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 is referred to as the “gen cap”. In this report, the term “gen cap” is used to refer to the “upper limit of the Limiting Regulation” in the CUSC.

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 were approved in December 2020 and were implemented since the 2021/22 tariffs. When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod (CMP368/369), to update charges for the physical assets required for connection, generation output and Generator charges associated with TNUoS-chargeable embedded generators, for the purpose of maintaining compliance with the Limiting Regulation (the [0 ~ €2.50]/MWh range). The latest development on the CMP317/327 legal challenge, means CMP368/369 decision is dependent on the JR outcome. In this five-year report, our forecast does not include CMP368/369 impacts but does include CMP317/327 as part of the current CUSC methodology. It should be noted that there is a risk that the tariffs may need to be calculated under a revised methodology, as a result of the JR outcome and/or any relevant Ofgem decisions.

Exchange Rate

Following CMP317/327, 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 will be locked down by 31st October ahead of the January final tariff setting. In this report, we have used the latest available OBR forecast at the time of tariff calculation (the October 2021 EFO), and the exchange rate is €1.17/£ across years 2023/24 to 2027/28. The March 2022 EFO[8] will be included in our August update on 2023/24 tariffs.

[8] https://obr.uk/economic-and-fiscal-outlooks/

Generation Output

The forecast output of generation are shown in Table 23. These figures are the average of the four scenarios plus the central case in the 2021 Future Energy Scenarios publication. For year 2023/24 tariff forecast, the generation output figure will be updated following the publication of FES 2022.

Error Margin

The error margin has remained unchanged at 14.2%, and will be updated in the August publication following outturn of 2021/22 data. The error margin is derived from historical data in the past five whole years (thus for year 2023/24, we will use data from years 2017/18 – 2021/22, once it is available).

Table 24 Generation revenue error margin calculation

Calculation for	2023/24		
	Revenue inputs		Generation output variance
Data from year:	Revenue variance	Adjusted variance	
2016/17	-5.1%	4.4%	-7.9%
2017/18	-5.2%	4.3%	-1.5%
2018/19	-9.2%	0.3%	-7.5%
2019/20	-14.6%	-5.2%	-4.1%
2020/21	-13.2%	-3.7%	7.5%
Systemic error:	-9.5%		
Adjusted error:		5.2%	7.9%
Error margin =			14.2%
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			

20. Charging bases for 2023/24 to 2027/28

Generation

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

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

The generation charging base for 2023/24 is forecast to be 74.89GW, increasing to 102.67GW in 2027/28 and is based on our internal view of what generation we expect to connect next five years. The best view has been aligned to a 5-year generation forecast central case produced by FES

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated for 2023/24 through to 2027/28.

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 2018 - March 2022)

Weather patterns

Future demand shifts

Expected levels of renewable generation

We assume that with recent historical trends and forward-looking assumptions (as well as the impacts that COVID has had on demand as a whole over recent years) volumes will stay relatively consistent over the next few years, with a slight decrease for both NHH demand and HH Triad demand through to 2025/26. This is due to the culmination of growth in distributed generation and “behind the meter” microgeneration offset by the increase in electric vehicles and heat pumps. However, it is anticipated that demand will begin to gradually increase again from 2026/27. As has been the case for previous tariff forecasts (since the impact of COVID-19 has been seen on demand charging bases), for this 5YV we have not included any additional adjustments to our demand charging base forecasting process in relation to COVID-19.

It is to be highlighted that with the removal of the demand residual from the locational HH and NHH tariffs the impact that changes in the demand charging bases have on charges, has been considerably reduced. Changes in the demand charging base forecasts will now only impact a small proportion of the overall revenue to be recovered through demand.

Please refer to table TAA in the published tables spreadsheet for a detailed breakdown of the changes to the demand changing bases.

Table 25 Charging bases

Charging Bases	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Generation (GW)	72.44	74.89	77.97	84.86	93.91	102.67
NHH Demand (4pm-7pm TWh)	24.96	24.54	23.55	23.30	23.23	23.41
Gross charging						
Total Average Gross Triad (GW)	50.44	49.72	48.34	48.15	48.94	49.35
HH Demand Average Gross Triad (GW)	19.41	19.48	19.24	19.17	19.48	19.76
Embedded Generation Export (GW)	7.53	7.38	7.07	7.15	6.86	7.43

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 2022/23 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 National Grid ESO website.[9]

22. Adjustment tariff 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 location tariffs) divided by the total chargeable TEC

[9] https://www.nationalgrideso.com/document/225826/download

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

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 can not be positive and is capped at 0.

On 21 November 2019, Ofgem published their final decision on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision. These changes took effect from April 2021 for the Transmission Generation Residual (TGR).

Subsequently CMP317/327 was raised and implemented from April 2021, to implement the TCR decision. Under CMP317/327, generation residual has been removed, but to ensure compliance with the gen cap within the range of €0-2.50/MWh, an adjustment mechanism has been introduced. Under CMP317/327, all local onshore and local offshore tariffs are not included in the gen cap, i.e. not included in the definition of Z_G. Please also note that some outstanding issues in calculating the gen cap are being addressed through CMP368/369, which is currently with Ofgem for a decision, and is also pending the outcome of the Judicial Review on Ofgem's CMP317/327 decision.

The **Demand Residual** = Total demand revenue less revenue recovered from locational demand tariffs, plus revenue paid to embedded exports

Through the approval and decision of CMP343 the demand residual tariff will no longer exist and will not be included in locational tariffs. The revenue to be recovered through the demand residual will now be recovered by a new set of £/site/annum (p/site/day) charges on final demand users (both HH and NHH), based on site specific banded charges starting April 2023.

Final demand in principle is consumption used for purposes other than to operate a generating station, or to store and export, and is defined in the CUSC through the approved CMP334. Each final demand site will be allocated to a “band” that is based on its capacity, annual energy consumption or other criteria, and all sites within the same band pay the same demand residual tariffs (£/site) each year.

Demand customers will continue paying 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. As per CMP343, HH and NHH demand locational tariffs are floored at zero from 2023/24, there will be no negative tariffs.

Table 26 Residual & Adjustment Tariff calculation

	Component	2023/24	2024/25	2025/26	2026/27	2027/28
G	Proportion of revenue recovered from generation (%)	23.92%	24.56%	26.61%	28.07%	29.03%
D	Proportion of revenue recovered from demand (%)	76.08%	75.44%	73.39%	71.93%	70.97%
R	Total TNUoS revenue (£m)	3,947.00	4,103.11	4,138.61	4,241.69	4,404.85
Generation revenue breakdown (without adjustment)						
RG	Generator adjustment tariff (£/kW)	-0.96	-2.37	-2.70	-3.93	-5.33
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	429.6	552.2	609.4	758.7	936.9
O	Revenue recovered from offshore local tariffs (£m)	558.6	590.4	652.5	715.0	787.0
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.7	10.9	11.6	13.1	15.2
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.1	39.5	57.0	72.5	86.5
BG	Generator charging base (GW)	74.9	78.0	84.9	93.9	102.7
Gross demand residual						
R_D	Demand residual tariff (£/kW)	63.2	67.2	66.2	65.7	67.5
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	92.9	92.9	91.8	94.4	97.3
EE	Amount to be paid to Embedded Export Tariffs (£m)	15.6	15.8	15.3	15.8	16.9
B_D	Demand Gross charging base (GW)	49.7	48.3	48.2	48.9	49.4

Sensitivity Analysis

nationalgridESO

Purpose

We are conscious that there are uncertainties with the charging methodologies over the next 5 years. To help the industry to understand the potential implications of the ongoing changes, we have undertaken further modelling around potential variables and have included some indicative tariffs / charges.

We asked the industry for suggestions of what sensitivities it would be helpful to see in our five-year view, we welcome the feedback received and as a result the sensitivity analysis that we have undertaken for 2023/24-2027/28 tariffs are:

1. A scenario which tests the impact of variation in the Expansion Constant for 2023/24
2. A scenario which tests the impact of additional revenue on TDR
3. A scenario which tests the impact of additional HVDC Bootstraps (the East Coast HVDC) for 2027/28
4. A scenario which tests the impact of links to Scottish Isles becoming part of the wider network for 2027/28

In addition to those listed above, we also considered completing a sensitivity analysis of the following scenarios, however we have not included them for the reasons given:

5. A scenario which tests the impact of CMP368/369: 'Updating Charges for the Physical Assets Required for Connection'[10] – we received feedback during March TCMF that it would not be right to pre-empt the outcomes of CUSC modifications where more than one solution has been raised. Since there are 20 options proposed under CMP368/369, we felt it is best not to undertake sensitivity analysis under a specific option. Under the original proposal, we expect the impacts of CMP368/369 would be in the region of £10~20m maximum on generation adjustment revenue.
6. A scenario which tests the impact of CMP316: 'TNUoS Arrangements for Co-located Generation Sites' – this is a live CUSC modification which is being developed by a workgroup. Following the feedback received during March TCMF, we have decided not to include this modification in the sensitivity analysis.
7. A scenario to test the impact of CMP343: 'Transmission Demand Residual bandings and allocation' – following the approval of CMP343 this scenario is no longer required. There is the possibility that follow up modifications may be raised to consider transmission connected banding/thresholds; if so, they will be incorporated into our forecast publications if and when they reach a stage of sufficient development.

Caveats

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

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

[10] CMP368: 'Updating Charges for the Physical Assets Required for Connection, Generation Output and Generator charges for the purpose of maintaining compliance with the Limiting Regulation' & CMP369: 'Consequential changes to Section 14 of the CUSC as a result of the updated definitions introduced by CMP368'

23. Impact of variation in the Expansion Constant

The EC and corresponding expansion factors (EFs) are required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. Following the implementation of CMP353, the current RIIO-2 EC value has been set to maintain inflation from the value set in the RIIO-T1 price control period and a review of the EC methodology and the expansion factors is ongoing with the industry (CMP315/375).

In this sensitivity we have assessed the indicative tariffs under scenarios where the expansion constant is 20% higher or lower than the value used in the base case. This sensitivity does not pre-suppose the result of the ongoing modification process for CMP315/375 and is intended only to demonstrate the impact that variance in EC and the corresponding EFs may have on tariffs.

The impact of an increase or decrease in expansion constant will have the same proportional effect regardless of the year, consequently this sensitivity analysis has only been shown for the year 2023/24.

The tables and charts below show the impact of an increase and decrease of 20% to the EC on indicative tariffs against the 5YV base case. For each tariff type, it can be seen that an increase/decrease to the EC has the effect of stretching/compressing the tariff. So, positive tariffs will increase or decrease in line with an increase or decrease to the EC. For negative tariffs, an increase to the EC will cause it to go more negative.

Table S1 Impact of variation in the Expansion Constant on Generation Wider Tariffs in 2023/24

2023/24 Generation Tariffs (£/kW)		Baseline			2023/24 Sensitivity (Baseline EC -20%)			2023/24 Sensitivity (Baseline EC +20%)		
Zone	Zone Name	Baseline Conventional Carbon (40%)	Baseline Conventional Low Carbon (75%)	Baseline Intermittent 45%	EC - 20%: Conventional Carbon (40%)	EC - 20%: Conventional Low Carbon (75%)	EC - 20%:Intermittent 45%	EC + 20%: Conventional Carbon (40%)	EC + 20%: Conventional Low Carbon (75%)	EC + 20%: Intermittent 45%
1	North Scotland	19.178437	37.278071	26.567730	17.097967	32.759136	23.817788	21.258908	41.797008	29.317673
2	East Aberdeenshire	14.347365	28.956757	22.080277	12.519930	24.764872	19.425498	16.174801	33.148644	24.735057
3	Western Highlands	17.466235	34.498436	25.027868	15.776603	30.634944	22.659641	19.155869	38.361930	27.396096
4	Skye and Lochalsh	13.329749	31.344181	26.664920	12.464017	28.103048	23.960791	14.195482	34.585315	29.369049
5	Eastern Grampian and Tayside	15.473074	28.964807	19.802488	13.718552	25.232408	17.723514	17.227596	32.697204	21.881461
6	Central Grampian	15.418387	29.407804	20.566808	13.889127	26.059256	18.731388	16.947648	32.756351	22.402227
7	Argyll	15.073911	31.753563	25.326563	14.194691	29.405211	24.028321	15.953132	34.101915	26.624805
8	The Trossachs	13.010850	24.865961	17.285661	11.906786	22.301492	16.001963	14.114913	27.430429	18.569359
9	Stirlingshire and Fife	11.342144	22.522515	16.267043	10.373439	19.998461	14.840014	12.310851	25.046572	17.694074
10	South West Scotlands	9.957493	21.198496	16.358031	9.296058	19.004292	14.964888	10.618929	23.392700	17.751174
11	Lothian and Borders	10.493168	18.793658	11.457176	9.571117	16.696720	10.660503	11.415219	20.890595	12.253849
12	Solway and Cheviot	6.730417	13.496480	9.335609	6.461308	12.268576	8.843189	6.999528	14.724386	9.828029
13	North East England	7.831093	12.800562	6.510343	7.221389	11.437790	6.341444	8.440798	14.163335	6.679243
14	North Lancashire and The Lakes	3.763488	6.789371	3.271032	3.835705	6.299839	3.420998	3.691271	7.278902	3.121066
15	South Lancashire, Yorkshire and Humber	5.365982	6.482783	0.555599	5.088175	6.025464	1.273196	5.643790	6.940104	-0.161997
16	North Midlands and North Wales	3.403190	3.837457	-0.400127	3.412973	3.699232	0.361583	3.393406	3.975682	-1.161837
17	South Lincolnshire and North Norfolk	2.278516	3.136903	0.145169	2.592731	3.287844	0.887254	1.964303	2.985963	-0.596914
18	Mid Wales and The Midlands	1.572176	2.638609	0.412657	2.014140	2.863863	1.086036	1.130212	2.413357	-0.260720
19	Anglesey and Snowdon	4.962246	5.282337	-0.546926	4.573119	4.691824	0.146158	5.351375	5.872851	-1.240008
20	Pembrokeshire	3.802694	1.324512	-4.144706	3.776698	1.771603	-2.584443	3.828692	0.877422	-5.704967
21	South Wales & Gloucester	-0.998891	-3.603250	-4.306933	-0.063268	-2.168165	-2.712760	-1.934514	-5.038336	-5.901106
22	Cotswold	-1.233828	-5.692285	-8.908485	-0.250548	-3.847097	-6.412958	-2.217106	-7.537472	-11.404010
23	Central London	-5.132933	-6.970638	-4.540565	-3.352794	-4.827185	-2.876028	-6.913069	-9.114090	-6.205102
24	Essex and Kent	-2.437621	-1.074585	0.794005	-1.199249	-0.117102	1.384869	-3.675993	-2.032068	0.203142
25	Oxfordshire, Surrey and Sussex	-2.202000	-2.873448	-1.821760	-1.017429	-1.568711	-0.715255	-3.386570	-4.178183	-2.928265
26	Somerset and Wessex	-5.082994	-6.477439	-2.751329	-3.324825	-4.456780	-1.461836	-6.841162	-8.498097	-4.040821
27	West Devon and Cornwall	-5.169371	-7.536723	-4.002209	-3.395391	-5.306954	-2.464188	-6.943351	-9.766492	-5.540231

Figure S1 Impact of variation in the Expansion Constant on Wider tariffs Comparison

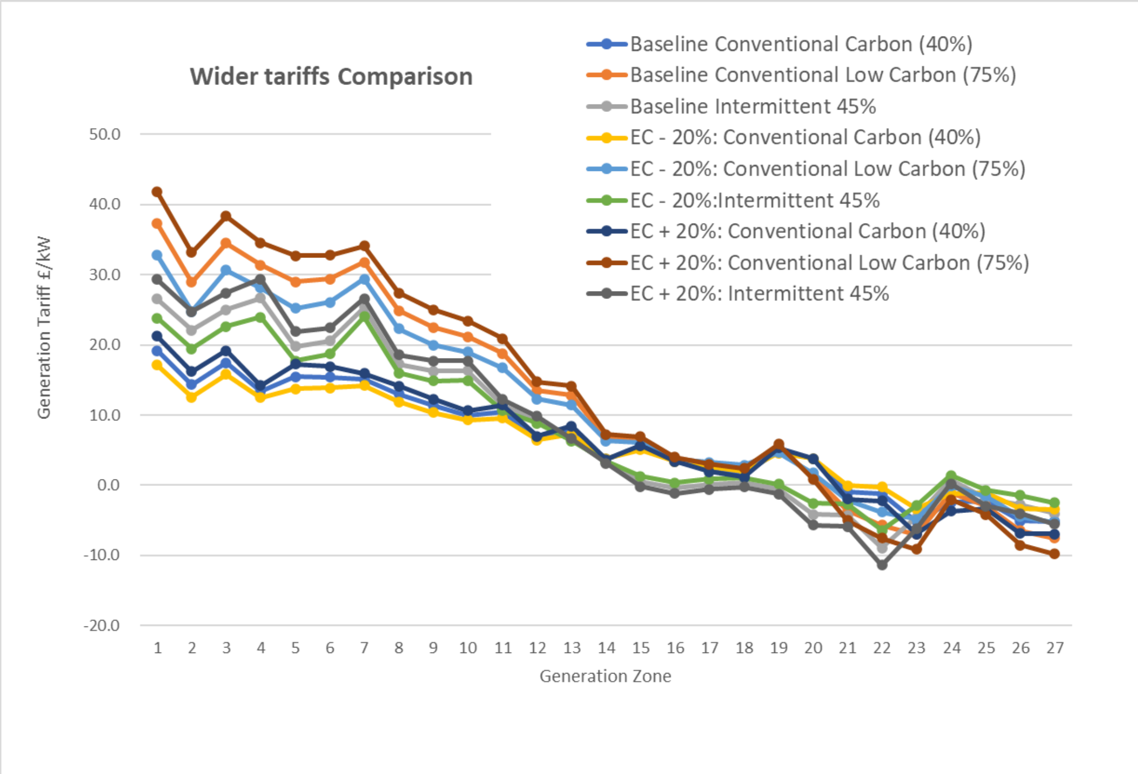


Table S2 Impact of variation in the Expansion Constant on HH Demand Tariffs in 2023/24

2023/24 HH Demand Tariffs		Baseline EC: HH Demand Tariff (£/kW)	EC - 20%: HH Demand Tariff (£/kW)	EC + 20%: HH Demand Tariff (£/kW)
Demand Zone				
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.000000	0.000000	0.000000
6	N Wales & Mersey	0.000000	0.000000	0.000000
7	East Midlands	0.000000	0.000000	0.000000
8	Midlands	0.547267	0.553231	0.541303
9	Eastern	0.000000	0.000000	0.000000
10	South Wales	3.972019	3.240278	4.703761
11	South East	2.905305	2.353124	3.457485
12	London	5.168789	4.148465	6.189114
13	Southern	5.504939	4.443912	6.565966
14	South Western	8.694899	7.009529	10.380269

Figure S2 Impact of variation in the Expansion Constant on HH Demand tariffs Comparison

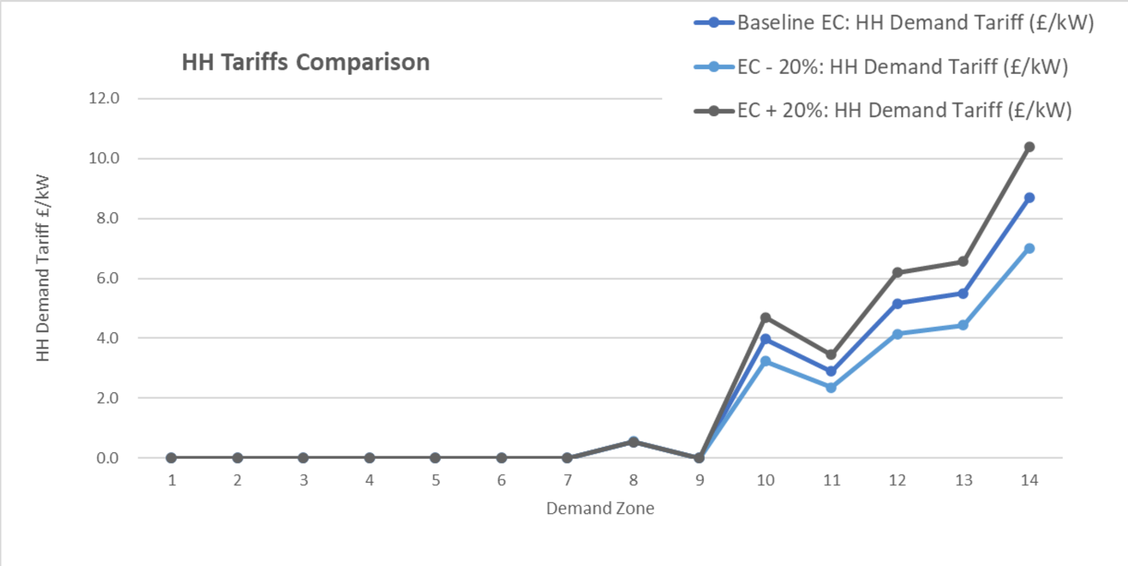


Table S3 Impact of variation in the Expansion Constant on NHH Demand Tariffs in 2023/24

2023/24 NHH Demand Tariffs				
Demand Zone		Baseline EC: NHH Demand Tariff (p/kWh)	EC - 20%: NHH Demand Tariff (p/kWh)	EC + 20%: NHH Demand Tariff (p/kWh)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.000000	0.000000	0.000000
6	N Wales & Mersey	0.000000	0.000000	0.000000
7	East Midlands	0.000000	0.000000	0.000000
8	Midlands	0.067926	0.068666	0.067186
9	Eastern	0.000000	0.000000	0.000000
10	South Wales	0.447363	0.364948	0.529778
11	South East	0.385372	0.312128	0.458615
12	London	0.514028	0.412559	0.615498
13	Southern	0.686977	0.554568	0.819385
14	South Western	1.174085	0.946507	1.401663

Figure S3 Impact of variation in the Expansion Constant on NHH Demand tariffs Comparison

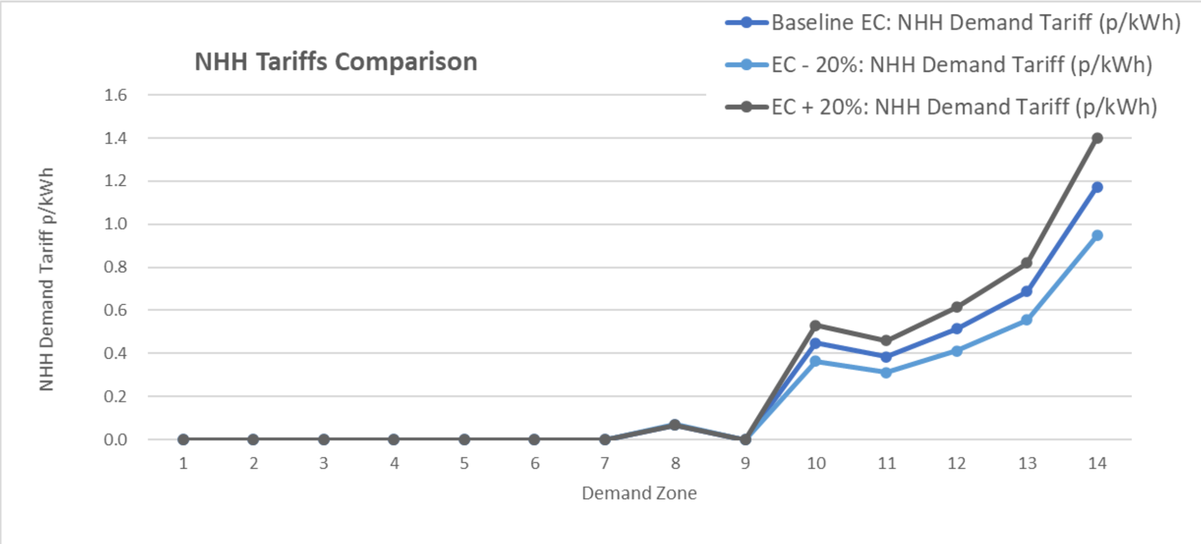
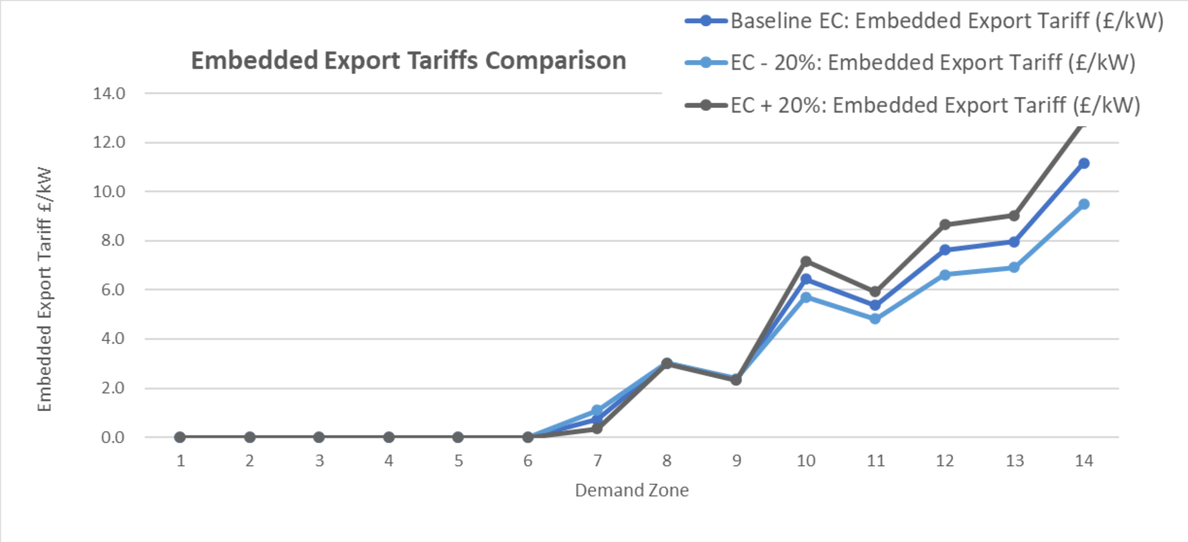


Table S4 Impact of variation in the Expansion Constant on Embedded Export Tariffs in 2023/24

2023/24 Embedded Export Tariffs Demand Zone		Baseline EC: Embedded Export Tariff (£/kW)	EC - 20%: Embedded Export Tariff (£/kW)	EC + 20%: Embedded Export Tariff (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.000000	0.000000	0.000000
6	N Wales & Mersey	0.000000	0.000000	0.000000
7	East Midlands	0.729141	1.108463	0.349818
8	Midlands	3.011853	3.017817	3.005889
9	Eastern	2.354156	2.381637	2.326675
10	South Wales	6.436605	5.704864	7.168347
11	South East	5.369891	4.817710	5.922071
12	London	7.633375	6.613051	8.653700
13	Southern	7.969525	6.908498	9.030552
14	South Western	11.159485	9.474115	12.844855

Figure S4 Impact of variation in the Expansion Constant on Embedded Export Tariffs Comparison



24. Impact of additional revenue on TDR

Following analysis of the impact of revenue changes in 2027/28 and 2023/24, it was evident that the impact from an increase or decrease in revenue had the same proportional effect regardless of the year. As such, this sensitivity analysis has only been shown on the year 2023/24 to avoid repetition.

The analysis also assumes the increase/decrease in revenue stems from onshore TOs or pass-through costs rather than OFTO revenue. This is because only a relatively small proportion of each OFTO's revenue impacts the revenue to be collected via the demand residual.

The total TDR charge/site is used as the measure because the impact on the individual site types is proportionately the same (i.e., each site increases/decreases by the same percentage).

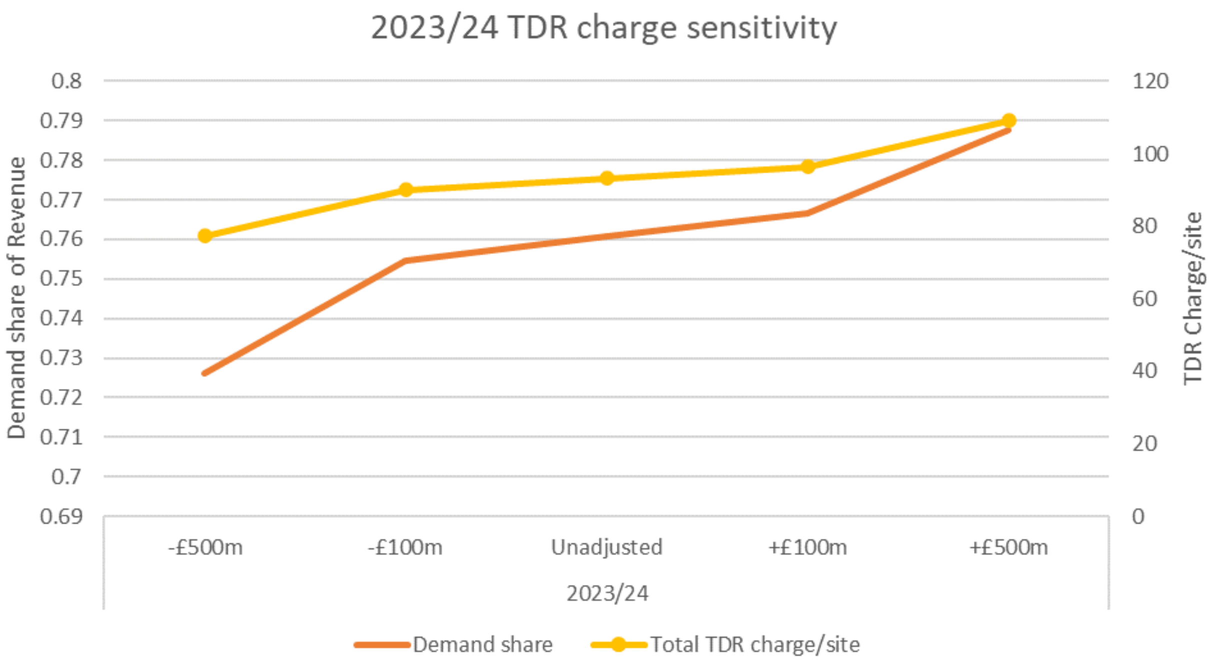
The 2023/24 Transport and Tariff model was run five times with a -£500m adjustment, -£100m adjustment, +£100m adjustment, +£500m adjustment and then no adjustment. The results of these runs can be seen in table S5 and figure S5 below.

Table S5 Impact of additional revenue on TDR

	2023/24				
	-£500m	-£100m	Unadjusted	+£100m	+£500m
Revenue (£m)	3,447	3,847	**3,947**	4,047	4,447
Generation Share	10.38%	9.30%	**9.07%**	8.84%	8.05%
Demand Share	72.61%	75.46%	**76.08%**	76.67%	78.77%
Connection Exclusion	17.01%	15.24%	**14.86%**	14.49%	13.18%
Total TDR charge/site	**£76.32**	**£88.91**	**£92.05**	**£95.20**	**£107.79**

Figure S5 Impact of additional revenue on TDR

The average 'total' TDR charge increases or decreases in line with the demand share of the revenue. As a broad rule of thumb, for every additional £100m of revenue, the average TDR charge/site will increase by ~3.4% whilst with every reduction of £100m of revenue, the average TDR charge/site will decrease by ~4.1%.



25. Impact of the Eastern HVDC (EHVDC) for 2027/28

Our customers have indicated that they would like to see the impacts of future generation and further HVDC links on TNUoS tariffs. Therefore, in this report, we have undertaken some sensitivity analysis around the proposed Eastern HVDC (EHVDC). The proposal for the Eastern HVDC projects consists of two separate reinforcement projects;

• Torness to Hawthorn Pit subsea HVDC link, expected to be operational from 2027; and

• Peterhead to Drax subsea HVDC link, expected to be operational from 2029.

We have included the Torness – Hawthorn Pit HVDC in the 2027/28 base case. In the sensitivity analysis, we have assessed two scenarios: (1) a delay to the Torness -Hawthorn Pit HVDC (referred to as phase 1) that leads to the 2027/28 network without the link, and (2) the Peterhead – Drax HVDC (referred to as phase 2) is "brough forward" into the 2027/28 network.

Table S6 shows the wider tariffs (four elements) under the two EHVDC scenarios. Table S7 and Figure S6 show the tariff comparison for a "typical" generator.

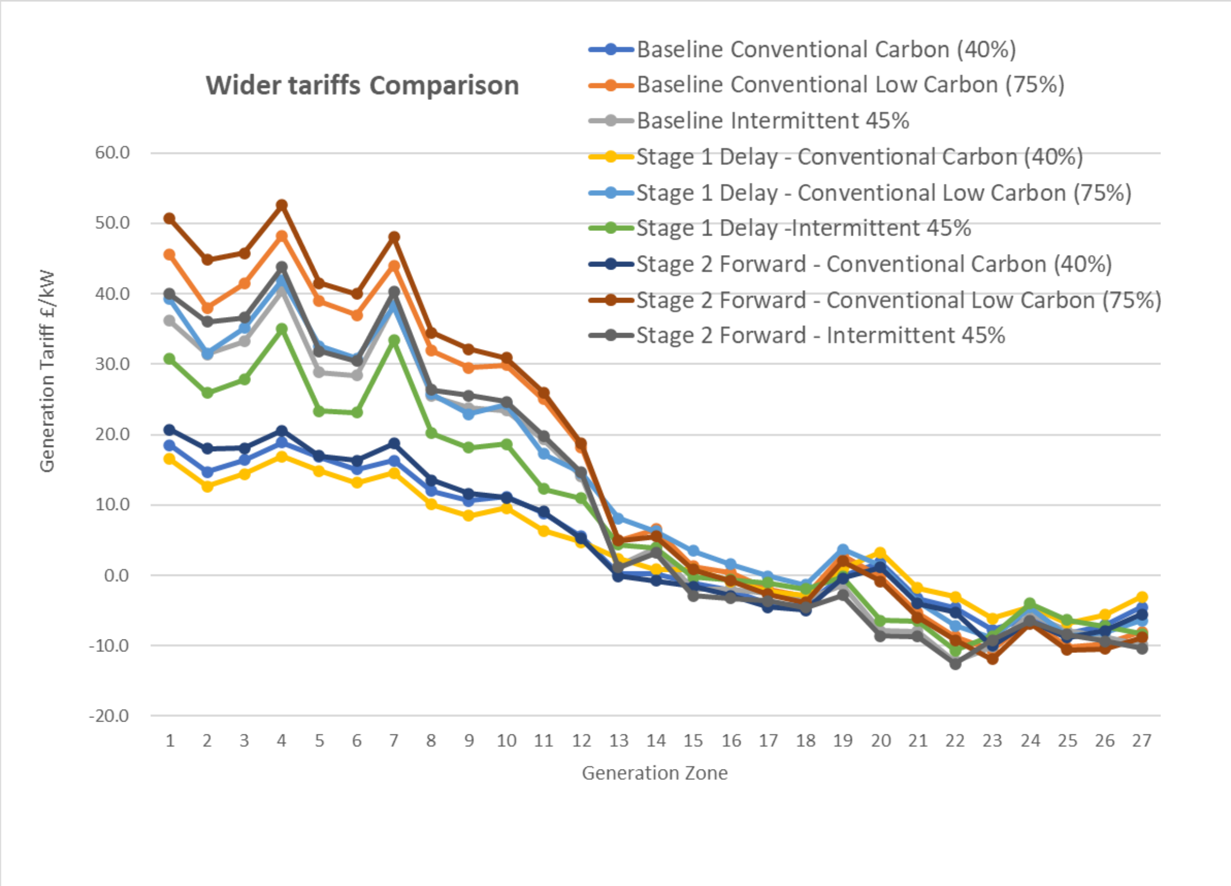
Table S6 Impact of the EHVDC for 2027/28 (wider tariffs)

Generation Zones		2027/28 without EHVDC stage 1				2027/28 with EHVDC stages 1 & 2			
Zone	Zone Name	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Adjustment (£/kW)	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Adjustment (£/kW)
1	North Scotland	1.457871	23.377302	24.161085	-3.940901	2.143549	28.399736	33.348732	-6.124993
2	East Aberdeenshire	1.854045	12.638428	24.161085	-3.940901	2.996744	19.475431	33.348732	-6.124993
3	Western Highlands	0.916812	21.314924	22.170908	-3.940901	1.400471	25.980541	31.014229	-6.124993
4	Skye and Lochalsh	0.555840	21.314924	29.315199	-3.940901	0.990790	25.980541	38.198620	-6.124993
5	Eastern Grampian and Tayside	3.941799	17.762705	19.264108	-3.940901	2.995573	22.229829	27.945002	-6.124993
6	Central Grampian	2.404695	17.628609	19.106940	-3.940901	3.082011	21.383924	26.953554	-6.124993
7	Argyll	0.080857	15.825452	30.222830	-3.940901	2.129522	18.851217	37.875935	-6.124993
8	The Trossachs	0.883958	15.825452	16.973736	-3.940901	2.497655	18.851217	23.957264	-6.124993
9	Stirlingshire and Fife	0.397345	14.520418	15.562443	-3.940901	1.082889	18.334024	23.397960	-6.124993
10	South West Scotlands	1.186659	14.837612	15.888016	-3.940901	0.947887	17.723520	22.771330	-6.124993
11	Lothian and Borders	0.535463	14.837612	9.514512	-3.940901	0.873872	17.723520	17.960471	-6.124993
12	Solway and Cheviot	0.162103	11.542011	9.686701	-3.940901	0.120927	13.425213	14.683230	-6.124993
13	North East England	1.067729	8.889098	4.325783	-3.940901	1.184421	8.814381	3.290237	-6.124993
14	North Lancashire and The Lakes	-0.306148	8.889098	3.828085	-3.940901	-0.290714	8.814381	5.365813	-6.124993
15	South Lancashire, Yorkshire and Humber	1.901663	6.283024	0.843227	-3.940901	2.066567	5.411930	0.819040	-6.124993
16	North Midlands and North Wales	0.484289	5.895988	0.633660	-3.940901	0.980320	5.038679	0.616936	-6.124993
17	South Lincolnshire and North Norfolk	-0.583351	5.158268	0.544643	-3.940901	-0.304743	4.297853	0.527545	-6.124993
18	Mid Wales and The Midlands	-0.449793	3.522115	0.383275	-3.940901	-0.012810	2.604735	0.360559	-6.124993
19	Anglesey and Snowdon	1.848737	6.895966	0.633660	-3.940901	3.057545	6.003080	0.616936	-6.124993
20	Pembrokeshire	9.415440	-5.447707	-	-3.940901	9.518455	-5.599397	-	-6.124993
21	South Wales & Gloucester	4.386384	-5.600928	-	-3.940901	4.459072	-5.744541	-	-6.124993
22	Cotswold	3.602135	-0.151314	-6.688572	-3.940901	3.671548	-0.850974	-6.073048	-6.124993
23	Central London	-0.284391	-0.151314	-4.583020	-3.940901	-2.469911	-0.850974	-2.697058	-6.124993
24	Essex and Kent	-0.534103	-0.151314	-	-3.940901	-0.101983	-0.850974	-	-6.124993
25	Oxfordshire, Surrey and Sussex	-0.667782	-5.348845	-	-3.940901	-0.713638	-4.955926	-	-6.124993
26	Somerset and Wessex	1.267592	-7.277594	-	-3.940901	1.113937	-7.217733	-	-6.124993
27	West Devon and Cornwall	4.843930	-9.779747	-	-3.940901	4.342580	-9.396481	-	-6.124993

Table S7 Impact of the EHVDC for 2027/28 (Tariffs Comparison)

Generation Zones		2027/28 Baseline (with EHVDC stage 1)			2027/28 Sensitivity (without EHVDC Stage 1)			2027/28 Sensitivity (with EHVDC stages 1&2)		
Zone	Zone Name	Conventional Carbon (40%)	Conventional Low Carbon (75%)	Intermittent 45%	Conventional Carbon (40%)	Conventional Low Carbon (75%)	Intermittent 45%	Conventional Carbon (40%)	Conventional Low Carbon (75%)	Intermittent 45%
1	North Scotland	18.517701	45.536621	36.186296	16.532325	39.211032	30.739970	20.717943	50.667090	40.003620
2	East Aberdeenshire	14.663715	37.965661	31.407330	12.632949	31.553050	25.907477	18.001416	44.827056	35.987683
3	Western Highlands	16.355444	41.457535	33.266693	14.370244	35.133012	27.821723	18.073386	45.775113	36.580479
4	Skye and Lochalsh	18.852066	48.240500	40.410597	16.866988	41.916331	34.966014	20.537461	52.549823	43.764870
5	Eastern Grampian and Tayside	16.823597	38.967749	28.805760	14.811623	32.587035	23.316424	16.940512	41.487954	31.823432
6	Central Grampian	15.083835	36.974533	28.415423	13.158014	30.792191	23.098913	16.292009	39.948515	30.451327
7	Argyll	16.327940	44.019385	38.327277	14.559269	38.231875	33.403382	18.695390	48.018877	40.233990
8	The Trossachs	11.967982	31.919662	25.427668	10.062732	25.785882	20.154288	13.496054	34.468339	26.315319
9	Stirlingshire and Fife	10.580270	29.475500	23.807940	8.489588	22.909201	18.155730	11.650690	32.106374	25.523278
10	South West Scotlands	11.191255	29.834612	23.422921	9.536009	24.261983	18.624040	11.020834	30.886864	24.621921
11	Lothian and Borders	8.830437	24.996737	19.294493	6.335412	17.237283	12.250536	9.022475	26.001990	19.811062
12	Solway and Cheviot	5.554225	18.240572	14.031597	4.712687	14.564411	10.939705	5.239311	18.748074	14.599583
13	North East England	0.156824	4.914371	1.363769	2.412780	8.119435	4.384976	-0.098725	4.960451	1.131715
14	North Lancashire and The Lakes	0.276771	6.555008	3.898253	0.839824	6.247860	3.887278	-0.743629	5.560892	3.207291
15	South Lancashire, Yorkshire and Humber	-1.145964	1.314855	-2.022201	0.811262	3.516257	-0.270313	-1.566038	0.819562	-2.870585
16	North Midlands and North Wales	-2.153687	0.380634	-1.914220	-0.844753	1.599039	-0.654046	-2.882427	-0.748728	-3.240651
17	South Lincolnshire and North Norfolk	-3.962113	-1.959055	-2.631960	-2.243088	-0.110908	-1.075037	-4.499577	-2.678801	-3.663414
18	Mid Wales and The Midlands	-4.346778	-2.985101	-3.491929	-2.828538	-1.365833	-1.972674	-4.951685	-3.823693	-4.592303
19	Anglesey and Snowdon	-0.009483	2.924458	-1.400423	0.919686	3.713471	-0.204056	-0.419442	2.051798	-2.806671
20	Pembrokeshire	1.835350	-0.162924	-7.900005	3.295456	1.388759	-6.392369	1.153703	-0.806086	-8.644722
21	South Wales & Gloucester	-3.261284	-5.313277	-7.969074	-1.794888	-3.755213	-6.461319	-3.963737	-5.974327	-8.710036
22	Cotswold	-4.551550	-8.700773	-12.183991	-3.074720	-7.140824	-10.697564	-5.223054	-9.164724	-12.580979
23	Central London	-7.713681	-10.631876	-10.132277	-6.119026	-8.921798	-8.592012	-10.014117	-11.930193	-9.204989
24	Essex and Kent	-6.133057	-6.296272	-5.540643	-4.535530	-4.588490	-4.008992	-6.567366	-6.865207	-6.507931
25	Oxfordshire, Surrey and Sussex	-8.277200	-10.251277	-7.868895	-6.748221	-8.620317	-6.347881	-8.821001	-10.555576	-8.355160
26	Somerset and Wessex	-7.081882	-9.726294	-8.730754	-5.584347	-8.131505	-7.215818	-7.898149	-10.424356	-9.372973
27	West Devon and Cornwall	-4.500906	-8.020746	-9.856305	-3.008870	-6.431781	-8.341787	-5.541005	-8.829774	-10.353409

Figure S6 Impact of EHVDC – tariffs comparison



26. Impact of links to Scottish Isles becoming part of the wider network for 2027/28

There is a scenario that Grid Supply Points (GSPs) could be built on remote islands, at the remote end of island links (for example, Shetland link and Western Isles link). In this sensitivity, we have assessed the indicative tariffs under this scenario, where the remote island links would become part of the wider network (and thus affect wider tariffs) due to the definition of MITS node under the CUSC. The sensitivity analysis was undertaken on the 2027/28 model. The tariff impacts in other years would be similar.

We have assumed these links would be included in generation zone 1, and therefore impact zone 1 and zone 2 tariffs (in addition to the Adjustment Tariff). We have not included re-zoning in the sensitivity (where the remote islands are separated from generation zone 1 and become zones of their own), as generation zoning interacts with CMP315/375.

Table S8 Impact of links to Scottish Isles becoming part of the wider network for 2027/28

Generation Zones		2027/28 Baseline				2027/28 Sensitivity (with island links become part of the wider network)			
Zone	Zone Name	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Adjustment (£/kW)	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Adjustment (£/kW)
1	North Scotland	1.442833	26.358306	29.655854	- 5.330796	1.442833	30.342647	33.514767	- 5.658346
2	East Aberdeenshire	1.836816	15.738383	29.655854	- 5.330796	1.836816	11.864903	33.514767	- 5.658346

Tools and supporting information

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

Charging webinars

We will be hosting a webinar for the five-year view on Thursday 14th April. 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/248601/download

This data can also be accessed via our Data Portal:

https://data.nationalgrideso.com/network-charges/transmission-network-use-of-system-tnuos-tariffs

Allow for 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

nationalgridESO

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 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, NGESO 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 replacing 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.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational “residual” elements are included in the generation and demand tariffs. The demand residual banded charges for demand, and adjustment tariff for generation, is also used to ensure the correct proportion of revenue is collected from demand and generation. The locational and adjustment tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff. From April 2023, demand will have locational HH and NHH demand tariffs split across demand zones and with approval of CMP343 ‘demand residual banded charges’ the demand residual element is charged across a range of banded annual site charges for HH and NHH demand.

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 revenue allowances.

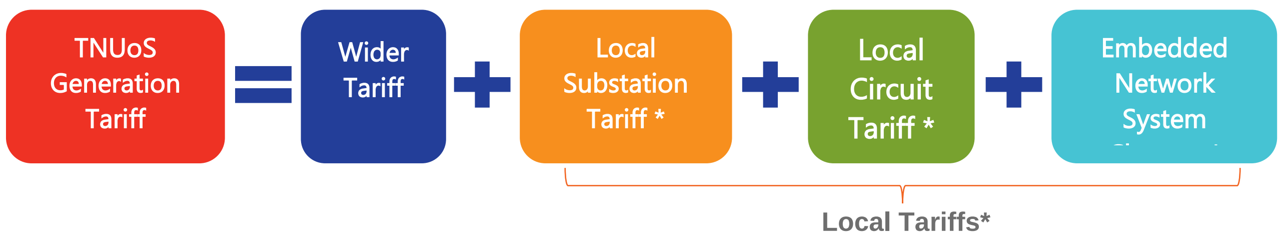
Generation charging principles

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**.



** Additional Local Tariffs may be applicable to Offshore generators*

The Wider tariff is set to recover 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.

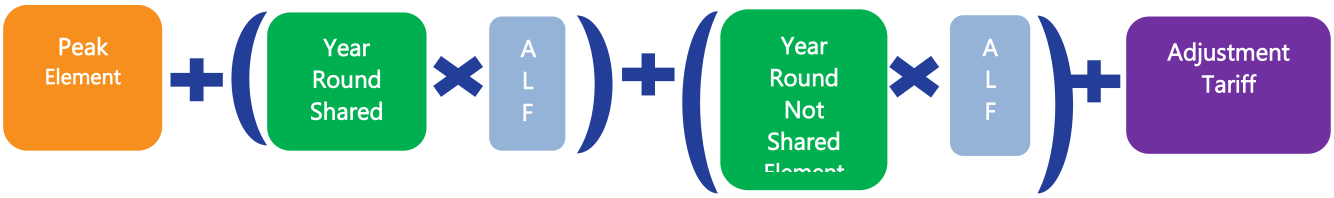
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

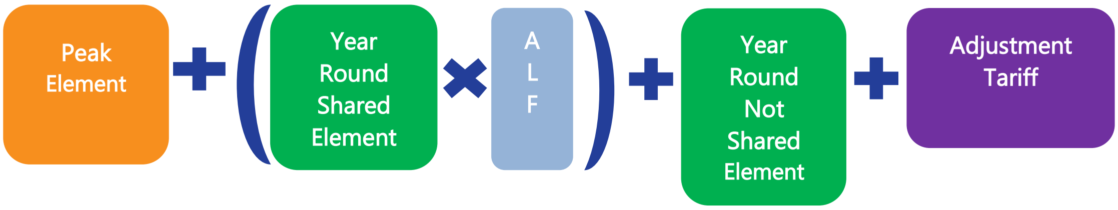
Conventional Carbon Generators

(Biomass, CHP, Coal, Gas, Pump Storage)



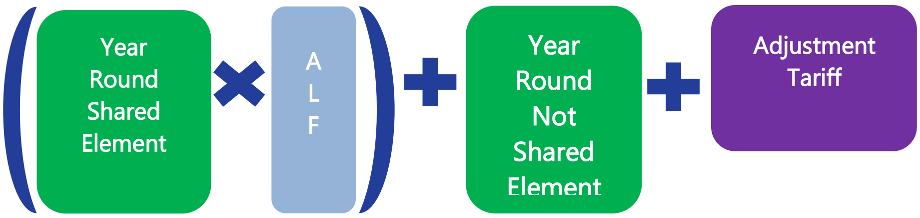
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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 derived from the generic ALF calculated for that generator type.

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

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

Local substation tariffs

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

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

Local circuit tariffs

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

Embedded network system charges

If a generator is not connected directly to the transmission network, they need to have a BEGA[11] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[12] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Click here to find out more about DNO regions.

Offshore local tariffs

Where an offshore generator's connection 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

TNUoS is charged annually 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 liability 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 each month for the month ahead.

[11] Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: https://www.nationalgrid.com/uk/electricity/connections/applying-connection

[12] 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 for 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 two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff. With the implementation of CMP343, the demand residual element of the demand charges are to be split out (previously included in the HH and NHH locational charges) and an additional set off banded charges are to apply to HH and NHH demand.

HH gross demand tariffs

HH gross demand tariffs are made up of locational charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[13] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data are available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[14], however this will need to be updated with the introduction of CMP343 and the demand residual banded charges. This guidance will be updated in due course.

Embedded Export Tariffs (EET)

The EET was introduced under CMP264/265 and 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 for the avoidance of 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 demand tariffs.

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

For more information on forecasts and billing, please see our guide for new suppliers on our website[15].

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

[13] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data

[14] https://www.nationalgrideso.com/document/130641/download

[15] https://www.nationalgrideso.com/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 banded charges (CMP343)

With recent decision made by Ofgem for CMP343 the new demand residual banded charging methodology is to be implemented from April 2023.

Appendix B: Proposed changes to the charging methodology

nationalgridESO

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 tariff calculation methodology for 2023/24 – 2027/28. Each modification is subject to an approval decision by Ofgem and if any Work Group Alternative CUSC Modifications (WACM) have been raised then Ofgem will decide which, if any, are approved.

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

https://www.nationalgrideso.com/uk/electricity/codes/connection-and-use-system-code?mods

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

Table 27 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP286/287	Improving TNUoS Predictability Through Increased Notice	Increase notice period of tariff setting input data	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
CMP315/ CMP375	TNUoS: Review of the expansion constant and the elements of the transmission system charge	Affect TNUoS locational tariffs for generators and demand users	
CMP316	TNUoS Arrangements for Co-located Generation Sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types. Affects TNUoS locational tariffs.	
CMP330/374	Allowing new Transmission Connected parties to build Connection Assets greater than 2km in length	Change CUSC section 14 to enable connection assets greater than 2km in length	
CMP331	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.	
CMP368/369	Charges for the Physical Assets Required for Connection	Part of the Transmission Generation Residual (TGR)	
CMP379	Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)	Determine demand zones for transmission-connected demand users at multiple DNO sites	

CMP384	Apply adjustments for inflation to manifest error thresholds using Indexation	Applying inflation to the manifest error thresholds	

* We have not included the CUSC mods 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. Ultimately, 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

nationalgridESO

Locational components of demand tariffs

The following tables show the locational components of the 'now referred to as' locational HH demand charge (Peak and Year-Round) for each year of the forecast. With the introduction of CMP343 and the removal of the demand residual (demand residual tariff) from HH tariffs, the locational elements combined which make up the HH demand tariff have been floored to £0/kW where only positive tariffs are applied. Prior to April 2023 implementation of CMP343 the inclusion of the demand residual tariff has meant all zonal tariffs have been positive.

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 floored at zero to avoid negative tariffs (charges).

Table 28 Locational elements of the HH demand tariff for 2023/24

Demand Zone		2023/24		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.600906	-29.132269	0.000000
2	Southern Scotland	-2.795621	-20.364090	0.000000
3	Northern	-4.079732	-8.925711	0.000000
4	North West	-1.250935	-4.689908	0.000000
5	Yorkshire	-2.961623	-2.741055	0.000000
6	N Wales & Mersey	-2.100891	-1.944674	0.000000
7	East Midlands	-2.676694	0.941249	0.000000
8	Midlands	-1.551307	2.098574	0.547267
9	Eastern	0.903026	-1.013456	0.000000
10	South Wales	-3.566135	7.538154	3.972019
11	South East	3.261132	-0.355827	2.905305
12	London	5.023047	0.145743	5.168789
13	Southern	1.708529	3.796411	5.504939
14	South Western	1.585107	7.109792	8.694899

Table 29 Locational elements of the HH demand tariff for 2024/25

Demand Zone		2024/25		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-2.589490	-30.620176	0.000000
2	Southern Scotland	-3.169755	-21.671985	0.000000
3	Northern	-3.854009	-9.306101	0.000000
4	North West	-1.871817	-4.827373	0.000000
5	Yorkshire	-2.914105	-3.280788	0.000000
6	N Wales & Mersey	-2.816927	-2.675186	0.000000
7	East Midlands	-2.629338	0.851626	0.000000
8	Midlands	-2.030524	2.099222	0.068698
9	Eastern	0.694119	-1.756381	0.000000
10	South Wales	-3.501508	7.644415	4.142908
11	South East	3.725246	-0.081576	3.643670
12	London	4.215976	-1.337304	2.878672
13	Southern	2.101557	4.342434	6.443991
14	South Western	2.534147	8.320627	10.854774

Table 30 Locational elements of the HH demand tariff for 2025/26

Demand Zone		2025/26		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-1.701186	-32.922432	0.000000
2	Southern Scotland	-2.031586	-23.514303	0.000000
3	Northern	-2.653139	-10.780108	0.000000
4	North West	-0.914787	-6.443152	0.000000
5	Yorkshire	-1.802102	-4.550496	0.000000
6	N Wales & Mersey	-1.216126	-4.854615	0.000000
7	East Midlands	-1.856844	-0.003007	0.000000
8	Midlands	-1.412300	0.993409	0.000000
9	Eastern	0.040316	-1.250034	0.000000
10	South Wales	-4.576036	7.549039	2.973003
11	South East	2.979654	0.887459	3.867113
12	London	3.370413	-0.473634	2.896779
13	Southern	1.502492	5.186212	6.688704
14	South Western	0.832374	9.786529	10.618903

Table 31 Locational elements of the HH demand tariff for 2026/27

Demand Zone		2026/27		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	-1.085579	-35.011209	0.000000
2	Southern Scotland	-1.700116	-24.970955	0.000000
3	Northern	-2.291198	-11.624270	0.000000
4	North West	-0.601766	-7.150370	0.000000
5	Yorkshire	-1.440884	-5.341860	0.000000
6	N Wales & Mersey	-0.653854	-5.411539	0.000000
7	East Midlands	-1.575139	-0.687754	0.000000
8	Midlands	-0.977576	0.334885	0.000000
9	Eastern	-0.057525	-1.074702	0.000000
10	South Wales	-4.723103	7.453008	2.729905
11	South East	2.195339	1.261621	3.456960
12	London	3.444275	0.738513	4.182788
13	Southern	1.134816	5.307376	6.442192
14	South Western	0.249834	10.055559	10.305393

Table 32 Locational elements of the HH demand tariff for 2027/28

Demand Zone		2027/28		
		Peak (£/kW)	Year Round (£/kW)	Floored HH Tariff (£/kW)
1	Northern Scotland	0.144388	-46.051692	0.000000
2	Southern Scotland	-0.330437	-35.652168	0.000000
3	Northern	-0.690132	-12.299210	0.000000
4	North West	0.299755	-8.925514	0.000000
5	Yorkshire	0.208860	-6.934897	0.000000
6	N Wales & Mersey	0.110869	-7.677595	0.000000
7	East Midlands	-0.125583	-1.835769	0.000000
8	Midlands	-0.384591	-0.623326	0.000000
9	Eastern	0.604224	-0.587142	0.017082
10	South Wales	-5.249669	6.529049	1.279380
11	South East	0.679061	4.158419	4.837480
12	London	1.579190	4.353095	5.932285
13	Southern	0.495779	6.511316	7.007095
14	South Western	-2.636533	8.739647	6.103114

Appendix D: Annual Load Factors

nationalgridESO

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 2022/23 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2016/17 to 2020/21. Generators which commissioned after 1 April 2018 will have fewer than three complete years of data, so the appropriate Generic ALF listed below is added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2022/23 also use the Generic ALF for their first three years of operation.

The specific and generic ALFs that will apply to the 2023/24 TNUoS Tariffs will be updated by our Draft Tariffs publication in November 2022. The specific and generic ALFs for 2022/23 tariffs, as used in this forecast are published here, with specific ALFs in excel format here.

Generic ALFs

Table 33 Generic ALFs

Technology	Generic ALF
Gas_Oil	0.4627%
Pumped_Storage	9.0321%
Tidal	12.8000%
Biomass	43.1684%
Wave	2.9000%
Onshore_Wind	35.5062%
CCGT_CHP	51.3589%
Hydro	40.9203%
Offshore_Wind	48.2161%
Coal	14.0552%
Nuclear	70.2612%
Solar	10.9000%

*Note: ALF figures for Wave, Tidal and Solar technology are generic figures provided by BEIS due to no metered data being available.

These Generic ALFs are calculated in accordance with CUSC 14.15.110.

Appendix E: Contracted generation

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

For the complete breakdown of Contracted TEC per generator for each year, please see Table A Contracted TEC by Generator in the Tables spreadsheet published on our website here, under 5-Year View Tariff Publications. The data in Table 34 is taken from the TEC register from February 2022.

The contracted generation used in the Transport model will be fixed in the November Draft forecast of 2023/24 tariffs, using the TEC register as of 31 October 2022, as specified by the CUSC 14.15.6.

Table 34 Contracted TEC by generation zone

Zone	Zone Name	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)	2026/27 (MW)	2027/28 (MW)
1	North Scotland	2,425	3,968	5,120	7,239	8,584
2	East Aberdeenshire	2,080	2,080	2,080	3,480	3,585
3	Western Highlands	488	488	488	589	1,201
4	Skye and Lochalsh	41	41	91	331	331
5	Eastern Grampian and Tayside	1,358	1,526	1,726	1,865	1,865
6	Central Grampian	64	64	64	64	64
7	Argyll	166	166	373	574	724
8	The Trossachs	520	520	520	520	520
9	Stirlingshire and Fife	120	670	670	670	1,170
10	South West Scotland	2,484	3,434	4,061	4,545	5,028
11	Lothian and Borders	4,341	6,374	6,931	9,103	10,003
12	Solway and Cheviot	451	501	1,251	1,335	1,487
13	North East England	6,077	7,737	7,794	9,504	12,069
14	North Lancashire and The Lakes	4,189	4,189	4,189	4,189	4,189
15	South Lancashire, Yorkshire and Humbe	10,859	12,968	15,968	18,358	20,858
16	North Midlands and North Wales	11,165	10,986	12,956	14,933	16,288
17	South Lincolnshire and North Norfolk	6,508	6,558	10,658	10,658	10,658
18	Mid Wales and The Midlands	7,548	10,775	17,426	19,589	21,630
19	Anglesey and Snowdon	1,644	2,121	2,121	2,601	2,601
20	Pembrokeshire	2,549	3,053	3,053	3,839	3,839
21	South Wales & Gloucester	2,191	2,440	2,790	3,010	3,022
22	Cotswold	1,511	1,561	1,561	1,561	1,561
23	Central London	194	194	251	251	258
24	Essex and Kent	14,591	19,061	20,990	21,068	23,275
25	Oxfordshire, Surrey and Sussex	2,723	2,986	5,183	7,230	7,344
26	Somerset and Wessex	3,479	3,867	7,036	8,777	9,226
27	West Devon and Cornwall	1,195	1,245	1,295	3,095	3,095

Appendix F: Maximum Allowed Revenues

Transmission Owner revenue forecasts

In this report, the revenue forecasts are based on figures submitted in January by all onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs. The revenue forecast for 2023/24 will be updated later this year. In addition, there are some pass-through items that are to be collected by NGESO via TNUoS charges, including Licence fees, the Strategic Innovation Fund (SIF), Interconnector contributions, and site-specific adjustments by TOs etc, and these figures would also be updated in November and January.

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

Notes:

All monies are quoted in millions of pounds, accurate to two decimal place 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. NGESO 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 NGESO 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.

NGESO TNUoS revenue pass-through items forecasts

From April 2019, a new, legally separate electricity system operator (NGESO) was established within National Grid Group, separate from National Grid Electricity Transmission (NGET). As a result, the allowed TNUoS revenue under NGET's licence, is collected by NGESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In addition, NGESO collects the Strategic Innovation Fund (SIF), and passes through the money to network licensees (including TOs, OFTOs and DNOs). There are also a few miscellaneous pass-through items that had been collected by NGET under its licence condition, and this function was also transferred to NGESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under NGESO's licence conditions.

At this point in time NGESO components are not anticipated to vary across the years with the exception of the Network Innovation Competition Fund (NICFt) and the Strategic Innovation Fund (SIFt). NICFt payments are still being made due to the way the funds are administered but are believed to reduce with an eventual end in 2024/25. SIFt payments are expected to continue increasing as more projects begin and reach the next stage of funding (which increases as the project matures). These values will be reviewed again in the August forecast.

Table 35 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through 2023/24	2024/25	2025/26	2026/27	2027/28
Embedded Offshore Pass-Through (OFETt)	0.70	0.70	0.70	0.70	0.70
Network Innovation Competition Fund (NICFt)	12.85	3.00	0.00	0.00	0.00
Strategic Innovation Fund (SIFt)	25.25	27.78	30.55	33.61	36.97
The Adjustment Term (ADJt)	4.24	0.00	0.00	0.00	0.00
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	735.19	800.32	887.61	959.05	1,051.05
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	0.00	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00	0.00	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	1,991.59	1,995.23	1,995.90	2,035.82	2,076.53
SPT revenue pass-through (TSPt)	421.23	430.61	420.54	428.95	437.53
SHETL revenue pass-through (TSHt)	712.36	801.90	759.74	740.00	758.50
ESO Bad debt (BDt)	3.60	3.60	3.60	3.60	3.60
ESO other pass-through items (LFt + ITCt etc)	40.33	40.33	40.33	40.33	40.33
ESO legacy adjustment (LARt)	0.00	0.00	0.00	0.00	0.00
Total	**3,947.34**	**4,103.46**	**4,138.95**	**4,242.04**	**4,405.20**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their 5-year forecast of revenue breakdown for 2023/24 to 2027/28. Notably payments associated with RIIO-ET1 are now closed, the values submitted of 0 by the TOs have been left in the tables below for confirmation.

SHET anticipate increasing costs due to the increased expenditure required for delivery of their business plan portfolio. These will peak in 2024/2025 before decreasing to below 2023/24 levels in 2026/27. Similarly, NGET and SPT figures remain stable but impacted by inflation with no notable increases or decreases.

At this point the year 2026/27 to 2027/28 are consistent with the RIIO-ET2 methodology despite falling in RIIO-ET3's price control period. This is because the underlying assumptions are as yet unknown.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2023/24is forecast to be £719m, increasing by £291m to £1,011m in 2027/28. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence). The 2023/24 forecast includes £167m of forecast revenue (23% of total) for OFTOs yet to asset transfer whilst 2027/28 includes £392m of revenue (39% of total) for OFTOs yet to asset transfer.

Since 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework, and interconnectors' Cap & Floor framework. The contribution forecast from interconnectors have been aggregated with ESO's forecast on future OFTO revenue.

Table 36 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission					Notes
			2023/24	2024/25	2025/26	2026/27	2027/28	
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	324.73	331.39	338.02	344.78	351.68	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,737.57	1,705.73	1,672.82	1,672.82	1,672.82	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	A	$ADJR_t$	1,991.59	1,995.23	1,995.90	2,035.82	2,076.53	
SONIA	B1	It-1	0.01	0.01	1.14%	1.00%	1.00%	
Allowed Revenue	B2	ARt-1	1,795.07	1,991.59	1,995.23	1,995.90	1,995.90	
Recovered Revenue	B4	RRt-1	1,795.07	1,991.59	1,995.23	1,995.90	1,995.90	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	B	K_t	0.00	0.00	0.00	0.00	0.00	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	0.00	0.00	0.00	
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	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	0.00	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	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	0.00	0.00	
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	C	LAR_t	0.00	0.00	0.00	0.00	0.00	
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	D	AR_t	1,991.59	1,995.23	1,995.90	2,035.82	2,076.53	

Table 37 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission					Notes
			2023/24	2024/25	2025/26	2026/27	2027/28	
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	324.73	331.39	338.02	344.78	351.68	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	367.50	368.13	352.46	352.46	352.46	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	421.23	430.61	420.54	428.95	437.53	
SONIA	B1	It-1	0.01	0.01	1.14%	1.00%	1.00%	
Allowed Revenue	B2	ARt-1	0.00	0.00	0.00	0.00	0.00	
Recovered Revenue	B4	RRt-1	0.00	0.00	0.00	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	0.00	0.00	0.00	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	0.00	0.00	0.00	
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	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	0.00	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	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	0.00	0.00	
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	C	LAR_t	0.00	0.00	0.00	0.00	0.00	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	421.23	430.61	420.54	428.95	437.53	

Table 38 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission 2023/24	2024/25	2025/26	2026/27	2027/28	Notes
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	324.73	331.39	338.02	344.78	351.68	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	621.50	685.54	636.76	608.06	611.04	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	0.00	0.00	0.00	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	712.36	801.90	759.74	740.00	758.50	
SONIA	B1	It-1	0.01	0.01	1.14%	1.00%	1.00%	
Allowed Revenue	B2	ARt-1	673.24	712.36	801.90	759.74	740.00	
Recovered Revenue	B4	RRt-1	673.24	712.36	801.90	759.74	740.00	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	0.00	0.00	0.00	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	0.00	0.00	0.00	
Legacy K correction	C3	LKt	0.00	0.00	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	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	0.00	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	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	0.00	0.00	
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	C	LAR_t	0.00	0.00	0.00	0.00	0.00	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	712.36	801.90	759.74	740.00	758.50	

Table 39 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	Year						
Regulatory Year	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	Notes
Barrow	7.0	7.5	7.7	7.9	8.1	8.4	Current revenues plus indexation
Gunfleet	8.7	9.3	9.6	9.9	10.2	10.4	Current revenues plus indexation
Walney 1	15.6	16.9	17.5	18.0	18.5	19.0	Current revenues plus indexation
Robin Rigg	9.8	10.5	10.8	11.1	11.4	11.7	Current revenues plus indexation
Walney 2	16.3	17.5	18.0	18.6	19.1	19.7	Current revenues plus indexation
Sheringham Shoal	24.2	25.7	26.5	27.4	28.2	28.9	Current revenues plus indexation
Ormonde	14.7	15.7	16.2	16.6	17.1	17.6	Current revenues plus indexation
Greater Gabbard	33.2	35.5	36.4	37.7	38.8	39.0	Current revenues plus indexation
London Array	46.8	49.5	50.9	52.4	53.9	55.0	Current revenues plus indexation
Thanet	21.6	23.0	23.8	24.5	25.2	25.4	Current revenues plus indexation
Lincs	32.5	34.1	35.1	36.0	37.1	38.1	Current revenues plus indexation
Gwynt y mor	39.8	33.3	34.3	35.3	36.4	37.5	Current revenues plus indexation
West of Duddon Sands	25.5	26.9	27.7	28.5	29.4	30.2	Current revenues plus indexation
Humber Gateway	13.3	14.4	14.8	15.3	15.7	16.1	Current revenues plus indexation
Westermost Rough	14.7	15.7	16.2	16.6	17.1	17.6	Current revenues plus indexation
Burbo Bank	14.7	15.7	16.1	16.6	17.1	17.6	Current revenues plus indexation
Dudgeon	20.8	22.2	22.8	23.5	24.2	24.9	Current revenues plus indexation
Race Bank	28.9	30.8	31.7	32.7	33.6	34.7	Current revenues plus indexation
Galloper	17.8	19.0	19.6	20.2	20.8	21.4	Current revenues plus indexation
Walney 3	14.1	15.1	15.5	16.0	16.5	17.0	Current revenues plus indexation
Walney 4	14.1	15.1	15.5	16.0	16.5	17.0	Current revenues plus indexation
Hornsea 1A	18.4	19.6	20.2	20.8	21.5	22.1	Current revenues plus indexation
Hornsea 1B	18.4	19.6	20.2	20.8	21.5	22.1	Current revenues plus indexation
Hornsea 1C	18.4	19.6	20.2	20.8	21.5	22.1	Current revenues plus indexation
Beatrice	21.1	23.2	23.9	24.6	25.3	26.0	Current revenues plus indexation
Rampion	15.7	17.2	17.7	18.3	18.8	19.3	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2022/23	71.0	138.7	142.8	147.1	151.5	156.1	NGESO Forecast
Forecast to asset transfer to OFTO in 2023/24		28.0	47.5	48.9	50.4	51.9	NGESO Forecast
Forecast to asset transfer to OFTO in 2024/25			0.0	0.0	0.0	0.0	NGESO Forecast
Forecast to asset transfer to OFTO in 2025/26				56.9	97.3	100.2	NGESO Forecast
Forecast to asset transfer to OFTO in 2026/27					16.4	28.8	NGESO Forecast
Forecast to asset transfer to OFTO in 2027/28						54.8	NGESO Forecast
Offshore Transmission Pass-Through (B7)	597.2	719.3	759.4	839.1	919.0	1,010.7	

Notes:

Figures for historic years represent National Grid's forecast of OFTO revenues at the time final tariffs were calculated for each charging year rather than our current best view.

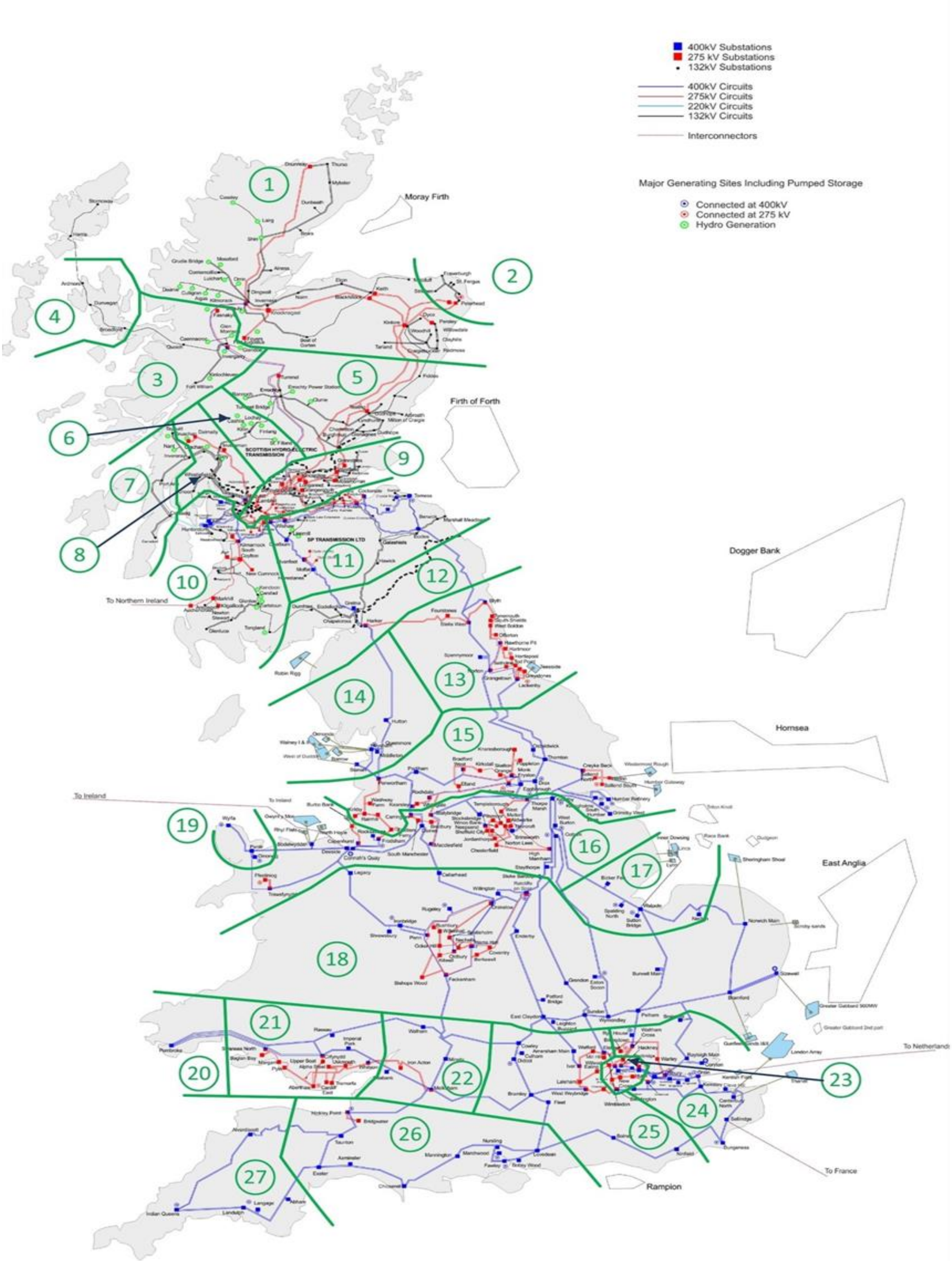
Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders

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

Appendix G: Generation zones map

Appendix G: Generation zones map

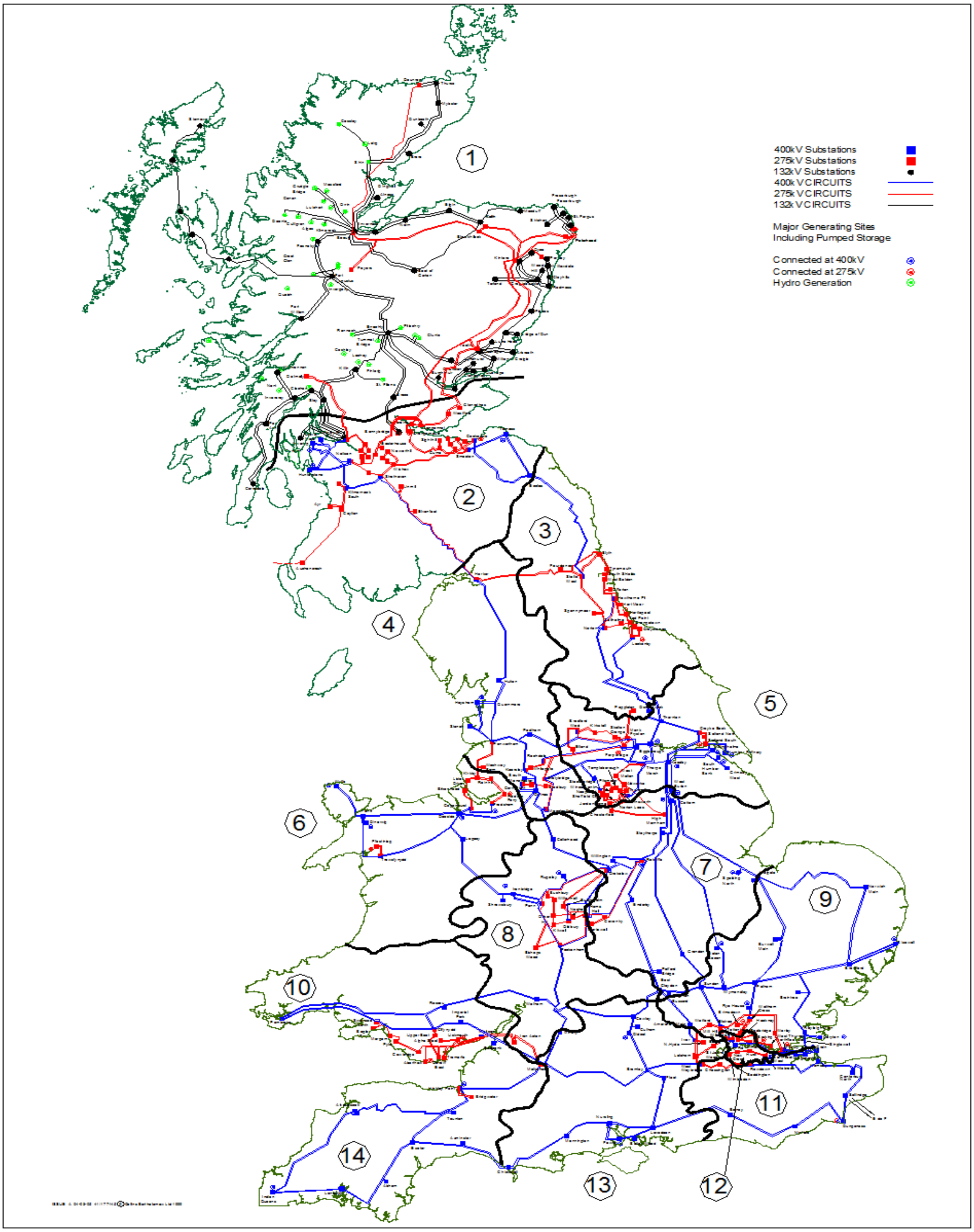
Figure A2: GB Existing Transmission System



Appendix H: Demand zones map

nationalgridESO

Appendix H: Demand zones map



Appendix I: Changes to TNUoS parameters

Parameters affecting TNUoS tariffs

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.

2023/24 TNUoS Tariff Forecast					
		April 2022	August 2022	Draft Tariffs November 2022	Final Tariffs January 2023
Methodology		*Open to industry governance*			
LOCATIONAL	DNO/DCC Demand Data	Initial update using previous year's data source		Week 24 updated	
LOCATIONAL	Contracted TEC	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October	
LOCATIONAL	Network Model	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
LOCATIONAL	CPIH	forecast			Actual
RESIDUAL / ADJUSTMENT	OFTO Revenue *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG best view
RESIDUAL / ADJUSTMENT	Allowed Revenue *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
RESIDUAL / ADJUSTMENT	Demand Charging Bases	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
RESIDUAL / ADJUSTMENT	Banding Data	Previous year's data source		DNO/IDNO consumption and site data updated	
RESIDUAL / ADJUSTMENT	Generation Charging Base	NG best view	NG best view	NG best view	NG final best view
RESIDUAL / ADJUSTMENT	Generation ALFs	Previous year's data source		New ALFs published	
RESIDUAL / ADJUSTMENT	Generation Revenue (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

Faraday House, Warwick Technology Park,
Gallows Hill, Warwick, CV346DA

nationalgrideso.com

nationalgridESO