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Forecast of TNUoS Tariffs for 2023/24

National Grid Electricity System Operator

August 2022

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Executive summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the August forecast of TNUoS Tariffs for 2023/24.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 2023/24 on our website[1].

This Forecast is for charging year 2023/24 and has no impact on 2022/23.

Regulatory Uncertainty – CMP317/327

SSE Judicial Review for TGR implementation was concluded on 11 April 2022, however Ofgem and SSE have both appealed. The appealing hearing took place in July 2022, the outcome of which was to schedule a follow-on hearing to understand how the legislation has changed over time due to the exit from Europe. Once this is concluded in September, we will have a further update.

Following the JR conclusion, CMP391[2] was raised and implemented, to fully align the CUSC methodology with Ofgem's interpretation of the Limiting Regulation. The changes were around the interpretation of charges associated with pre-existing assets when calculating the generation revenue (the "gen cap"). CMP392[3] was raised by SSE seeking further clarification in the CUSC about the Limiting Regulation.

In this report, we have included additional tables showing local tariffs associated with pre-existing assets.

Transmission Demand Residual (TDR)

TDR banded charges methodology will apply from charging year 2023/24 (as per Ofgem's decision on CMP343[4]) and has been included in our forecast of tariffs for 2023/24.

Total revenues to be recovered

The total TNUoS revenue is forecast at £4,080m for 23/24, an increase of £133.62m from the 5YV. This is due to inflation revisions of the TO MAR (+£165.94m), revisions to OFTO Allowed revenue inflation and forecast OFTO Asset Transfer Dates (+£15.96m), an Ofgem update regarding the Strategic innovation Fund (-£15.35m) and refreshed forecasts of Adjustment term (-£33.27m). The 2023/24 revenue forecast will be updated later this year and finalised by January Final Tariffs based on Onshore and Offshore TOs' submissions.

Generation tariffs

The total revenue to be recovered from generators is forecast at £919.1m for 2023/24, a decrease of £25.1m since the Initial tariffs. Mainly driven by the increase in in the error margin and exchange rate.

The generation charging base has been forecast to be 77.2GW based on our best view on generation projects for 2023/24. This is an increase of 2.3GW since the Initial tariffs. The average generation tariff is £11.91/kW, a decrease of £0.71/kW due to the decrease in generation revenue and increase in charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £3,161m for 2023/24, a £158.7m increase since the Initial tariffs. The main driver is the increase in revenue to be collected in total through TNUoS and a reduction in the proportion of revenue to be recovered from generation.

The impact on the end consumer is forecast to be £40.09 per household in 2023/24, an increase of

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

2 CMP391: Definition of 'Charges for Physical Assets Required for Connection' | National Grid ESO

3 CMP392: Transparency and legal certainty as to the calculation of TNUoS in conformance with the Limiting Regulation | National Grid ESO

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

£0.96 from Initial tariffs. This is due to the increase in the total demand revenue.

In 2023/24 it is forecast that £17.2m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £1.59m since the Initial tariffs. This is due to the increase in the forecast charging base for Embedded Export and an increase in the average locational tariffs. The average EET is forecast at £2.25/kW, which is an increase of £0.14/kW versus Initial tariffs.

The average gross HH demand tariff for 2023/24 is to be £5.28/kW, an increase of £0.51/kW and the average NHH demand tariff forecast is at 0.25p/kWh, an increase of 0.02p/kWh since Initial tariffs.

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts for 2023/24 is available on our website[5].

Our next TNUoS tariff publication will be the Draft 2023/24 tariffs in November 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 CUSC modifications raised from time to time.

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

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

Our contact details

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

Charging Methodology Changes

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This Report

This report contains the 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.

This section summarises any key changes to the methodology.

Charging methodology changes

In this forecast 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 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.

We have also implemented CMP391: Definition of 'Charges for Physical Assets Required for Connection' in this forecast. This modification was directed by Ofgem, following the Competition and Markets Authority (CMA)'s Order[6] on 20 May 2022 which had the practical effect of quashing the definition of "Charges for Physical Assets Required for Connection" from CUSC section 11. The implementation of CMP391 is forecast to shift the collection of £6.9m of revenue from demand to generation users (this did not change the overall shift of revenue collection from generation to demand users, which was mainly driven by updates on other parameters e.g. the error margin and the exchange rate). Locational tariffs (including wider and local tariffs) are not affected.

There are also a number of 'in-flight' proposals to change the charging methodologies. These are summarised in the CUSC modifications Table 23.

Regulatory Uncertainty

The SSE Judicial Review of the Competition and Markets Authority (CMA) decision in respect of Ofgem's approval of CMP317/327 concluded on 11 April 2022. However, Ofgem and SSE were granted leave to appeal (and cross appeal) the outcome. The appeal hearing took place in July 2022, the outcome of which was to schedule a follow-on hearing to understand how the legislation has changed over time, due to the exit from Europe. Once this concludes (which is expected to be in September), we will provide an update in our next forecast publication. In the meantime, we will continue setting tariffs as per the current CUSC methodology.

6 https://assets.publishing.service.gov.uk/media/6286586a8fa8f556203eb44d/Order_SSE_.pdf

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

In May 2022, Ofgem published their final decision[7], 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. Reform work on TNUoS charges is continuing separately, more information can be found on this below.

TNUoS Reform

In May 2022, Ofgem published an open letter[8] outlining their latest thinking on the scope of the work to be undertaken by a Task Force and asked National Grid Electricity System Operator to work with industry to establish membership. In the letter, Ofgem clarified that the Task Forces will look at improvements to today's methodology whilst keeping its core assumptions and modelling approach unchanged. They stated that this does not rule out significant changes to elements of TNUoS, for example, the transport model, changes to the 'backgrounds' against which charges are calculated, or the approach to the demand-weighted distributed reference node.

Any CUSC changes recommended by the Task Forces, will need to go through the usual CUSC modification process. Therefore, we don't expect any impact on the 2023/24 TNUoS tariffs.

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.

[7] https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-decision-and-direction
[8] https://www.ofgem.gov.uk/sites/default/files/2022-05/TNUoS%20Task%20Forces%20May%202022.pdf

Generation tariffs

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

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1. Generation tariffs summary

This section summarises our view of generation tariffs for 2023/24 and how these tariffs were calculated.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2023/24 Initial	2023/24 August	Change since last forecast
Adjustment	- 0.961037	- 1.548377	- 0.587340
Average Generation Tariff*	12.617166	11.909194	- 0.707972

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

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

The generation adjustment is used to ensure generation tariffs are compliant with Limiting Regulation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. The adjustment tariff is currently negative to ensure Generation Tariffs are compliant with the legislation. The implementation of CMP317/327, followed by the implementation of CMP391, means that charges for the "Connection Exclusion" (i.e. assets built for generation connection) are not included in the €2.50/MWh cap. In addition, in line with Ofgem's interpretation, charges on >100MW embedded generators are excluded from the €2.50/MWh cap too. TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Average generation tariffs have decreased by £0.71/kW, due to a decrease of £25.07m in the revenue to be collected from generation and the 2.29GW increase in the generation charging base compared to the initial forecast. The generation adjustment has decreased by £0.59/kW to become more negative. The decrease in revenue to be collected from generation is driven by increases in the Error Margin and Exchange rate since the initial forecast.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2023/24. 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. In previous forecasts we have used example ALFs as - Conventional Carbon 80%, Conventional Low Carbon 80% and Intermittent 40%. Prior to our August forecast, we reviewed the example ALFs we use for each fuel type to reflect the changing industry landscape and align to the ALFs we would expect to see based on the generic and specific ALFs we publish and use for charging. 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

Generation Tariffs						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	3.369407	22.656650	17.732147	-1.548377	17.976549	36.545665	26.379263
2	East Aberdeenshire	3.651755	12.605563	17.732147	-1.548377	14.238462	29.289697	21.856273
3	Western Highlands	3.679044	20.931808	17.228606	-1.548377	17.394833	35.058129	25.099543
4	Skye and Lochalsh	-1.256610	20.931808	18.915566	-1.548377	13.133963	31.809435	26.786503
5	Eastern Grampian and Tayside	4.983342	15.100567	14.633687	-1.548377	15.328667	29.394077	19.880565
6	Central Grampian	4.520357	15.709388	15.191172	-1.548377	15.332204	29.945193	20.712020
7	Argyll	2.682910	13.355210	21.288356	-1.548377	14.991959	32.439297	25.749824
8	The Trossachs	3.869140	13.355210	12.992269	-1.548377	12.859755	25.329440	17.453737
9	Stirlingshire and Fife	2.723684	12.451820	12.360038	-1.548377	11.100050	22.874210	16.414980
10	South West Scotlands	1.283336	12.550548	12.422921	-1.548377	9.724347	21.570791	16.522291
11	Lothian and Borders	3.561784	12.550548	7.426501	-1.548377	10.004227	18.852819	11.525871
12	Solway and Cheviot	1.575404	8.756436	7.145908	-1.548377	6.387965	13.740262	9.537927
13	North East England	3.933130	6.979119	4.537008	-1.548377	6.991204	12.156100	6.129235
14	North Lancashire and The Lakes	1.435233	6.979119	1.668092	-1.548377	3.345740	6.789287	3.260319
15	South Lancashire, Yorkshire and Humber	4.366391	3.489788	0.402864	-1.548377	4.375075	5.838219	0.424892
16	North Midlands and North Wales	3.116160	1.860025	-	-1.548377	2.311793	2.962802	-0.711366
17	South Lincolnshire and North Norfolk	1.662087	2.510249	-	-1.548377	1.117810	1.996397	-0.418765
18	Mid Wales and The Midlands	1.208774	2.283054	-	-1.548377	0.573619	1.372688	-0.521003
19	Anglesey and Snowdon	5.623138	1.487468	-	-1.548377	4.669748	5.190362	-0.879016
20	Pembrokeshire	8.631616	-6.658914	-	-1.548377	4.419673	2.089054	-4.544888
21	South Wales & Gloucester	4.240478	-7.104406	-	-1.548377	-0.149661	-2.636204	-4.745360
22	Cotswold	3.243473	3.061406	-8.630020	-1.548377	-0.532350	-4.638870	-8.800764
23	Central London	-5.338158	3.061406	-4.785303	-1.548377	-7.576094	-9.375784	-4.956047
24	Essex and Kent	-3.218539	3.061406	-	-1.548377	-3.542354	-2.470862	-0.170744
25	Oxfordshire, Surrey and Sussex	-0.334280	-2.338231	-	-1.548377	-2.817949	-3.636330	-2.600581
26	Somerset and Wessex	-2.070806	-4.002292	-	-1.548377	-5.220100	-6.620902	-3.349408
27	West Devon and Cornwall	-0.866747	-6.737239	-	-1.548377	-5.110020	-7.468053	-4.580135

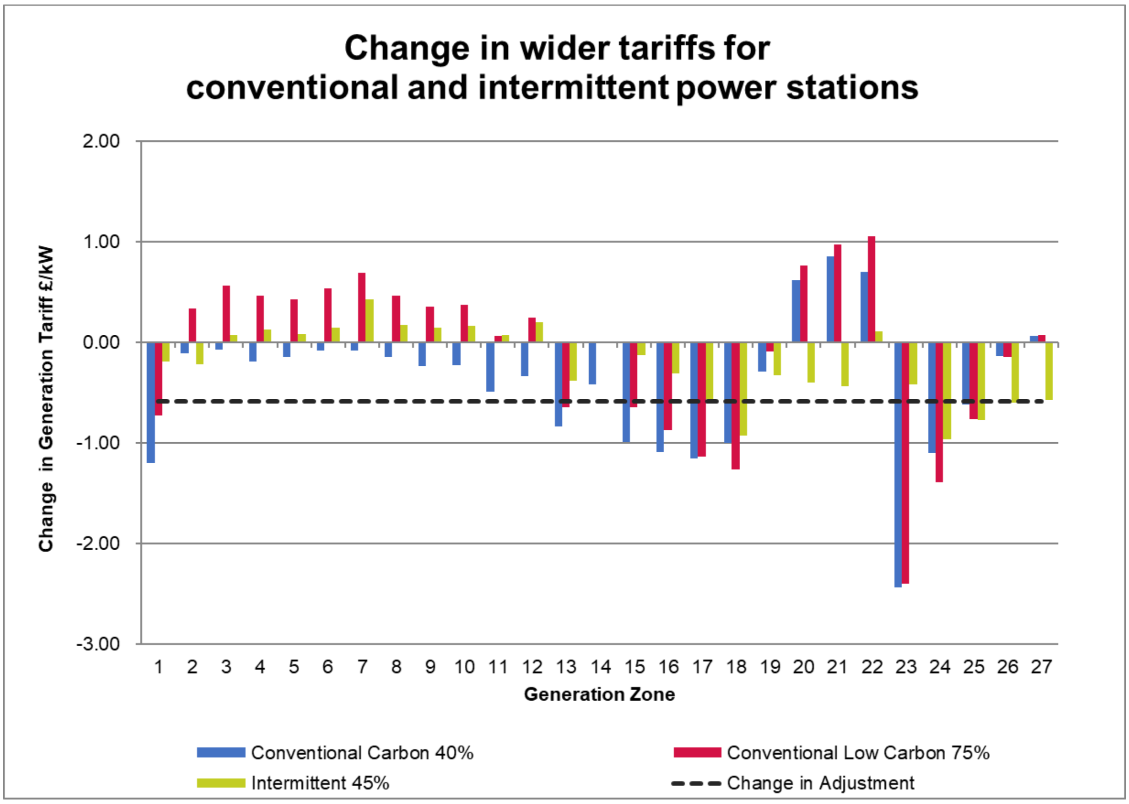
3. Changes to wider tariffs since the Initial Forecast

The following section provides details of the wider generation tariffs for 2023/24 and explains how these have changed since the initial forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only

Table 3 Generation wider tariff changes

Zone	Zone Name	Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			Change in Adjustment
		2023/24 Initial	2023/24 August	Change	2023/24 Initial	2023/24 August	Change	2023/24 Initial	2023/24 August	Change	
1	North Scotland	19.175871	17.976549	-1.199322	37.275505	36.545665	-0.729840	26.565164	26.379263	-0.185902	-0.587340
2	East Aberdeenshire	14.344799	14.238462	-0.106337	28.954191	29.289697	0.335506	22.077711	21.856273	-0.221437	-0.587340
3	Western Highlands	17.463669	17.394833	-0.068836	34.495870	35.058129	0.562259	25.025302	25.099543	0.074241	-0.587340
4	Skye and Lochalsh	13.327183	13.133963	-0.193220	31.341615	31.809435	0.467820	26.662354	26.786503	0.124149	-0.587340
5	Eastern Grampian and Tayside	15.470508	15.328667	-0.141842	28.962241	29.394077	0.431836	19.799922	19.880565	0.080644	-0.587340
6	Central Grampian	15.415821	15.332204	-0.083617	29.405238	29.945193	0.539955	20.564242	20.712020	0.147778	-0.587340
7	Argyll	15.071345	14.991959	-0.079385	31.750997	32.439297	0.688300	25.323997	25.749824	0.425827	-0.587340
8	The Trossachs	13.008284	12.859755	-0.148529	24.863395	25.329440	0.466045	17.283095	17.453737	0.170642	-0.587340
9	Stirlingshire and Fife	11.339578	11.100050	-0.239528	22.519949	22.874210	0.354261	16.264477	16.414980	0.150503	-0.587340
10	South West Scotlands	9.954927	9.724347	-0.230581	21.195930	21.570791	0.374862	16.355465	16.522291	0.166826	-0.587340
11	Lothian and Borders	10.490602	10.004227	-0.486376	18.791092	18.852819	0.061728	11.454610	11.525871	0.071261	-0.587340
12	Solway and Cheviot	6.727851	6.387965	-0.339887	13.493914	13.740262	0.246348	9.333043	9.537927	0.204885	-0.587340
13	North East England	7.828527	6.991204	-0.837323	12.797996	12.156100	-0.641896	6.507777	6.129235	-0.378542	-0.587340
14	North Lancashire and The Lakes	3.760922	3.345740	-0.415182	6.786805	6.789287	0.002482	3.268466	3.260319	-0.008147	-0.587340
15	South Lancashire, Yorkshire and Humber	5.363416	4.375075	-0.988342	6.480217	5.838219	-0.641998	0.553033	0.424892	-0.128142	-0.587340
16	North Midlands and North Wales	3.400624	2.311793	-1.088831	3.834891	2.962802	-0.872089	-0.402693	-0.711366	-0.308673	-0.587340
17	South Lincolnshire and North Norfolk	2.275950	1.117810	-1.158141	3.134337	1.996397	-1.137940	0.142603	-0.418765	-0.561368	-0.587340
18	Mid Wales and The Midlands	1.569610	0.573619	-0.995991	2.636043	1.372688	-1.263356	0.410091	-0.521003	-0.931094	-0.587340
19	Anglesey and Snowdon	4.959680	4.669748	-0.289932	5.279771	5.190362	-0.089409	-0.549492	-0.879016	-0.329525	-0.587340
20	Pembrokeshire	3.800128	4.419673	0.619545	1.321946	2.089054	0.767108	-4.147272	-4.544888	-0.397616	-0.587340
21	South Wales & Gloucester	-1.001457	-0.149661	0.851795	-3.605816	-2.636204	0.969613	-4.309499	-4.745360	-0.435861	-0.587340
22	Cotswold	-1.236394	-0.532350	0.704044	-5.694851	-4.638870	1.055981	-8.911051	-8.800764	0.110286	-0.587340
23	Central London	-5.135499	-7.576094	-2.440595	-6.973204	-9.375784	-2.402580	-4.543131	-4.956047	-0.412917	-0.587340
24	Essex and Kent	-2.440187	-3.542354	-1.102167	-1.077151	-2.470862	-1.393711	0.791439	-0.170744	-0.962183	-0.587340
25	Oxfordshire, Surrey and Sussex	-2.204566	-2.817949	-0.613383	-2.876014	-3.636330	-0.760317	-1.824326	-2.600581	-0.776255	-0.587340
26	Somerset and Wessex	-5.085560	-5.220100	-0.134540	-6.480005	-6.620902	-0.140897	-2.753895	-3.349408	-0.595514	-0.587340
27	West Devon and Cornwall	-5.171937	-5.110020	0.061918	-7.539289	-7.468053	0.071236	-4.004775	-4.580135	-0.575359	-0.587340

Figure 1 Variation in generation wider zonal tariffs



Locational changes

The locational tariffs have changed since the Initial tariffs, mainly due to revised view on the likely October contractual TEC (which will be used to set the locational elements in the final tariffs), and the increased expansion constant (EC).

This means that there have been changes in the overall tariffs across each generation zone. Using the example ALFs[9], Zone 23 (London) and a few zones surrounding it (Zones 24 – 25) have seen a decrease in tariffs for all technology types; for Zones 3 – 12, locational tariffs increased for Conventional low carbon and Intermittent. Overall, the North-South tariff divide is wider (with the exception of zones 19 – 22 which are affected more by the east – south flows).

Adjustment tariff changes

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

The adjustment tariff has decreased by £0.59/kW since the initial forecast, which means it has increased in magnitude due to it already being negative, this is mainly due to the increased error margin and exchange rate, which effectively reduce the revenue that can be recovered from generation. These changes cause the adjustment to go more negative as there is more adjustment required to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see Table 22.

[9] *The above examples can be misleading and are only to be used as a guide, as changes to ALFs can cause tariff variances to increase/decrease/reverses and the magnitude of this can fluctuate across zones and technology type.*

Onshore local tariffs for generation

4. Onshore local substation tariffs

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

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

Table 4 Local substation tariffs

2023/24 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.163360	0.081683	0.056341
<1320 MW	Redundancy	0.344217	0.174833	0.124142
>=1320 MW	No redundancy	-	0.239984	0.170862
>=1320 MW	Redundancy	-	0.361135	0.259744

5. Onshore local circuit tariffs

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

In this forecast, the 2023/24 onshore local circuit tariffs have been updated, and will be finalised by January. The updated tariffs are listed below in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberdeen Bay	2.894040	Dunhill	1.589817	Luichart	0.638343
Achruach	-2.833619	Dunlaw Extension	1.683898	Marchwood	0.424354
Aigas	0.742442	Edinbane	7.770855	Mark Hill	0.993931
An Suidhe	-1.060338	Enoch Hill	1.664511	Middle Muir	2.608444
Arecleoch	2.638271	Ewe Hill	1.688307	Middleton	0.168633
Beinneun Wind Farm	1.495879	Fallago	-0.072068	Millennium South	0.535601
Bhlaraidh Wind Farm	0.732934	Farr	3.957461	Millennium Wind	1.864109
Black Hill	1.723757	Fernoch	4.993299	Mossford	3.197685
Black Law	1.983594	Ffestiniogg	0.280818	Nant	-1.394528
BlackCraig Wind Farm	6.597618	Finlarig	0.363486	Necton	-0.701979
BlackLaw Extension	4.206468	Foyers	0.325126	Rhigos	0.117247
Clyde (North)	0.124492	Galawhistle	1.158927	Rocksavage	0.020048
Clyde (South)	0.143969	Glen Kyllachy	0.519266	Saltend	0.019259
Corriegarth	2.769416	Glendoe	2.088081	Sandy Knowe	3.579302
Corriemoillie	1.848472	Glenglass	5.263571	South Humber Bank	-0.206264
Coryton	0.052176	Gordonbush	-0.024365	Spalding	0.299218
CREAG RIABHACH	3.807947	Griffin Wind	10.767563	Strathbrora	-0.147778
Cruachan	2.025879	Hadyard Hill	3.142074	Strathy Wind	2.188440
Culligran	1.967488	Harestanes	2.653447	Stronelairg	1.207551
Cumberhead Collector	0.793352	Hartlepool	0.099899	Wester Dod	0.386276
Deanie	3.232302	Invergarry	0.415412	Whitelee	0.120476
Dersalloch	2.734448	Kilgallioch	1.194725	Whitelee Extension	0.334925
Dinorwig	2.663105	Kilmorack	0.224191		
Dorenell	2.329402	Kype Muir	1.683767		
Douglas North	0.778898	Langage	0.730473		
Dumnaglass	0.965719	Lochay	0.415412		

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

Table 6 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Bhlaraidh 132kV	Glenmoriston 132kV	7.4km Cable	7.4km OHL	Bhlaraidh
Enoch Hill 132kV	New Cumnock 132kV	4.4km Cable	4.4km OHL	Enoch Hill
Glen Glass 132kV	Sandy Knowe132kV	4km Cable	4km OHL	Sandy Knowe
Coalburn 132kV	Galawhistle 132kV	10.5km Cable	10.5km OHL	Galawhistle
Coalburn 132kV	Kype Muir 132kV	17km Cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km Cable	13km OHL	Middle Muir
Crystal Rig 132kV	Wester Dod 132kV	3.9km Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Melgarve 132kV	Stronelairg 132kV	10km Cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km Cable	15.33km OHL	Harestanes
Arecleoch 132kV	Arecleoch Tee 132kV	2.5km Cable	2.5km OHL	Arecleoch
Wishaw 132kV	Blacklaw 132kV	11.46km Cable	11.46km of OHL	Blacklaw

Offshore local 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. This forecast has been updated with the latest inflation indices. The change in tariffs since the initial forecast is slightly lower at Beatrice Windfarm (compared to other sites) due to the correction of an inflation error that was present in the initial forecast.

Offshore local generation tariffs associated with projects due to transfer in 2022/23 or 2023/24 will be confirmed once asset transfer has taken place.

Table 7 Offshore local tariffs 2023/24

Offshore Generator	2023/24 Initial Tariff Component (£/kW)			2023/24 August Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	9.809468	51.822915	1.286834	10.139060	53.564132	1.330071	0.329592	1.741217	0.043237
Beatrice	8.148209	22.397333	-	8.268518	22.670872	-	0.120309	0.273539	-
Burbo Bank	12.348075	23.865045	-	12.842889	24.821369	-	0.494814	0.956324	-
Dudgeon	18.061011	28.338003	-	18.784754	29.473568	-	0.723743	1.135565	-
Galloper	18.487887	29.240495	-	19.228736	30.412224	-	0.740849	1.171729	-
Greater Gabbard	18.277077	42.294994	-	18.891175	43.716078	-	0.614098	1.421084	-
Gunfleet	21.347488	19.686213	3.679466	22.064750	20.347658	3.803094	0.717262	0.661445	0.123628
Gwynt y mor	23.188182	22.925740	-	24.117382	23.844424	-	0.929200	0.918684	-
Hornsea 1A	8.253296	29.201452	-	8.584024	30.371617	-	0.330728	1.170165	-
Hornsea 1B	8.253296	29.201452	-	8.584024	30.371617	-	0.330728	1.170165	-
Hornsea 1C	8.253296	29.201452	-	8.584024	30.371617	-	0.330728	1.170165	-
Humber Gateway	13.646374	31.309478	-	14.193214	32.564116	-	0.546840	1.254638	-
Lincs	18.944427	74.501954	-	19.703571	77.487408	-	0.759144	2.985454	-
London Array	12.856093	44.078615	-	13.371264	45.844940	-	0.515171	1.766325	-
Ormonde	30.159856	56.375309	0.449264	31.173208	58.269483	0.464359	1.013352	1.894174	0.015095
Race Bank	10.937251	30.377770	-	11.375530	31.595073	-	0.438279	1.217303	-
Rampion	8.934681	23.372745	-	9.292713	24.309342	-			
Robin Rigg	- 0.661971	37.574824	12.038735	- 0.684212	38.837314	12.443228	- 0.022241	1.262490	0.404493
Robin Rigg West	- 0.661971	37.574824	12.038735	- 0.684212	38.837314	12.443228	- 0.022241	1.262490	0.404493
Sheringham Shoal	28.216888	33.232638	0.722380	29.164957	34.349233	0.746651	0.948069	1.116595	0.024271
Thanet	21.547139	40.368615	0.971815	22.271109	41.724974	1.004467	0.723970	1.356359	0.032652
Walney 1	26.049000	52.078574	-	26.924230	53.828381	-	0.875230	1.749807	-
Walney 2	24.234774	49.320180	-	25.049047	50.977306	-	0.814273	1.657126	-
Walney 3	11.234805	22.761042	-	11.685008	23.673126	-	0.450203	0.912084	-
Walney 4	11.234805	22.761042	-	11.685008	23.673126	-	0.450203	0.912084	-
West of Duddon Sands	10.047556	50.085752	-	10.450183	52.092796	-	0.402627	2.007044	-
Westermost Rough	20.430023	34.769302	-	21.248698	36.162582	-	0.818675	1.393280	-

Demand Tariffs

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

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, this includes the implementation of CMP343: 'Transmission Demand Residual bandings and allocation' which will take effect from 1st April 2023.

As per the Initial tariffs, the methodology for 2023/24 demand tariffs has incorporated CMP343. 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.

Table 8 Summary of demand tariffs

Non-locational Banded Tariffs	2023/24 Initial	2023/24 August	Change
Average (£/site/annum)	92.053240	97.687198	5.633958
Unmetered (p/kWh)	1.1095838	1.1660356	0.0564518
Demand Residual (£m)	2,925.6	3,074.4	148.8
HH Tariffs (Locational)	**2023/24 Initial**	**2023/24 August**	**Change**
Average Tariff (£/kW)	4.767689	5.281208	0.513519
Residual (£/kW)	-	-	-
EET	**2023/24 Initial**	**2023/24 August**	**Change**
Average Tariff (£/kW)	2.115591	2.252783	0.137192
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.464586	2.540292	0.075706
Embedded Export Volume (GW)	7.384554	7.643273	0.258720
Total Credit (£m)	15.622698	17.218637	1.595939
NHH Tariffs (locational)	**2023/24 Initial**	**2023/24 August**	**Change**
Average (p/kWh)	0.227167	0.250808	0.023641

From the publication of the Initial tariffs, average HH & NHH demand tariffs have increased, the main driver being the increase in the total amount of revenue to be recovered through TNUoS and the change in revenue to be recovered through generation tariffs, increasing the proportion of revenue to be recovered through demand tariffs. August tariffs for 2023/24 indicate that 77.5% of total revenue is to be recovered through demand, an increase of 0.9% since Initial tariffs, with overall demand revenue set at £3,016m (increase of £158.7m from Initial tariffs).

The average HH gross tariff is set at £5.28/kW, an increase of £0.51/kW compared to Initial tariffs. The average NHH tariff is forecast at 0.25p/kWh, an increase of 0.02p/kWh.

Overall, there has been a slight increase in forecasted Embedded Export Volume of 0.26GW to 7.64GW compared to the Initial tariff forecast. However, there has been a noticeable increase in the total credit paid out to embedded generators (<100MW), which is currently forecast at £17.22m, an increase of £1.59m. This is driven by an increase in export volumes for the Zones whose tariffs are not floored and a decrease in volumes for the Zones that are floored. The average EET is now forecast at £2.25/kW an increase of £0.14/kW compared to the Initial tariff forecast.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	0.812237
8	Midlands	-	-	2.505729
9	Eastern	0.933038	0.124251	3.473330
10	South Wales	2.493406	0.281869	5.033698
11	South East	3.520830	0.467587	6.061122
12	London	7.145918	0.741324	9.686210
13	Southern	5.712609	0.726061	8.252901
14	South Western	7.499372	1.027589	10.039664

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. Several mods relating to TDR banding methodology are currently under review, one of these (CMP389) has been raised to review the number of transmission connected bands and in particular the percentile thresholds used across those bands. We expect to have a view of the outcome of this mod for Draft tariffs.

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 10 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 10 Non-Locational demand residual banded charges

Band		2023/24 Initial	2023/24 August	Change
Domestic	Tariff - £/Site/Annum	36.81	38.68	1.87
LV_NoMIC_1		15.09	15.86	0.77
LV_NoMIC_2		85.35	89.70	4.34
LV_NoMIC_3		210.53	221.24	10.71
LV_NoMIC_4		665.22	699.06	33.84
LV1		1,061.49	1,115.50	54.01
LV2		1,993.89	2,095.33	101.44
LV3		3,239.31	3,404.11	164.80
LV4		7,358.82	7,733.21	374.39
HV1		4,909.20	5,158.96	249.76
HV2		17,778.41	18,682.91	904.50
HV3		34,737.54	36,504.86	1,767.33
HV4		89,495.74	94,048.97	4,553.23
EHV1		55,810.06	58,649.49	2,839.42
EHV2		216,161.23	227,158.76	10,997.53
EHV3		457,136.17	480,393.67	23,257.51
EHV4		1,182,280.46	1,242,430.80	60,150.34
T-Demand1		135,438.52	142,329.16	6,890.64
T-Demand2		484,704.19	509,364.26	24,660.07
T-Demand3		1,057,794.39	1,111,611.30	53,816.92
T-Demand4		3,097,790.30	3,255,395.15	157,604.85
Unmetered demand		**p/kWh**		
Unmetered		1.11	1.17	0.06
Demand Residual (£m)		**2,925.56**	**3,074.41**	**148.84**

The above tariffs are calculated based on the 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 current 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.

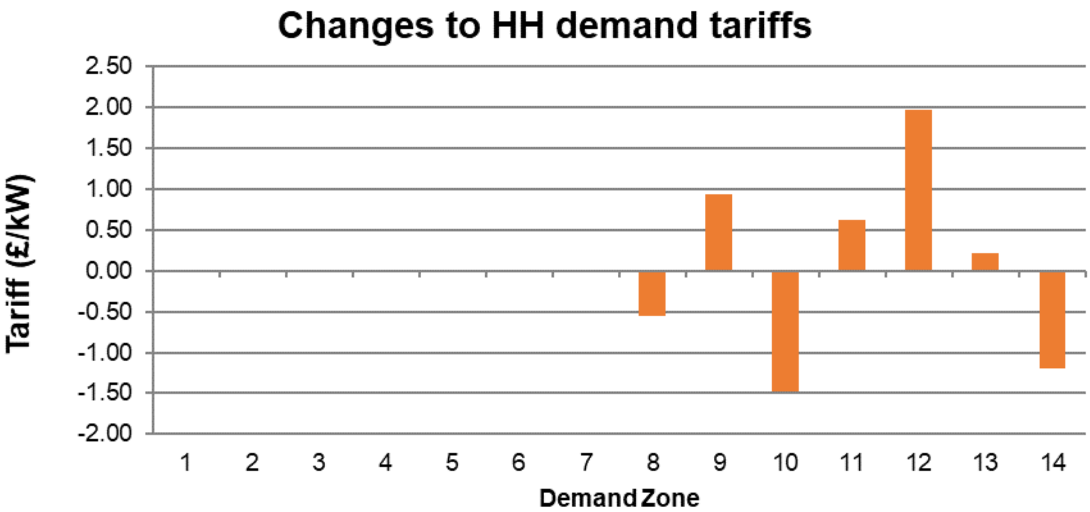
9. Half-Hourly demand tariffs

The table and figure below show the August gross HH demand tariffs for 2023/24 compared to the initial forecast.

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2023/24 Initial (£/kW)	2023/24 August (£/kW)	Change (£/kW)	Change in Residual (£/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	-	- 0.547267	-
9	Eastern	-	0.933038	0.933038	-
10	South Wales	3.972019	2.493406	- 1.478613	-
11	South East	2.905305	3.520830	0.615525	-
12	London	5.168789	7.145918	1.977129	-
13	Southern	5.504939	5.712609	0.207670	-
14	South Western	8.694899	7.499372	- 1.195527	-

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the fluctuations in tariffs for zones 7 through to 14 tariffs are due to a combination of an increase in the forecast Expansion Constant (EC) an increase of £0.5/MWkm since Initial tariffs due to the increase in forecast inflation and changes in the charging base (changes in forecast Gross and HH demand across zones) have also had an impact on locational tariffs which make up the HH tariff.

The forecast level of gross HH chargeable demand has increased slightly by 0.3GW in comparison with the Initial tariffs and is currently forecast at 19.75GW.

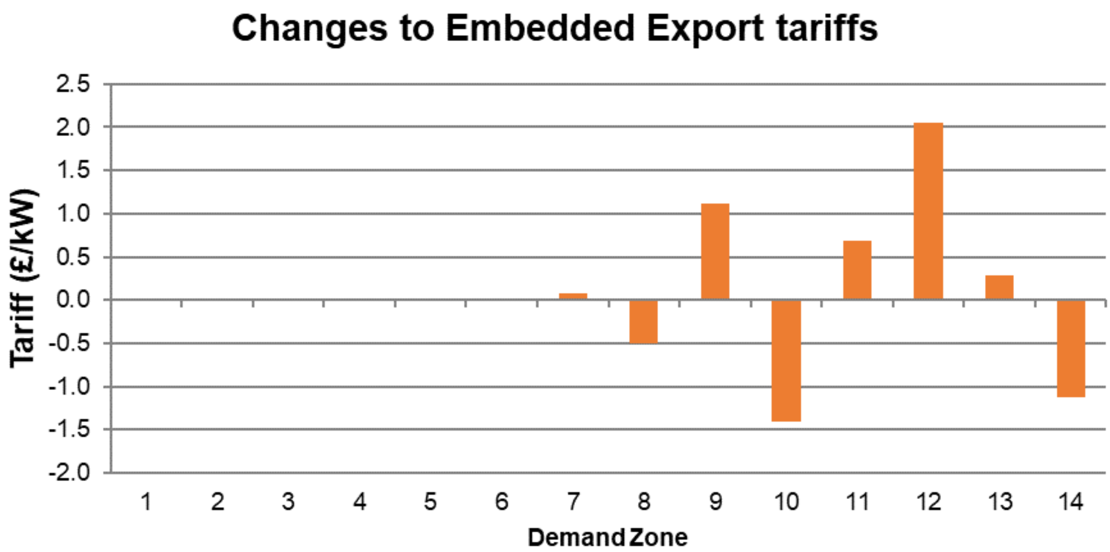
10. Embedded Export Tariffs (EET)

The next table and figure show the difference between the August tariffs forecast and Initial tariffs.

Table 12 Embedded Export Tariffs

Zone	Zone Name	2023/24 Initial (£/kW)	2023/24 August (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	0.729141	0.812237	0.083096
8	Midlands	3.011853	2.505729	- 0.506124
9	Eastern	2.354156	3.473330	1.119174
10	South Wales	6.436605	5.033698	- 1.402907
11	South East	5.369891	6.061122	0.691231
12	London	7.633375	9.686210	2.052835
13	Southern	7.969525	8.252901	0.283376
14	South Western	11.159485	10.039664	- 1.119821

Figure 3 Embedded export tariff changes



There have been further noticeable changes to the average EET in line with the changes in locational tariff elements as per the HH tariff narrative. The overall Embedded Export Volume has increased by 0.3GW to 7.64GW compared to Initial tariffs. There has been slight increase to the avoided GSP Infrastructure Costs (AGIC) tariff which increased from £2.46/kW to £2.54/kW for the August forecast. The overall impact of these changes has increased the average EET by £0.14/kW to £2.25/kW.

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.

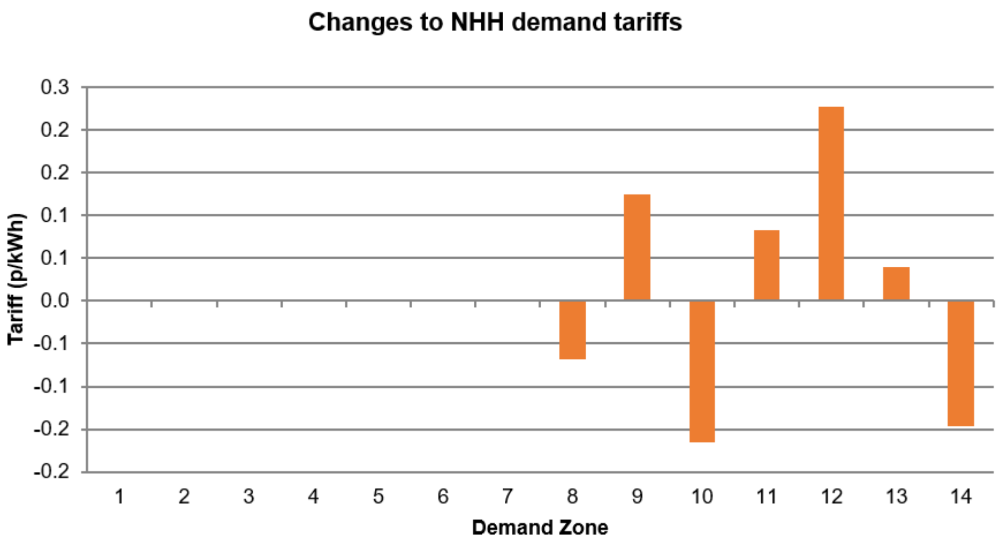
11. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2023/24 August and Initial tariffs.

Table 13 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2023/24 Initial (p/kWh)	2023/24 August (p/kWh)	Change (p/kWh)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	-	-	-
8	Midlands	0.067926	-	- 0.067926
9	Eastern	-	0.124251	0.124251
10	South Wales	0.447363	0.281869	- 0.165494
11	South East	0.385372	0.467587	0.082215
12	London	0.514028	0.741324	0.227296
13	Southern	0.686977	0.726061	0.039084
14	South Western	1.174085	1.027589	- 0.146496

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2023/24 Final tariffs is set at 0.25p/kWh, a 0.02p/kWh increase compared to Initial tariffs. As with the HH tariffs and the EET, the fluctuations to NHH tariffs since Initial tariffs has been the combination of an increase in the forecast of EC and changes to Demand Charging Bases, increase in the overall revenue to be recovered through Demand tariffs.

Overview of data inputs

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

12. Inputs affecting the locational element of tariffs

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

- Expected contracted generation (until October 2022 when it will be based on contracted TEC);
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, Modelled and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2023/24 period onwards, which can be found on the TEC register.[10] The contracted TEC volumes are based on the October 2021 TEC register.

Modelled Best View TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the initial and August forecasts, we have 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.

Table 14 Contracted, Modelled & Chargeable TEC

	2023/24 Tariffs			
Generation (GW)	Initial	August	Draft	Final
Contracted TEC	90.96	88.69		
Modelled Best View TEC	85.11	87.40		
Chargeable TEC	74.89	77.18		

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 25th July 2022.

[10] See the Registers, Reports and Updates section at https://www.nationalgrideso.com/connections/after-you-have-connected

Table 15 Interconnectors

Interconnector	Site	Interconnected System	Generation Zone	Generation MW Transport Model Peak	Generation MW Transport Model Year Round	Generation MW Charging Base
Britned	Grain 400kV	Netherlands	24	0	1,200	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
ElecLink	Sellindge 400kV	France	24	0	1,000	0
IFA Interconnector	Sellindge 400kV	France	24	0	2,000	0
IFA2 Interconnector	Chilling 400kV	France	26	0	1,100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	500	0
Nemo Link	Richborough 400kV	Belgium	24	0	1,020	0
NS Link	Blyth GSP	Norway	13	0	1,400	0
Viking Link	Bicker Fen 400kV	Denmark	17	0	1,500	0

14. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. The 2023/24 Expansion Constant is forecast to be £16.754009/MWkm using the latest forecast of inflation. With the approval of CMP353 the current EC value is based on the RIIO-T1 value set back 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). 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.

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 forecast, onshore substation tariffs are based on the values set for RIIO-2 and are inflated annually by CPIH.

17. Offshore local tariffs

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

For this forecast, offshore local tariffs are based on the values set for RIIO-2, inflated in line with the relevant OFTO's revenue.

18. Allowed revenues

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

For onshore TOs, the allowed revenues are subject to Ofgem's price control (RIIO-T2 period spans across 2021/22 – 2025/25), and parameters including project spending profiles, rate of return and inflation index are set at the beginning of each price control period. Onshore TOs' allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process (AIP).

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

The TOs will provide the ESO with their revenue forecast under the agreed timeline as specified in the STC (SO-TO Code). The 2023/24 revenue forecast will be updated later this year and finalised by January Final Tariffs based on Onshore and Offshore TOs' submissions.

Table 16 Allowed revenues

	2023/24 TNUoS Revenue			
£m Nominal	Initial Forecast	August Forecast	November Draft	January Final
TO Income from TNUoS				
National Grid Electricity Transmission	1,991.6	2,097.3	-	-
Scottish Power Transmission	421.2	443.6	-	-
SHE Transmission	712.4	750.2	-	-
Total TO Income from TNUoS	**3,125.2**	**3,291.1**	**-**	**-**
Other Income from TNUoS				
Other Pass-through from TNUoS	87.0	38.3	-	-
Offshore (plus interconnector contribution / allowance)	735.2	751.2	-	-
Total Other Income from TNUoS	**822.2**	**789.5**	**-**	**-**
Total to Collect from TNUoS	**3,947.3**	**4,080.6**	**-**	**-**

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

The G/D split forecast is shown in Table 17.

In this forecast, we have incorporated CMP391 which is the definition of Connection Exclusion. The Connection Exclusion is given effect in the CUSC by the defined term, "Charges for Physical Assets Required for Connection". Majority of TNUoS local charges (including onshore and offshore local charges) still fall into the definition of Connection Exclusion, however, a small part of the TNUoS onshore local charges (about £2.4m in this forecast) are categorised as charges associated with pre-existing assets and are therefore not Connection Exclusion.

We also made a charge with regards to charges on embedded generators with >100MW capacity. According to Ofgem's interpretation of the Limiting Regulation, these charges (totally around £9.3m in this forecast) are not included when calculating the gen cap. The net effect of the above changes (Connection Exclusion, and TNUoS-liable embedded generation) has shifted around £6.9m of charge from demand to generation. This shift has slightly offset the decreased generation revenue compared to the Initial forecast, which was due to updates on charging parameters including the error margin, the forecast generation TWh figure and the Euro/Sterling exchange rate.

Table 17 Generation and demand revenue proportions

Code	Revenue	2023/24 Tariffs Initial Forecast	August Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5		
y	Error Margin	14.2%	23.6%		
ER	Exchange Rate (€/£)	1.17	1.19		
MAR	Total Revenue (£m)	3,947.0	4,080.6		
GO	Generation Output (TWh)	194.9	199.8		
G	% of revenue from generation	23.92%	22.52%		
D	% of revenue from demand	76.08%	77.48%		
G.R	Revenue recovered from generation (£m)	944.2	919.1		
D.R	Revenue recovered from demand (£m)	3,002.8	3,161.5		
Breakdown of generation revenue					
	Revenue from the Peak element	129.3	115.1		
	Revenue from the Year Round Shared element	124.3	149.5		
	Revenue from the Year Round Not Shared element	176.2	174.5		
	Revenue from Onshore Local Circuit tariffs	17.1	17.3		
	Revenue from Onshore Local Substation tariffs	10.7	11.0		
	Revenue from Offshore Local tariffs	558.6	571.1		
	Revenue from the adjustment element	-71.9	-119.5		
G.MAR	Total Revenue recovered from generation (£m)	944.2	919.1		
	Including revenue from large embedded generation (£m)	*	9.3		
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	*	2.4		

*No applicable for forecast

The “gen cap”

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges 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 was referred to as the “gen cap” which is art of the UK law. 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 included in the 2021/22 final tariffs. When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod, 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). Since this year, and following CMA’s Order[11] on 20 May 2022, CMP391 was raised and approved. After incorporating the follow-up changes post CMP317/327, the generation and demand revenue (the G/D split) was shifted by a few million pounds (£6.9m in this forecast). Locational tariffs (including wider locational land local tariffs) are not affected.

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 published prior to 31st October. In this forecast, the exchange rate is based on OBR’s March EFO, and the figure has been updated since the Initial tariffs. The latest figure is €1.193850/£.

[11] https://assets.publishing.service.gov.uk/media/6286586a8fa8f556203eb44d/Order_SSE_.pdf

Generation Output

The forecast output of generation is 199.79TWh. This figure is the average of the four scenarios (plus the central case) in the 2022 Future Energy Scenarios and the value to be used to set tariffs for 2023/24

Error Margin

The error margin has been recalculated in this forecast, following publication of the 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 use data from years 2017/18 – 2021/22).

Table 18 Generation revenue error margin calculation

Calculation for	2023/24		
	Revenue inputs		Generation output variance
Data from year:	Revenue variance	Adjusted variance	
2017/18	-5.2%	2.4%	-1.5%
2018/19	-9.2%	-1.6%	-7.5%
2019/20	-14.6%	-7.1%	-4.1%
2020/21	-13.2%	-5.6%	7.5%
2021/22	4.3%	11.9%	9.5%
Systemic error:	-7.6%		
Adjusted error:		11.9%	9.5%
Error margin =			23.6%

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

Onshore local charges associated with Pre-existing assets

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

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

Table 19 lists out the onshore local circuit tariffs associated with pre-existing assets. Individual users who pay onshore local circuit tariffs are not affected by CMP391, as the tariffs in Table 19 are only used for the purpose of calculating the gen cap.

Table 19 Onshore local circuit tariffs associated with pre-existing assets

Project Name	Pre-existing local circuit tariff (£/kW)	Aggregated pre-existing TEC (MW)
Aigas (part of the Beauly Cascade)	0.742442	6332
Aikengall IIa Wind Farm	0.386276	
An Suidhe Wind Farm - Argyll (SRO)	- 1.061359	
Blackcraig Wind Farm	6.597618	
Corriemoillie Wind Farm	1.848507	
Culligran (part of the Beauly Cascade)	1.967488	
Cumberhead	0.793352	
Dalquhandy Wind Farm	0.793352	
Deanie (part of the Beauly Cascade)	3.232302	
Edinbane Windfarm	7.770840	
Farr Wind Farm - Tomatin	3.957461	
Ffestiniog	0.280818	
Finlarig	0.363486	
Foyers	0.325126	
Glendoe	2.088081	
Hirwaun Power Station	0.117126	
Invergarry (part of the Garry Cascade)	0.415412	
Keith Hill Wind Farm	1.683753	
Kilbraur Wind Farm	0.931790	
Kilgallioch	1.194725	
Luichart (part of the Conon Cascade)	0.638378	
Mark Hill Wind Farm	0.993931	
Millennium South	0.535601	
Mossford (part of the Conon Cascade)	3.197720	
Nant	- 1.394517	
Rocksavage	0.020047	
Saltend	0.019259	
South Humber Bank	- 0.206299	
Spalding	0.297933	
Strathy North Wind	2.200725	
Tralorg Wind Farm	0.993931	

Onshore local substation tariff reflects the cost of accommodating the generator to its local substation. It is very rare for generators to have local substation tariff associated with pre-existing assets, as usually each generator has its own dedicated bay. Table 20 lists out the onshore local substation tariffs associated with pre-existing assets.

Table 20 Onshore local substation tariffs associated with pre-existing assets

Project Name	Pre-existing substation Tariff (£/kW)	Aggregated pre-existing TEC (MW)
Pogbie Wind Farm	0.344217	41.7
Toddleburn Wind Farm	0.344217	
Keith Hill Wind Farm	-	

20. Charging bases for 2023/24

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 tariffs is forecast at 77.2GW, which is an increase of 2.3GW since the initial forecast. It is based on our internal view of what generation we expect to connect next financial year.

For the Final Tariffs, in line with the CUSC, we will use the contracted TEC position as of 31st October 2022 to set locational tariffs in the Transport model; our best view is used to set the adjustment tariff in the Tariff model.

Demand

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

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 (January 2019 -July 2022)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

We assume that with recent historical trends and forward-looking assumptions (excluding the impact of COVID-19) demand volumes will stay relatively consistent over the next few years. 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 in future years. The impact of COVID-19 continues to be tracked and adjustments have been made in our forecast since Initial forecast for 2023/24 based on the latest demand outturn data up to end of July 2022. Please refer to table TAA in the published tables spreadsheet for a detailed breakdown of the changes to the demand changing bases.

Table 21 Charging bases

	2023/24 Tariffs			
Charging Bases	Initial	August	Draft	Final
Generation (GW)	74.89	77.18		
NHH Demand (4pm-7pm TWh)	24.54	24.86		
Gross charging				
Total Average Gross Triad (GW)	49.72	50.67		
HH Demand Average Gross Triad (GW)	19.48	19.75		
Embedded Generation Export (GW)	7.38	7.64		

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.[12]

22. Generation adjustment and demand residual

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

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

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

Where:

A_G is the adjustment tariff (£/kW)

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

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

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

B_G is the generator charging base (GW)

A_G cannot be positive and is capped at 0.

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 p/site/day (sometimes referenced as £/site/annum) 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 demand locational tariffs.

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

Table 22 Residual & Adjustment components calculation

	Component	2023/24 Tariffs Initial	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	23.92%	22.52%		
D	Proportion of revenue recovered from demand (%)	76.08%	77.48%		
R	Total TNUoS revenue (£m)	3,947.0	4,080.6		
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	429.8	439.1		
O	Revenue recovered from offshore local tariffs (£m)	558.6	571.1		
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.7	11.0		
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.1	17.3		
	Revenue from large embedded generation (£m)	*	9.3		
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	*	2.4		
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5		
	Error Margin	14.2%	23.6%		
	Exchange Rate (€/£)	1.17	1.19		
	Total generation Output (TWh)	194.9	199.8		
	Generation Output from TNUoS chargeable EGs (TWh)	*	*		
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	357.9	319.4		
	Adjustment Revenue (£m)	-71.9	-119.7		
BG	Generator charging base (GW)	74.9	77.2		
AdjTariff	Generator adjusment tariff (£/kW)	-0.96	-1.55		
Gross demand residual					
R_D	Demand residual (£m)	2,925.6	3,074.4		
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	92.9	104.3		
EE	Amount to be paid to Embedded Export Tariffs (£m)	15.6	17.2		
B_D	Demand Gross charging base (GW)	49.7	50.6		

*Not applicable for this forecast

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 August Quarterly Forecast on Thursday 15th September. 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/266476/download

This data can also be accessed via our Data Portal:

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

Please allow up to two weeks after the publication for the data portal to be updated.

Contact Us

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

Appendix A: Background to TNUoS charging

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.

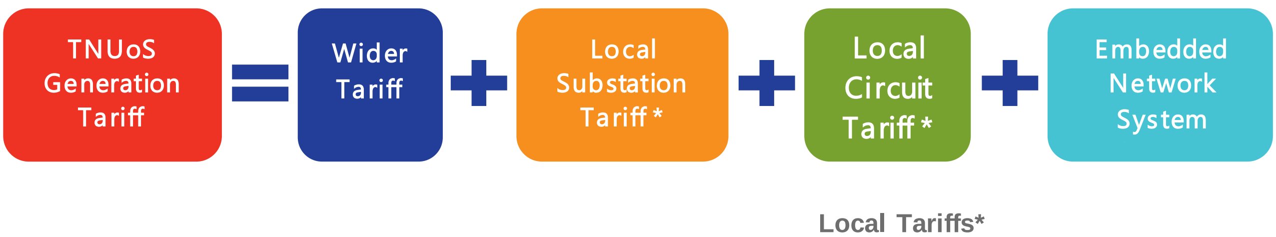
Generation charging principles

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.

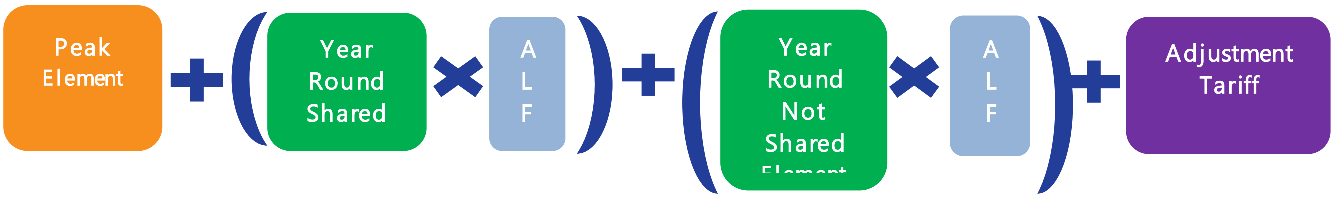
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

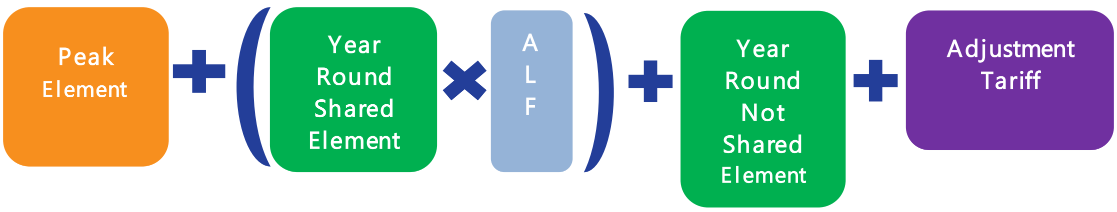
Conventional Carbon Generators

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



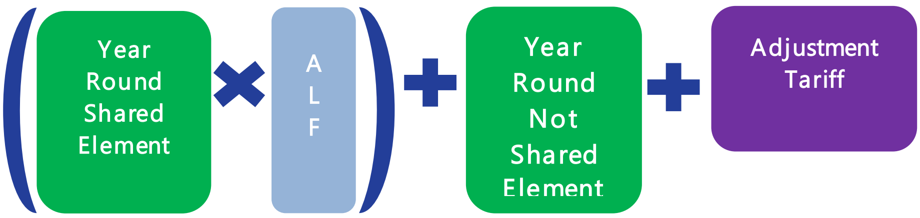
Conventional Low Carbon Generators

(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[13] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[14] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Click here to find out more about DNO regions.

Offshore local tariffs

Where an offshore generator's 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.

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.

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

[14] Distribution network Use of System charges

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.[15] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data 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[16], 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[17].

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.

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.

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15 https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data
16 https://www.nationalgrideso.com/document/130641/download
17 https://www.nationalgrideso.com/charging/charging-guidance

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

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

Appendix B: Changes and proposed changes to the charging methodology

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Proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariffs for financial year 2023/24. All these modifications are subject to whether they are approved by Ofgem, and which Work Group Alternative CUSC Modification (WACM) is approved (if applicable).

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 potentially affect 2023/24 TNUoS tariffs and their status, are listed below.

Table 23 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP315/375	Expansion Constant & Expansion Factors review	Affect TNUoS locational tariffs for generators and demand users	Potential implementation dates will be included once the relevant modification has reached a sufficient stage of development.
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.	
CMP379	Determining TNUoS demand zones for transmission - connected demand at sites with multiple Distribution Network Operators (DNOs)	Clarify 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 manifestest error thresholds	
CMP389	Transmission Demand Residual (TDR) band boundaries updates	Determine banding criteria for transmission connected users	

Please note that 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. 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

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Locational components of demand tariffs

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

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

Table 24 Location elements of the HH demand tariff for 2023/24

Demand Zone		2023/24 Initial		2023/24 August		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.600906	-29.132269	-2.035381	-30.818022	0.565525	-1.685754
2	Southern Scotland	-2.795621	-20.364090	-2.439368	-22.069355	0.356253	-1.705264
3	Northern	-4.079732	-8.925711	-3.544673	-10.225715	0.535059	-1.300003
4	North West	-1.250935	-4.689908	-1.127355	-5.593885	0.123580	-0.903977
5	Yorkshire	-2.961623	-2.741055	-2.496096	-3.854227	0.465527	-1.113172
6	N Wales & Mersey	-2.100891	-1.944674	-2.018190	-2.605353	0.082701	-0.660679
7	East Midlands	-2.676694	0.941249	-2.495909	0.767854	0.180785	-0.173395
8	Midlands	-1.551307	2.098574	-1.754297	1.719734	-0.202990	-0.378840
9	Eastern	0.903026	-1.013456	1.002243	-0.069206	0.099217	0.944250
10	South Wales	-3.566135	7.538154	-4.581861	7.075267	-1.015726	-0.462887
11	South East	3.261132	-0.355827	3.177970	0.342860	-0.083162	0.698688
12	London	5.023047	0.145743	5.429676	1.716242	0.406629	1.570499
13	Southern	1.708529	3.796411	1.463798	4.248810	-0.244731	0.452400
14	South Western	1.585107	7.109792	0.691449	6.807923	-0.893658	-0.301869

Table 25 Elements of the Embedded Export Tariff for 2023/24

Demand Zone		2023/24 Initial		2023/24 August		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-31.733175	2.464586	-32.853403	2.540292	-1.120228	0.075706
2	Southern Scotland	-23.159711	2.464586	-24.508722	2.540292	-1.349012	0.075706
3	Northern	-13.005443	2.464586	-13.770387	2.540292	-0.764944	0.075706
4	North West	-5.940843	2.464586	-6.721240	2.540292	-0.780396	0.075706
5	Yorkshire	-5.702678	2.464586	-6.350323	2.540292	-0.647645	0.075706
6	N Wales & Mersey	-4.045565	2.464586	-4.623543	2.540292	-0.577977	0.075706
7	East Midlands	-1.735445	2.464586	-1.728055	2.540292	0.007390	0.075706
8	Midlands	0.547267	2.464586	-0.034563	2.540292	-0.581830	0.075706
9	Eastern	-0.110430	2.464586	0.933038	2.540292	1.043467	0.075706
10	South Wales	3.972019	2.464586	2.493406	2.540292	-1.478613	0.075706
11	South East	2.905305	2.464586	3.520830	2.540292	0.615526	0.075706
12	London	5.168789	2.464586	7.145918	2.540292	1.977128	0.075706
13	Southern	5.504939	2.464586	5.712609	2.540292	0.207669	0.075706
14	South Western	8.694899	2.464586	7.499372	2.540292	-1.195527	0.075706

Appendix D: Annual Load Factors

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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 26 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 14.15.111.

Appendix E: Contracted generation

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

The contracted generation used in the Transport model will be fixed using the TEC register as of 31 October 2022, as stated by the CUSC 14.15.6 and no further changes to Contracted TEC will be made.

Table 27 shows the contracted generation changes notified since the initial forecast using data from the July 2022 TEC register. Please note that stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

Table 27 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Arecleoch Windfarm Extension	-73	AREX10	10
Bolney (tertiary)	-57	BOLN40	25
Burwell 1 Solar Limited	50	BURW40	18
Bustleholme	49.9	BUST20	18
Capenhurst 275KV Substation	100	CAPE20	16
Dalquhandy Wind Farm	-3	CCSS10	11
Firth of Forth Phase 1	260	TEAL20	5
JG Pears	20	HIGM40	16
Llanwern Phase 2	-190	WHSO20	21
Lovedean (Tertiary)	-57	LOVE40	25
Norwich	50	NORM40	18
Plas Power Estate North Tertiary	-57	LEGA40	18
Priestgill Wind Farm	-41	ELVA40	11
Sandy Knowe Wind Farm	47.4	SAKN10	10
Sofia Offshore Wind Farm	-1320	LACK40	13
Upware Solar Farm	-49.99	BURW40	18
Walpole 2 (tertiary)	-57	WALP40_EME	17
Warley (tertiary)	-7.1	WARL20	18
West Burton A	-900	WBUR40	16
Whitelaw Brae Windfarm	-57	CLYS2R	11
Whitelee Extension	32	WLEX20	10
Windy Standard II (Brockloch Rig) Wind Farm	-13.5	DUNH1R	10

Appendix F: Transmission company revenues

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Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have not updated us with their revenue forecast for year 2023/24. We do not anticipate an update until late October. Therefore, the current update includes using Onshore and offshore revenue figures from the Initial forecast. The notable difference in this forecast is the inclusion of updated CPIH figures. In addition, there are changes to some pass-through items that are to be collected by NGESO via TNUoS charges. These include strategic innovation fund (SIFt) a reduction of £15.35m from the Initial forecast. The Adjustment term (ADJt) a reduction of £33.27m from Initial forecast.

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.

Interconnector Early Payment

According to this weblink [18], Ofgem has approved National Grid Venture (NGV)’s offer to make early payments to consumers of £200 million over the next two years, as part of the cap and floor regulatory regime for electricity interconnectors. The approval from Ofgem, enables Interconnectors under cap & floor arrangements, to make payments of above cap revenues significantly earlier than originally planned, which will offset TNUoS revenue and thus contribute to reducing consumer energy costs over the next two years. NGV have submitted the proposed payments figures (for Financial Year 2023/24) to Ofgem and will confirm the figures to the ESO in accordance with the procedure as set out in CUSC section 9, and will be included in November Draft tariffs forecast.

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.

Since our Initial forecast, it can be observed that there is a reduction of -£48.62m pass-through revenue. This aggregate reduction is made of a few variables which have changed (see table 25) with the most notable variations being seen with a reduction in Strategic Innovation Fund value of (-£15.35m in comparison to the last update for forecast provided by UKRI in March 2022), the Adjustment Factor (-£33.27m as actuals replaces forecast data),

[18] https://www.nationalgrid.com/ofgem-enables-national-grid-make-early-payment-interconnector-revenues-helping-reduce-household

Table 28 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through		
	Initial Forecast	August Forecast	Variance
Embedded Offshore Pass-Through (OFETt)	0.70	0.70	0.00
Network Innovation Competition Fund (NICFt)	12.85	12.85	0.00
Strategic Innovation Fund (SIFt)	25.25	9.90	-15.35
The Adjustment Term (ADJt)	4.24	-29.02	-33.27
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	735.19	751.15	15.96
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.00
Termination Sums (TSt)	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	1,991.59	2,097.34	105.75
SPT revenue pass-through (TSPt)	421.23	443.60	22.37
SHETL revenue pass-through (TSHt)	712.36	750.18	37.82
ESO Bad debt (BDt)	3.60	3.60	0.00
ESO other pass-through items (LFt + ITCt etc)	40.33	40.33	0.00
ESO legacy adjustment (LARt)	0.00	0.00	0.00
Total	**3,947.34**	**4,080.62**	**133.27**

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 not provided us with their forecasted revenue breakdown for 2023/24. We have therefore used the previous actual revenue forecast submission and applied the latest CPIH for this forecast.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2023/24 is forecast to be £751.15m, an increase of £15.96m from the Initial forecast. Revenues have been adjusted using updated using latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

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

Table 29 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	324.73	341.97		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,737.57	1,737.57		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**1,991.59**	**2,097.34**		
SONIA	B1	It-1	1.15%	1.15%		
Allowed Revenue	B2	ARt-1	1,795.07	1,795.07		
Recovered Revenue	B4	RRt-1	1,795.07	1,795.07		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	0.00	0.00		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**0.00**	**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**1,991.59**	**2,097.34**		

Table 30 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission			
			Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	324.73	341.97		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	367.50	367.50		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**421.23**	**443.60**		
SONIA	B1	It-1	1.15%	1.15%		
Allowed Revenue	B2	ARt-1	0.00	0.00		
Recovered Revenue	B4	RRt-1	0.00	0.00		
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	0.00	0.00		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00		
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**0.00**	**0.00**		
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**421.23**	**443.60**		

Table 31 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission Initial Forecast	August Forecast	November Draft	January Final
Inflation 2018/19		$PI_{2018/19}$	283.31	283.31		
Inflation		PI_t	324.73	341.97		
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	621.50	621.50		
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00		
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**712.36**	**750.18**		
SONIA	B1	It-1	1.15%	1.15%		
Allowed Revenue	B2	ARt-1	673.24	673.24		
Recovered Revenue	B4	RRt-1	673.24	673.24		
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**		
Legacy pass-through	C1	LPt	0.00	0.00		
Legacy MOD	C2	LMODt	0.00	0.00		
Legacy K correction	C3	LKt	0.00	0.00		
Legacy TRU term	C4	LTRUt	0.00	0.00		
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00		
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00		
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00		
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00		
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00		
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**0.00**	**0.00**		
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**712.36**	**750.18**		

Table 32 Offshore revenues

Offshore Transmission Revenue Forecast (£m) Regulatory Year	Year 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.7	7.0	7.7	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	8.7	9.6	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	15.6	17.4	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	9.8	10.8	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	16.3	18.1	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	24.2	26.5	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	14.7	16.2	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	33.2	36.7	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	46.8	51.4	Current revenues plus indexation
Thanet	78.9	17.4	15.7	19.5	18.6	19.2	19.7	20.8	21.6	23.8	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	32.5	35.4	Current revenues plus indexation
Gwynt y mor		25.3	23.6	29.3	32.7	34.0	18.9	32.9	39.8	34.6	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	25.5	28.0	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	13.3	14.9	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	14.7	16.3	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	14.7	16.3	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	20.8	23.1	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	28.9	32.0	Current revenues plus indexation
Galloper							16.1	17.1	17.8	19.7	Current revenues plus indexation
Walney 3							28.8	13.5	14.1	15.6	Current revenues plus indexation
Walney 4								13.5	14.1	15.6	Current revenues plus indexation
Hornsea 1A								137.1	18.4	20.4	Current revenues plus indexation
Hornsea 1B									18.4	20.4	Current revenues plus indexation
Hornsea 1C									18.4	20.4	Current revenues plus indexation
Beatrice									21.1	24.1	Current revenues plus indexation
Rampion									15.5	17.9	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2022/23									68.3	143.1	National Grid Forecast
Forecast to asset transfer to OFTO in 2023/24										19.3	National Grid Forecast
Offshore Transmission Pass-Through (B7)	218.4	247.3	260.8	265.5	318.0	390.6	387.0	549.0	594.3	735.3	

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. It is possible that anticipated asset transfer dates moved between charging years in which case where a previous year shows a forecast for multiple sites, other sites may also have been included in addition to the ones shown.

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

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

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

Appendix G: Generation zones map

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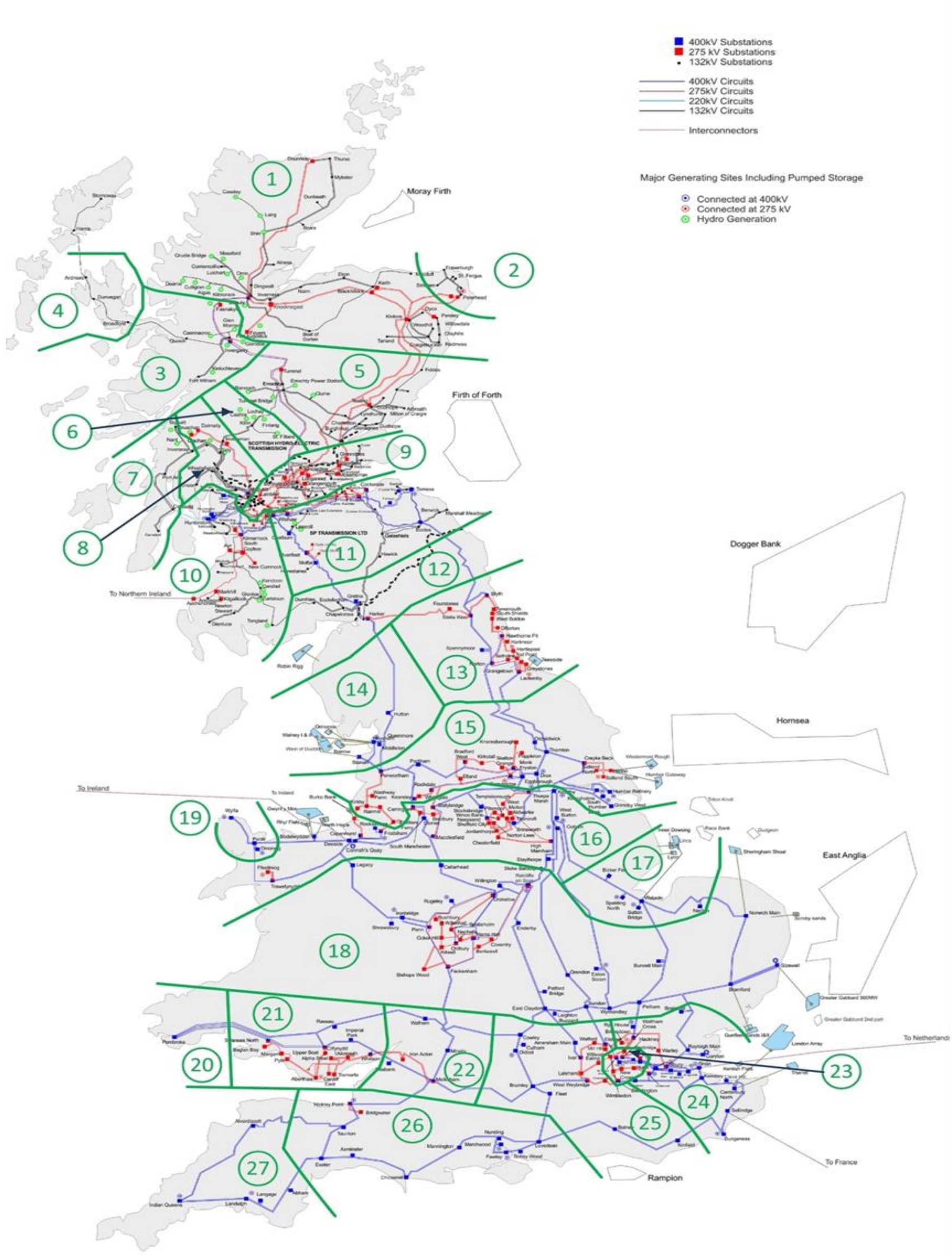
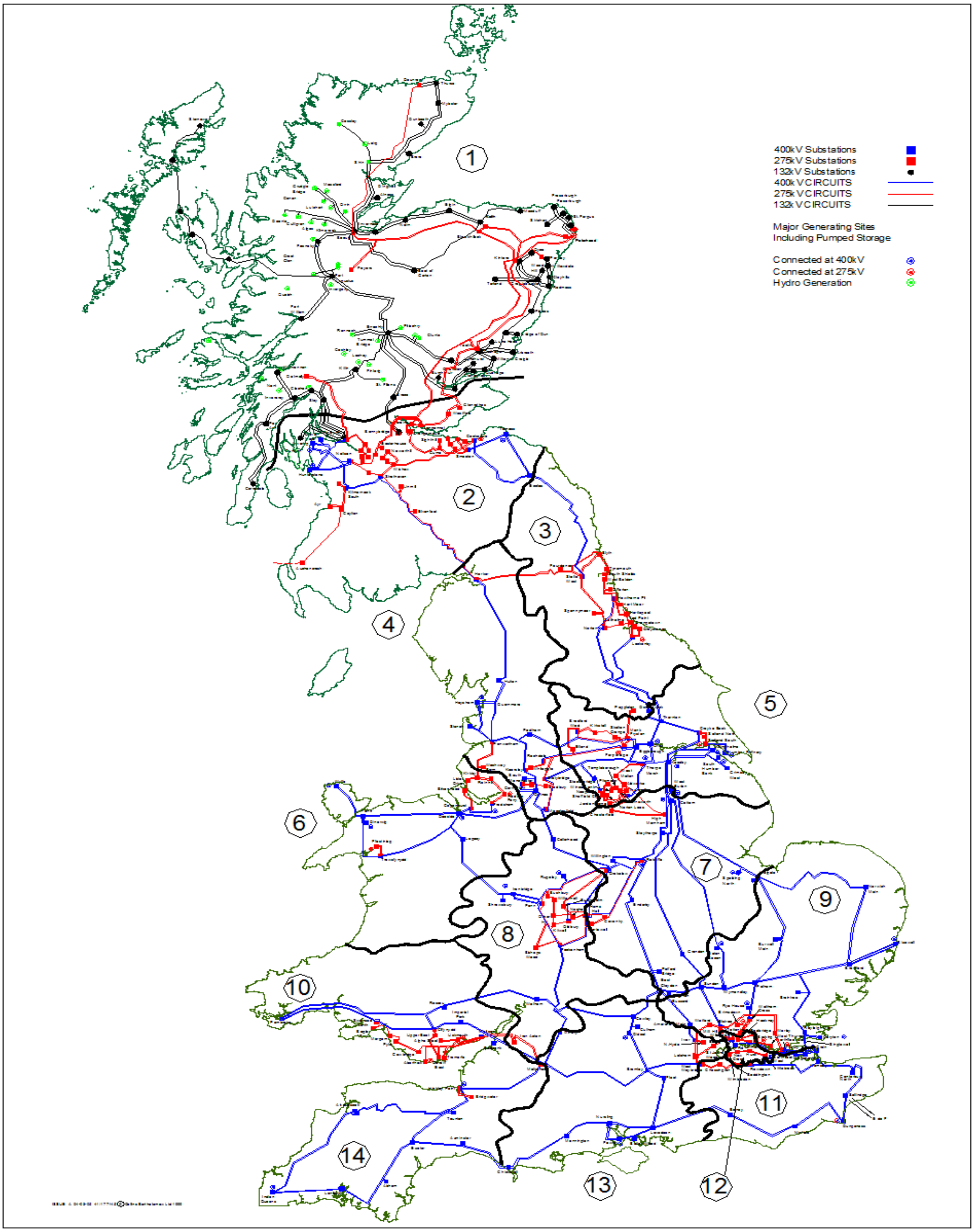
Figure A2: GB Existing Transmission System



Appendix H: Demand zones map

national grid ESO


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

Appendix I: Changes to TNUoS parameters

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The following table summarises the various inputs to the tariff calculations, indicating which updates are provided in each forecast during the year. Purple highlighting indicates that parameters are fixed from that forecast onwards.

<table>
<tr><th colspan="6">2023/24 TNUoS Tariff Forecast</th></tr>
<tr><th colspan="2"></th><th>April 2022</th><th>August 2022</th><th>Draft Tariffs November 2022</th><th>Final Tariffs January 2023</th></tr>
<tr><td colspan="2">Methodology</td><td colspan="4">Open to industry governance</td></tr>
<tr><td rowspan="4">LOCATIONAL</td><td>DNO/DCC Demand Data</td><td colspan="2">Initial update using previous year’s data source</td><td>Week 24 updated</td><td></td></tr>
<tr><td>Contracted TEC</td><td>Latest TEC Register</td><td>Latest TEC Register</td><td>TEC Register Frozen on 31 October</td><td></td></tr>
<tr><td>Network Model</td><td colspan="2">Initial update using previous year’s data source (except local circuit changes which are updated quarterly)</td><td>Latest version based on ETYS</td><td></td></tr>
<tr><td>CPIH</td><td colspan="3">forecast</td><td>Actual</td></tr>
<tr><td rowspan="7">RESIDUAL / ADJUSTMENT</td><td>OFTO Revenue (part of allowed revenue)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>NG best view</td></tr>
<tr><td>Allowed Revenue (non OFTO changes)</td><td>Initial update using previous year’s data source</td><td>Update financial parameters</td><td>Latest TO forecasts</td><td>From TOs</td></tr>
<tr><td>Demand Charging Bases</td><td>Initial update using previous year’s data source</td><td>Revised forecast</td><td>Revised forecast</td><td>Revised by exception</td></tr>
<tr><td>Banding Data</td><td colspan="2">Previous year’s data source</td><td>DNO/IDNO consumption and site data updated</td><td></td></tr>
<tr><td>Generation Charging Base</td><td>NG best view</td><td>NG best view</td><td>NG best view</td><td>NG final best view</td></tr>
<tr><td>Generation ALFs</td><td colspan="2">Previous year’s data source</td><td>New ALFs published</td><td></td></tr>
<tr><td>Generation Revenue (G/D split)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>Generation revenue £m fixed</td></tr>
</table>

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