Draft TNUoS Tariffs for 2023/24

Electricity System Operator

November 2022

ESO

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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 Draft TNUoS Tariffs for 2023/24.

Under the National Grid Electricity System Operator (ESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish this forecast of Transmission Network Use of System (TNUoS) tariffs for year 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

Commission Regulation (EU) No. 838/2010 (which is retained EU law) sets out that the annual average transmission charges paid by producers in Great Britain must fall within €0-2.50/MWh.

There have been a number of code modifications to update the CUSC in relation to this regulation and specifically there have been legal challenges resulting from Ofgem's decision to approve CUSC Modification Proposal CMP317/327.

The judgement of the Court of Appeal in the appeals brought by Ofgem and SSE in relation to this matter has been published[2]. Ofgem have also issued an open letter[3] .

We are working with Ofgem to understand the next steps. We will communicate with industry as soon as practicable.

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.

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

[2] https://caselaw.nationalarchives.gov.uk/ewca/civ/2022/1472

Total revenues to be recovered

The total TNUoS revenue is forecast at £3,983.4m for 23/24, a reduction of -£97.2m from the August forecast. This is due to revisions of the TO MAR (+£60.3m), revisions to OFTO Allowed revenue & Interconnector revenue contributions (-£135m). Other pass-through costs (-£22.5m). The 2023/24 revenue forecast will be finalised by January Final Tariffs based on updated revenue data by Onshore and Offshore TOs' submissions.

Generation tariffs

The total revenue to be recovered from generators is forecast at £930.0m for 2023/24, an increase of £10.9m since the August forecast.

The generation charging base has been forecast to be 75.96GW based on our best view on generation projects for 2023/24. This is a decrease of 1.22GW since the August forecast. This view will be further refined in the final tariffs. The average generation tariff is £12.24/kW, an increase of £0.33/kW due to the increase in generation revenue and decrease in the charging base.

Demand tariffs

Revenue to be collected through demand is forecast at £3,053m for 2023/24, a £108.5m reduction since the August tariffs. The main driver is the reduction in revenue to be collected in total through TNUoS and an increase in the proportion of revenue to be recovered from generation.

The impact on the end consumer is forecast to be £39.68 per household in 2023/24, a reduction of £0.41 from August tariffs. This is due to the reduction in the total demand revenue.

[3] https://www.ofgem.gov.uk/publications/cmp317-cmp327-excluding-assets-required-connection-and-removing-transmission-generator-residual

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

In 2023/24 it is forecast that £20.4m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £3.2m since the August 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 £2.67/kW, which is an increase of £0.41/kW versus August tariffs.

The average gross HH demand tariff for 2023/24 is to be £5.33/kW, an increase of £0.05/kW and the average NHH demand tariff forecast is at 0.26p/kWh, an increase of 0.006p/kWh since August 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 Final 2023/24 tariffs in January 2023.

Feedback

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

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

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

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

Charging Methodology Changes

This Report

This report contains the Draft 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

Since this year, 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 daily charge per site across the banding categories and thresholds. We will continue to provide further updates on follow-up mods (for example, CMP389) as they are raised. It is expected that the decision on CMP389 will be made by December. If approved, the TDR tariffs for transmission-connected demand users band thresholds will change.

As part of TCR implementation, CMP391: Definition of ‘Charges for Physical Assets Required for Connection’ (PARC) is also applied 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 original definition of “Charges for Physical Assets Required for Connection” from CUSC section 11. The amended definition of PARC reflects the Limiting Regulation which includes local charges associated with pre-existing assets into the calculation of generation charge (for the purpose of compliance with the €0 – 2.5/MWh range. For individual users, their 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

There have been a number of code modifications to update the CUSC in relation to the Limiting Regulation of average generation charge (within the range of €0-2.50/MWh), and specifically there have been legal challenges resulting from Ofgem's decision to approve CUSC Modification Proposal CMP317/327.

The judgement of the Court of Appeal in the appeals brought by Ofgem and SSE in relation to this matter has been published on 8th November. Ofgem have also issued an open letter on the same day.

We are working with Ofgem to understand the next steps. We will communicate with industry as soon as practicable.

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

TNUoS Reform

In May 2022, Ofgem published an open letter[7] outlining their latest thinking on the scope of the work to be undertaken by a Task Force and asked the Electricity System Operator to work with industry to establish membership. In the letter, Ofgem clarified that the Task Forces will look at improvements to today's methodology whilst keeping its core assumptions and modelling approach unchanged. They stated that this does not rule out significant changes to elements of TNUoS, for example, the transport model, changes to the 'backgrounds' against which charges are calculated, or the approach to the demand-weighted distributed reference node.

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/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 August	2023/24 November	Change since last forecast
Adjustment	- 1.548377	- 0.905944	0.642433
Average Generation Tariff*	11.909194	12.242807	0.333613

*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, TNUoS local charges associated with pre-existing assets are included in the €2.50/MWh cap.

Average generation tariffs have increased by £0.33/kW, due to an increase of £10.9m in the revenue to be collected from generation and the 1.22GW decrease in the generation charging base compared to the August forecast. The generation adjustment has increased by £0.64/kW, decreasing in magnitude, to become less negative; this is partly due to alignment of the adjustment tariffs with the CUSC methodology; and more importantly, the wider tariff components have decreased for most zones, meaning there is less of an adjustment required to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 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		
Battery storage		
Reactive Compensation		

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

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

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

Table 2 Generation wider tariffs

Generation Tariffs						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	2.558709	20.305939	17.235592	-0.905944	16.669377	34.117811	25.467321
2	East Aberdeenshire	3.171138	11.427984	17.235592	-0.905944	13.730624	28.071774	21.472241
3	Western Highlands	2.710368	18.493578	16.686853	-0.905944	15.876596	32.361461	24.103019
4	Skye and Lochalsh	2.626662	18.493578	23.249693	-0.905944	18.418026	38.840595	30.665859
5	Eastern Grampian and Tayside	3.700935	13.332871	14.334388	-0.905944	13.861895	27.129032	19.428236
6	Central Grampian	3.328099	13.788852	14.755544	-0.905944	13.839913	27.519338	20.054583
7	Argyll	2.700601	11.596102	21.623762	-0.905944	15.082603	32.115496	25.936064
8	The Trossachs	2.800923	11.596102	12.689997	-0.905944	11.609419	23.282053	17.002299
9	Stirlingshire and Fife	2.103830	10.674622	12.039268	-0.905944	10.283442	21.243121	15.936904
10	South West Scotlands	0.370923	11.025484	12.264853	-0.905944	8.781114	19.998945	16.320377
11	Lothian and Borders	3.605846	11.025484	7.386751	-0.905944	10.064796	18.355766	11.442275
12	Solway and Cheviot	1.146695	7.291170	6.952777	-0.905944	5.938330	12.661906	9.327860
13	North East England	3.832599	5.572265	4.386436	-0.905944	6.910135	11.492290	5.988011
14	North Lancashire and The Lakes	0.908507	5.572265	1.478619	-0.905944	2.822917	5.660381	3.080194
15	South Lancashire, Yorkshire and Humber	4.545364	2.018955	0.292103	-0.905944	4.563843	5.445739	0.294689
16	North Midlands and North Wales	2.975847	0.674119	-	-0.905944	2.339551	2.575492	-0.602590
17	South Lincolnshire and North Norfolk	1.934573	2.933009	-	-0.905944	2.201833	3.228386	0.413910
18	Mid Wales and The Midlands	1.004435	2.880546	-	-0.905944	1.250709	2.258901	0.390302
19	Anglesey and Snowdon	4.248151	0.751303	-	-0.905944	3.642728	3.905684	-0.567858
20	Pembrokeshire	6.776956	-8.818684	-	-0.905944	2.343538	-0.743001	-4.874352
21	South Wales & Gloucester	1.831177	-8.700561	-	-0.905944	-2.554991	-5.600188	-4.821196
22	Cotswold	1.157805	4.331887	-11.779252	-0.905944	-2.727085	-8.278476	-10.735847
23	Central London	-3.516583	4.331887	-3.935042	-0.905944	-4.263789	-5.108654	-2.891637
24	Essex and Kent	-2.815943	4.331887	-	-0.905944	-1.989132	-0.472972	1.043405
25	Oxfordshire, Surrey and Sussex	-0.353416	-1.860957	-	-0.905944	-2.003743	-2.655078	-1.743375
26	Somerset and Wessex	-0.786734	-2.609986	-	-0.905944	-2.736672	-3.650168	-2.080438
27	West Devon and Cornwall	-1.216180	-7.435294	-	-0.905944	-5.096242	-7.698595	-4.251826

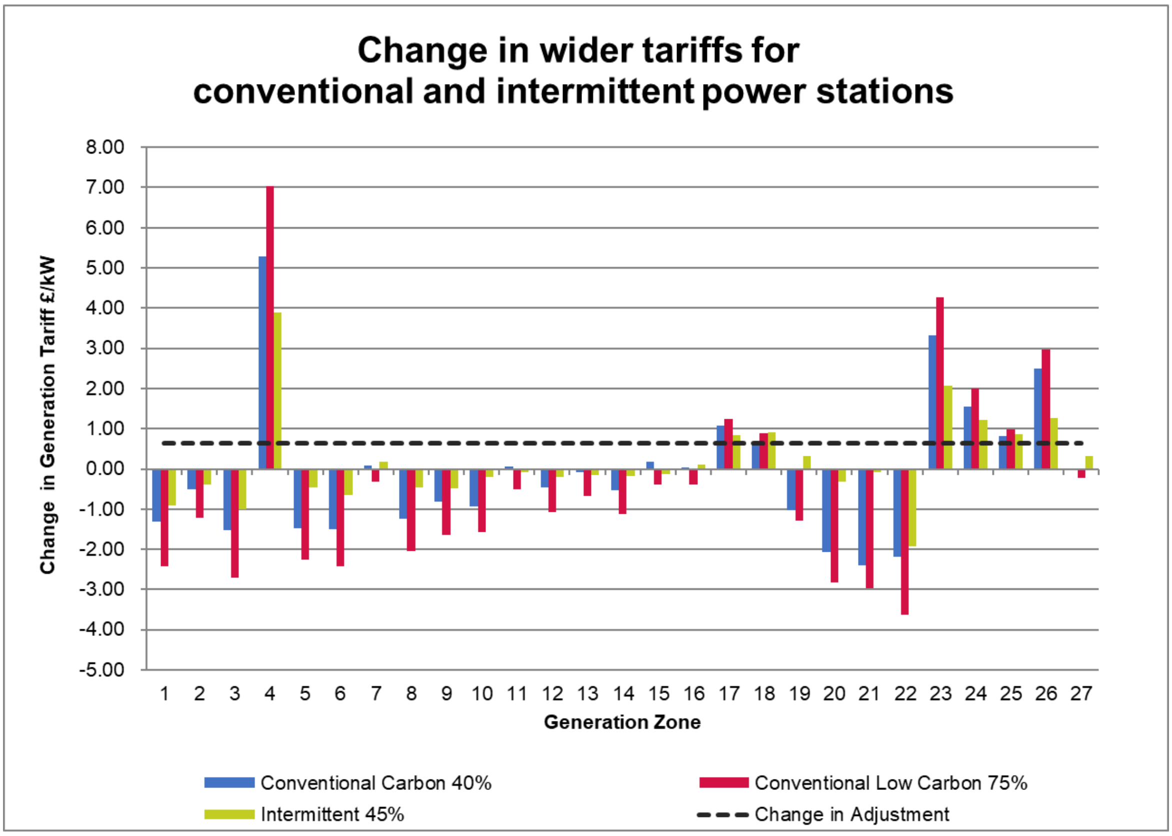
3. Changes to wider tariffs since the August Forecast

The following section provides details of the wider generation tariffs for 2023/24 and explains how these have changed since the August 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

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
Zone	Zone Name	2023/24 August	2023/24 November	Change	2023/24 August	2023/24 November	Change	2023/24 August	2023/24 November	Change	Change in Adjustment
1	North Scotland	17.976549	16.669377	-1.307171	36.545665	34.117811	-2.427853	26.379263	25.467321	-0.911942	0.642433
2	East Aberdeenshire	14.238462	13.730624	-0.507838	29.289697	28.071774	-1.217923	21.856273	21.472241	-0.384033	0.642433
3	Western Highlands	17.394833	15.876596	-1.518236	35.058129	32.361461	-2.696668	25.099543	24.103019	-0.996524	0.642433
4	Skye and Lochalsh	13.133963	18.418026	5.284064	31.809435	38.840595	7.031160	26.786503	30.665859	3.879357	0.642433
5	Eastern Grampian and Tayside	15.328667	13.861895	-1.466772	29.394077	27.129032	-2.265045	19.880565	19.428236	-0.452329	0.642433
6	Central Grampian	15.332204	13.839913	-1.492291	29.945193	27.519338	-2.425855	20.712020	20.054583	-0.657436	0.642433
7	Argyll	14.991959	15.082603	0.090643	32.439297	32.115496	-0.323801	25.749824	25.936064	0.186240	0.642433
8	The Trossachs	12.859755	11.609419	-1.250336	25.329440	23.282053	-2.047387	17.453737	17.002299	-0.451438	0.642433
9	Stirlingshire and Fife	11.100050	10.283442	-0.816608	22.874210	21.243121	-1.631090	16.414980	15.936904	-0.478076	0.642433
10	South West Scotlands	9.724347	8.781114	-0.943233	21.570791	19.998945	-1.571846	16.522291	16.320377	-0.201914	0.642433
11	Lothian and Borders	10.004227	10.064796	0.060569	18.852819	18.355766	-0.497053	11.525871	11.442275	-0.083596	0.642433
12	Solway and Cheviot	6.387965	5.938330	-0.449635	13.740262	12.661906	-1.078357	9.537927	9.327860	-0.210068	0.642433
13	North East England	6.991204	6.910135	-0.081068	12.156100	11.492290	-0.663811	6.129235	5.988011	-0.141223	0.642433
14	North Lancashire and The Lakes	3.345740	2.822917	-0.522824	6.789287	5.660381	-1.128907	3.260319	3.080194	-0.180124	0.642433
15	South Lancashire, Yorkshire and Humber	4.375075	4.563843	0.188768	5.838219	5.445739	-0.392480	0.424892	0.294689	-0.130203	0.642433
16	North Midlands and North Wales	2.311793	2.339551	0.027758	2.962802	2.575492	-0.387310	-0.711366	-0.602590	0.108775	0.642433
17	South Lincolnshire and North Norfolk	1.117810	2.201833	1.084023	1.996397	3.228386	1.231989	-0.418765	0.413910	0.832675	0.642433
18	Mid Wales and The Midlands	0.573619	1.250709	0.677091	1.372688	2.258901	0.886213	-0.521003	0.390302	0.911304	0.642433
19	Anglesey and Snowdon	4.669748	3.642728	-1.027020	5.190362	3.905684	-1.284678	-0.879016	-0.567858	0.311159	0.642433
20	Pembrokeshire	4.419673	2.343538	-2.076135	2.089054	-0.743001	-2.832055	-4.544888	-4.874352	-0.329463	0.642433
21	South Wales & Gloucester	-0.149661	-2.554991	-2.405330	-2.636204	-5.600188	-2.963984	-4.745360	-4.821196	-0.075837	0.642433
22	Cotswold	-0.532350	-2.727085	-2.194735	-4.638870	-8.278476	-3.639606	-8.800764	-10.735847	-1.935083	0.642433
23	Central London	-7.576094	-4.263789	3.312305	-9.375784	-5.108654	4.267130	-4.956047	-2.891637	2.064410	0.642433
24	Essex and Kent	-3.542354	-1.989132	1.553221	-2.470862	-0.472972	1.997890	-0.170744	1.043405	1.214149	0.642433
25	Oxfordshire, Surrey and Sussex	-2.817949	-2.003743	0.814207	-3.636330	-2.655078	0.981253	-2.600581	-1.743375	0.857206	0.642433
26	Somerset and Wessex	-5.220100	-2.736672	2.483427	-6.620902	-3.650168	2.970735	-3.349408	-2.080438	1.268971	0.642433
27	West Devon and Cornwall	-5.110020	-5.096242	0.013778	-7.468053	-7.698595	-0.230541	-4.580135	-4.251826	0.328308	0.642433

Figure 1 Variation in generation wider zonal tariffs



Locational changes

Locational tariffs have been impacted by the update of various locational inputs, including the nodal generation and demand and the network model used to model flows. This means that there have been changes in the overall tariffs across each generation zone. In particular, the change in flows has resulted in a large increase in zone 4, which is often sensitive to small changes in flows due to local generation and demand being nearly matching, and the long radial circuits. Overall, the North-South tariff divide has decreased (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 increased by £0.64/kW since the August forecast, decreasing in magnitude, to become less negative. This is mainly due to changes to locational tariffs which results in less wider revenue expected to be collected from generators. These changes cause the adjustment to go less negative as there is less adjustment required to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see Table 22. In addition, we have reviewed the calculation approach to fully align with the CUSC following CMP391.

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 finalised, and therefore onshore local substation tariffs are finalised for charging year 2023/24.

Table 4 Local substation tariffs

2023/24 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.163811	0.081909	0.056497
<1320 MW	Redundancy	0.345168	0.175316	0.124485
>=1320 MW	No redundancy	-	0.240647	0.171334
>=1320 MW	Redundancy	-	0.362133	0.260462

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 finalised. 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	2.902034	Dumnaglass	0.968386	Langage	- 0.375074
Achruach	4.779480	Dunhill	1.594208	Lochay	0.416560
Aigas	0.744492	Dunlaw Extension	1.685580	Luichart	0.641683
An Suidhe	- 1.068738	Edinbane	7.793870	Marchwood	0.425506
Arecleoch	2.645559	Enoch Hill	1.669108	Mark Hill	0.996676
Beinneun Wind Farm	1.499498	Ewe Hill	1.692970	Middle Muir	2.615649
Bhlaraidh Wind Farm	0.734958	Fallago	- 0.073578	Middleton	0.167453
Black Hill	1.728519	Farr	3.968392	Millennium Wind	1.868744
Black Law	1.989073	Fernoch	5.007516	Mossford	3.208094
BlackCraig Wind Farm	6.615841	Ffestiniogg	0.281594	Nant	2.857146
BlackLaw Extension	4.218087	Finlarig	0.364490	Necton	- 0.425691
Broken Cross	1.214600	Foyers	0.326024	Rhigos	0.117344
Clyde (North)	0.124836	Galawhistle	1.162128	Rocksavage	0.020105
Clyde (South)	0.144367	Glen Kyllachy	0.520700	Saltend	- 0.002284
Corriegarth	2.777066	Glendoe	2.093849	Sandy Knowe	3.589189
Corriemoillie	1.855154	Glenglass	5.278109	South Humber Bank	- 0.206681
Coryton	0.049691	Gordonbush	0.011052	Spalding	0.304901
CREAG RIABHACH	3.818465	Griffin Wind	10.799672	Strathbrora	- 0.115199
Cruachan	2.032133	Hadyard Hill	3.150753	Strathy Wind	1.932256
Culligran	1.972922	Harestanes	2.660776	Stronelairg	1.222997
Cumberhead Collector	0.795543	Hartlepool	0.670932	Wester Dod	0.387343
Deanie	3.241230	Invergarry	0.416560	Whitelee	0.120809
Dersalloch	2.742000	Kennoxhead	4.554787	Whitelee Extension	0.335850
Dinorwig	2.670461	Kilgallioch	1.198025		
Dorenell	2.335836	Kilmorack	0.224810		
Douglas North	0.781050	Kype Muir	1.688418		

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

Table 6 Circuits subject to one-off charges

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

Offshore local tariffs for generation

6. Offshore local generation tariffs

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

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 August Tariff Component (£/kW)			2023/24 November Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	10.139060	53.564132	1.330071	10.232463	54.057574	1.342324	0.093403	0.493442	0.012253
Beatrice	8.268518	22.670872	-	8.398974	23.028560	-	0.130456	0.357688	-
Burbo Bank	12.842889	24.821369	-	13.045517	25.212986	-	0.202628	0.391617	-
Dudgeon	18.784754	29.473568	-	19.081129	29.938585	-	0.296375	0.465017	-
Galloper	19.228736	30.412224	-	19.532116	30.892051	-	0.303380	0.479827	-
Greater Gabbard	18.891175	43.716078	-	19.065204	44.118799	-	0.174029	0.402721	-
Gunfleet	22.064750	20.347658	3.803094	22.268014	20.535104	3.838129	0.203264	0.187446	0.035035
Gwynt y mor	24.117382	23.844424	-	24.497892	24.220627	-	0.380510	0.376203	-
Hornsea 1A	8.584024	30.371617	-	8.719458	30.850803	-	0.135434	0.479186	-
Hornsea 1B	8.584024	30.371617	-	8.719458	30.850803	-	0.135434	0.479186	-
Hornsea 1C	8.584024	30.371617	-	8.719458	30.850803	-	0.135434	0.479186	-
Humber Gateway	14.193214	32.564116	-	14.417146	33.077894	-	0.223932	0.513778	-
Lincs	19.703571	77.487408	-	20.014443	78.709959	-	0.310872	1.222551	-
London Array	13.371264	45.844940	-	13.582228	46.568255	-	0.210964	0.723315	-
Ormonde	31.173208	58.269483	0.464359	31.460381	58.806272	0.468637	0.287173	0.536789	0.004278
Race Bank	11.375530	31.595073	-	11.555007	32.093562	-	0.179477	0.498489	-
Rampion	9.292713	24.309342	-	9.439328	24.692880	-			
Robin Rigg	-0.684212	38.837314	12.443228	-0.690516	39.195090	12.557858	-0.006304	0.357776	0.114630
Robin Rigg West	-0.684212	38.837314	12.443228	-0.690516	39.195090	12.557858	-0.006304	0.357776	0.114630
Sheringham Shoal	29.164957	34.349233	0.746651	29.433630	34.665665	0.753530	0.268673	0.316432	0.006879
Thanet	22.271109	41.724974	1.004467	22.476275	42.109352	1.013720	0.205166	0.384378	0.009253
Walney 1	26.924230	53.828381	-	27.172261	54.324258	-	0.248031	0.495877	-
Walney 2	25.049047	50.977306	-	25.279803	51.446918	-	0.230756	0.469612	-
Walney 3	11.685008	23.673126	-	11.869367	24.046627	-	0.184359	0.373501	-
Walney 4	11.685008	23.673126	-	11.869367	24.046627	-	0.184359	0.373501	-
West of Duddon Sands	10.450183	52.092796	-	10.615060	52.914686	-	0.164877	0.821890	-
Westermost Rough	21.248698	36.162582	-	21.583947	36.733135	-	0.335249	0.570553	-

Demand Tariffs

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

ESO

7. Demand tariffs summary

There are two types of demand, Half-Hourly (HH) and Non-Half-Hourly (NHH). 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 August 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 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 August	2023/24 November	Change
Average (£/site/annum)	97.687198	92.746325	- 4.940873
Unmetered (p/kWh)	1.1660356	0.0031860	- 1.1628496
Demand Residual (£m)	3,074.4	2,968.6	- 105.9

HH Tariffs (Locational)	2023/24 August	2023/24 November	Change
Average Tariff (£/kW)	5.281208	5.328366	0.047158
Residual (£/kW)	-	0.000000	0.000000

EET	2023/24 August	2023/24 November	Change
Average Tariff (£/kW)	2.252783	2.667967	0.415183
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.540292	2.547308	0.007016
Embedded Export Volume (GW)	7.643273	7.641359	- 0.001914
Total Credit (£m)	17.218637	20.386890	3.168253

NHH Tariffs (locational)	2023/24 August	2023/24 November	Change
Average (p/kWh)	0.250808	0.256769	0.005961

Since the publication of the August tariffs, average HH & NHH demand tariffs have seen a small increase, the main driver being the increase in the total amount of revenue to be recovered through TNUoS locational element of demand tariffs. The current draft tariffs for 2023/24 indicate that 76.65% of total revenue is to be recovered through demand, a reduction of 0.8% since August tariffs, with overall demand revenue set at £2,968m (reduction of £105.85m from August tariffs).

The average HH gross tariff is set at £5.32/kW, an increase of £0.05/kW compared to August tariffs. The average NHH tariff is forecast at 0.26p/kWh, an increase of 0.005p/kWh.

Embedded Export Volume 7.64GW is similar compared to the August tariff forecast. However, there has been a noticeable increase in the total credit paid out to embedded generators (<100MW), which is currently forecast at £20.39m, an increase of £3.17m. 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 £2.67/kW an increase of £0.42/kW compared to the August 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	-	-	0.410283
7	East Midlands	-	-	2.051847
8	Midlands	3.046892	0.383934	5.594200
9	Eastern	0.272515	0.036455	2.819823
10	South Wales	6.689801	0.761901	9.237109
11	South East	2.928529	0.387454	5.475837
12	London	4.374542	0.452197	6.921850
13	Southern	5.290615	0.674743	7.837923
14	South Western	7.645707	1.050876	10.193015

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 Final 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 August	2023/24 Draft	Change
Domestic	Tariff - £/Site/Day	0.11	0.10	0.00
LV_NoMIC_1		0.04	0.05	-0.01
LV_NoMIC_2		0.25	0.24	0.00
LV_NoMIC_3		0.60	0.58	0.03
LV_NoMIC_4		1.91	1.80	0.11
LV1		3.05	2.90	0.14
LV2		5.72	5.33	0.39
LV3		9.30	8.68	0.62
LV4		21.13	19.55	1.58
HV1		14.10	15.13	-1.03
HV2		51.05	48.70	2.35
HV3		99.74	95.62	4.12
HV4		256.96	242.69	14.28
EHV1		160.24	114.52	45.73
EHV2		620.65	563.07	57.58
EHV3		1,312.55	1,135.33	177.22
EHV4		3,394.62	3,091.83	302.79
T-Demand1		388.88	435.08	-46.20
T-Demand2		1,391.71	1,342.07	49.63
T-Demand3		3,037.19	3,115.11	-77.92
T-Demand4		8,894.52	8,000.77	893.75
Unmetered demand		**p/kWh**	**p/kWh**	
Unmetered		0.00319	0.00299	0.00020
Demand Residual (£m)		**3,074.4**	**2,968.6**	**-105.9**

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 2020/21 to 2021/22 and the sites connected over that time. The transmission thresholds will be refined as we progress through to 2023/24 Final 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 2021/22 provided by the DNO/IDNO's latest submission in October/November 2022, 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 2022/23 by the DNO/IDNO's in October 2023. The transmission connected out-turn demand data for 2022/23 which the ESO produces will also be made available at the same time. These updated values will be included in the 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.

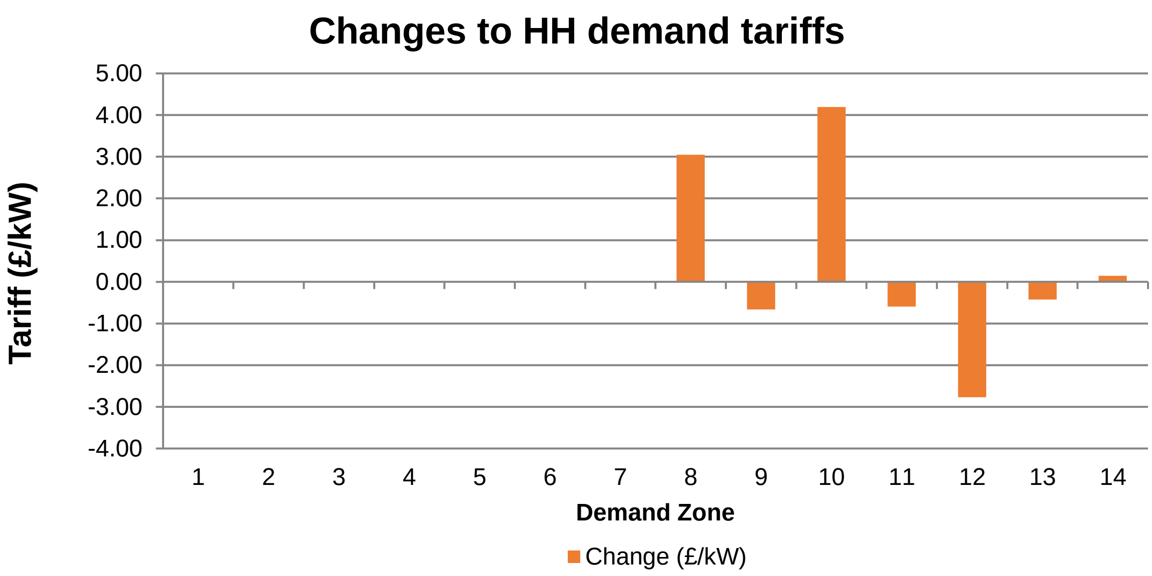
9. Half-Hourly demand tariffs

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

Table 11 Half-Hourly demand tariffs

Zone	Zone Name	2023/24 August (£/kW)	2023/24 November (£/kW)	Change (£/kW)	Change in Residual (£/kW) (n/a)
1	Northern Scotland	-	-	-	0.000000
2	Southern Scotland	-	-	-	0.000000
3	Northern	-	-	-	0.000000
4	North West	-	-	-	0.000000
5	Yorkshire	-	-	-	0.000000
6	N Wales & Mersey	-	-	-	0.000000
7	East Midlands	-	-	-	0.000000
8	Midlands	-	3.046892	3.046892	0.000000
9	Eastern	0.933038	0.272515	- 0.660523	0.000000
10	South Wales	2.493406	6.689801	4.196395	0.000000
11	South East	3.520830	2.928529	- 0.592301	0.000000
12	London	7.145918	4.374542	- 2.771376	0.000000
13	Southern	5.712609	5.290615	- 0.421994	0.000000
14	South Western	7.499372	7.645707	0.146335	0.000000

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the fluctuations in tariffs for zones 8 through to 14 tariffs are due to a combination of an increase in the forecast Expansion Constant (EC) an increase of £0.2 £/MWkm since August tariffs, 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 0.01GW in comparison with the August tariffs and is currently forecast at 19.76GW.

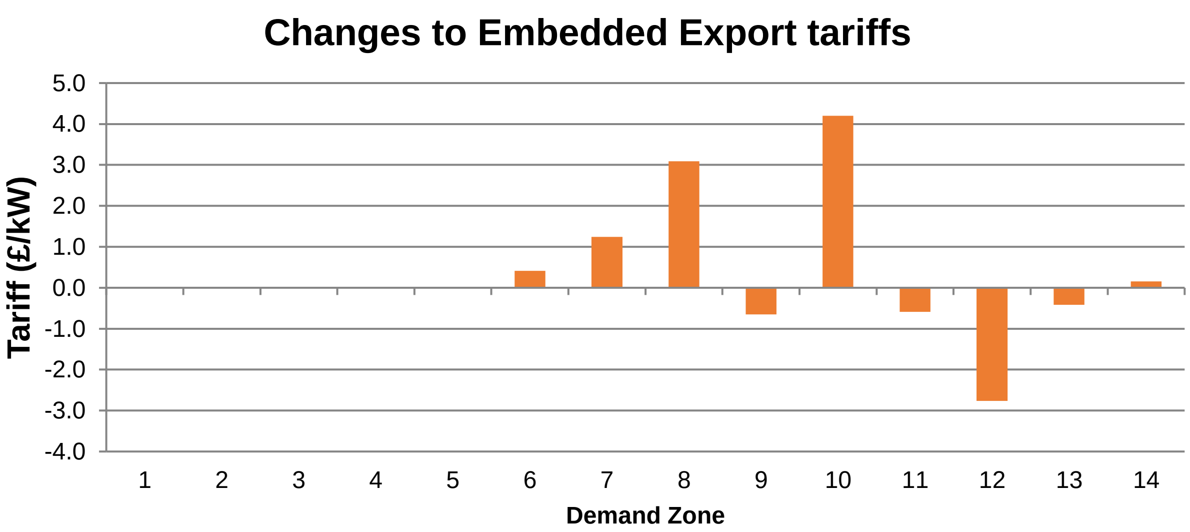
10. Embedded Export Tariffs (EET)

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

Table 12 Embedded Export Tariffs

Zone	Zone Name	2023/24 August (£/kW)	2023/24 November (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	0.410283	0.410283
7	East Midlands	0.812237	2.051847	1.239610
8	Midlands	2.505729	5.594200	3.088471
9	Eastern	3.473330	2.819823	- 0.653507
10	South Wales	5.033698	9.237109	4.203411
11	South East	6.061122	5.475837	- 0.585285
12	London	9.686210	6.921850	- 2.764360
13	Southern	8.252901	7.837923	- 0.414978
14	South Western	10.039664	10.193015	0.153351

Figure 3 Embedded export tariff changes



In this tariff update there has been noticeable change to the average EET versus the August forecast. This is primarily due to a change in locational demand and a change in forecast Embedded Export Volumes. The changes in locational demand tariffs and the corresponding impact of the update to Week 24 demand data can be seen in Table 25. The Embedded Export Volume has remained similar with the previous forecast of 7.64Gwh. There has been a slight increase to the avoided GSP Infrastructure Costs (AGIC) of £0.007/kW to £2.55/kW due to an increase in inflation for 2023/24. The overall impact of these changes has increased the average EET by £0.42/kW to £2.67/kW.

As can be seen in the figure above there has been a reduction in Zones 9 & 11 - 14. With an increase in Zones 6 – 8 & 10. Zones 1-5 remain floored at £0/kW and have subsequently no movement.

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.

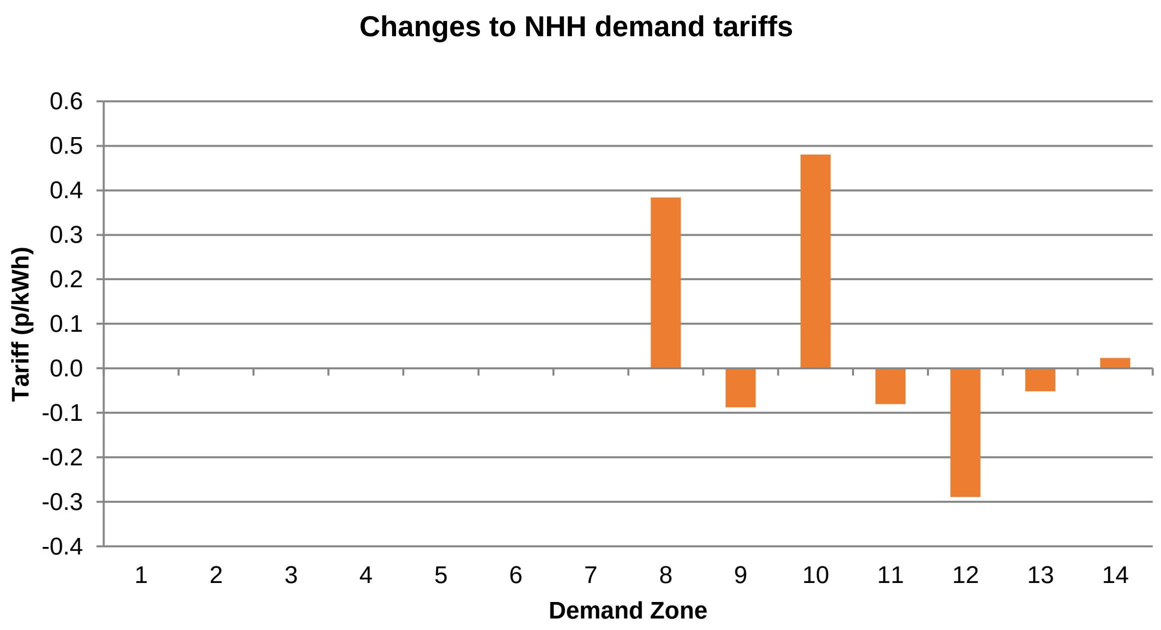
11. Non-Half-Hourly demand tariffs

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

Table 13 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2023/24 August (p/kWh)	2023/24 November (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	-	0.383934	0.383934
9	Eastern	0.124251	0.036455	-0.087796
10	South Wales	0.281869	0.761901	0.480032
11	South East	0.467587	0.387454	-0.080133
12	London	0.741324	0.452197	-0.289127
13	Southern	0.726061	0.674743	-0.051318
14	South Western	1.027589	1.050876	0.023287

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2023/24 Final tariffs is set at 0.26p/kWh, a 0.005p/kWh increase compared to August tariffs. As with the HH tariffs and the EET, the fluctuations to NHH tariffs since August tariffs has been the combination of an increase in the forecast of EC and changes to Demand Charging Bases.

Overview of data inputs

ESO

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

12. Inputs affecting the locational element of tariffs

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

- Contracted position of generation;
- Nodal demand;
- Local and MITS circuits;
- Inflation;
- Locational security factor
- Expansion constant

Contracted, 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.[8] The contracted TEC volumes are based on the October 2022 TEC register.

Modelled Best View TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the Initial and August forecasts, we forecast our best view of modelled TEC. However, for our November Draft tariffs and January Final tariffs we use the contracted TEC position as published in TEC register as of 31st October 2022, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2023/24 and liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2023.

Table 14 Contracted, Modelled & Chargeable TEC

	2023/24 Tariffs			
Generation (GW)	Initial	August	Draft	Final
Contracted TEC	90.96	88.69	89.77	
Modelled Best View TEC	85.11	87.40	89.77	
Chargeable TEC	74.89	77.18	75.96	

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 31st October 2022.

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

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 £16.800286/MWkm. 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 guide to the onshore security factor calculation is published on our website https://www.nationalgrideso.com/document/183406/download

16. Onshore substation tariffs

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

For this 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 – 2025/26), and parameters including project spending profiles, rate of return and inflation index are set at the beginning of each price control period. Onshore TOs' allowed revenue figures are published annually on Ofgem's website after the Annual Iteration Process (AIP).

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	2,141.3	
Scottish Power Transmission	421.2	443.6	498.2	
SHE Transmission	712.4	750.2	711.9	
Total TO Income from TNUoS	**3,125.2**	**3,291.1**	**3,351.4**	
Other Income from TNUoS				
Other Pass-through from TNUoS	87.0	38.3	15.8	
Offshore (plus interconnector contribution / allowance)	735.2	751.2	616.2	
Total Other Income from TNUoS	**822.2**	**789.5**	**632.0**	
Total to Collect from TNUoS	**3,947.3**	**4,080.6**	**3,983.4**	

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.

CMP391 (definition of the term "Charges for Physical Assets Required for Connection") is incorporated in this forecast. Majority of TNUoS local charges (including onshore and offshore local charges) fall into the definition of Charges for Physical Assets Required for Connection (PARC), however, a small part of the TNUoS onshore local charges (about £2.6m in this forecast) are categorised as charges associated with pre-existing assets, and are therefore not PARC.

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

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	2.5	
y	Error Margin	14.2%	23.6%	23.6%	
ER	Exchange Rate (€/£)	1.17	1.19	1.19	
MAR	Total Revenue (£m)	3,947.0	4,080.6	3,983.4	
GO	Generation Output (TWh)	194.9	199.8	199.8	
G	% of revenue from generation	23.92%	22.52%	23.35%	
D	% of revenue from demand	76.08%	77.48%	76.65%	
G.R	Revenue recovered from generation (£m)	944.2	919.1	930.0	
D.R	Revenue recovered from demand (£m)	3,002.8	3,161.5	3,053.4	
Breakdown of generation revenue					
	Revenue from the Peak element	129.3	115.1	103.3	
	Revenue from the Year Round Shared element	124.3	149.5	117.5	
	Revenue from the Year Round Not Shared element	176.2	174.5	167.6	
	Revenue from Onshore Local Circuit tariffs	17.1	17.3	17.5	
	Revenue from Onshore Local Substation tariffs	10.7	11.0	10.9	
	Revenue from Offshore Local tariffs	558.6	571.1	582.0	
	Revenue from the adjustment element	-71.9	-119.5	-68.8	
G.MAR	Total Revenue recovered from generation (£m)	944.2	919.1	930.0	
	Including revenue from large embedded generation (£m)*	*	9.3	*	
	Including revenue from local charges associated with pre-existing assets (indicative) (£m)	*	2.4	2.6	

*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 €0 - 2.5/MWh. The revenue that can be recovered from generation is dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy. This revenue limit figure was referred to as the “gen cap” which is part of the UK law. 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 CUSC for the purpose of maintaining compliance with the Limiting Regulation (the [0 ~ €2.50]/MWh range). Following CMA’s Order[9] on 20 May 2022, we have incorporated CMP391 in the calculation of generation revenue (inclusion of local charges associated with pre-existing assets, in the gen cap compliance calculation).

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. The figure has been finalised, as per OBR’s March EFO, at €1.193850/£.

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.

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

Error Margin

The error margin was updated and finalised in the August 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 implementation 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)	0.744492	
Aikengall IIa Wind Farm	0.387343	
An Suidhe Wind Farm - Argyll (SRO)	- 1.068738	
Blackcraig Wind Farm	6.615841	
Broken Cross Wind Farm	1.214600	
Corriemoillie Wind Farm	1.855154	
Culligran (part of the Beauly Cascade)	1.972922	
Cumberhead	0.795543	
Dalquhandy Wind Farm	0.795543	
Deanie (part of the Beauly Cascade)	3.241230	
Edinbane Windfarm	7.793870	
Farr Wind Farm - Tomatin	3.968392	
Ffestiniog	0.281594	
Finlarig	0.364490	
Foyers	0.326024	
Glendoe	2.093849	6380
Hirwaun Power Station	0.117344	
Invergarry (part of the Garry Cascade)	0.416560	
Keith Hill Wind Farm	1.685580	
Kilbraur Wind Farm	- 0.115199	
Kilgallioch	1.198025	
Luichart (part of the Conon Cascade)	0.641683	
Mark Hill Wind Farm	0.996676	
Mossford (part of the Conon Cascade)	3.208094	
Nant	2.857146	
Rocksavage	0.020105	
Saltend	- 0.002284	
South Humber Bank	- 0.206681	
Spalding	0.304901	
Strathy North Wind	1.932256	
Tralorg Wind Farm	0.996676	

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	0.345168	
Toddleburn Wind Farm	0.345168	41.7
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 75.96GW, which is a decrease of 1.22GW since the August forecast. It is based on our internal view of what generation we expect to connect next financial year.

For the Draft Tariffs (and subsequent Final Tariffs), in line with the CUSC, we 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 August 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	75.97	
NHH Demand (4pm-7pm TWh)	24.54	24.86	24.97	
Gross charging				
Total Average Gross Triad (GW)	49.72	50.67	50.95	
HH Demand Average Gross Triad (GW)	19.48	19.75	19.76	
Embedded Generation Export (GW)	7.38	7.64	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 draft version of the 2023/24 ALFs. ALFs are explained in more detail in Appendix D of this report, and the full list of power station ALFs are available on the ESO website.[10]

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.

[10] https://www.nationalgrideso.com/document/272251/download

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 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.

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%	23.35%	
D	Proportion of revenue recovered from demand (%)	76.08%	77.48%	76.65%	
R	Total TNUoS revenue (£m)	3,947.0	4,080.6	3,983.4	
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	429.8	439.1	388.4	
O	Revenue recovered from offshore local tariffs (£m)	558.6	571.1	582.0	
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.7	11.0	10.9	
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.1	17.3	17.5	
	Revenue from large embedded generation (£m)	*	9.3	*	
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	*	2.4	2.6	
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	
	Error Margin	14.2%	23.6%	23.6%	
	Exchange Rate (€/£)	1.17	1.19	1.19	
	Total generation Output (TWh)	194.9	199.8	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	319.4	
	Adjustment Revenue (£m)	-71.9	-119.7	-68.8	
BG	Generator charging base (GW)	74.9	77.2	76.0	
AdjTariff	Generator adjusment tariff (£/kW)	-0.96	-1.55	-0.91	
Gross demand residual					
R_D	Demand residual (£m)	2,925.6	3,074.4	2,968.6	
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	92.9	104.3	105.3	
EE	Amount to be paid to Embedded Export Tariffs (£m)	15.6	17.2	20.4	
B_D	Demand Gross charging base (GW)	49.7	50.6	50.9	

*Not applicable for this forecast

Tools and supporting information

ESO

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

Charging webinars

We will be hosting a webinar for the Draft Tariff forecast on Thursday 15th December. 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/272331/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

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, ESO determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: Peak Demand and Year Round, where a change in demand or generation increases power flows, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced. To calculate flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on ‘standard’ conditions, which means that they reflect the cost of 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*

Local Tariffs*

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.

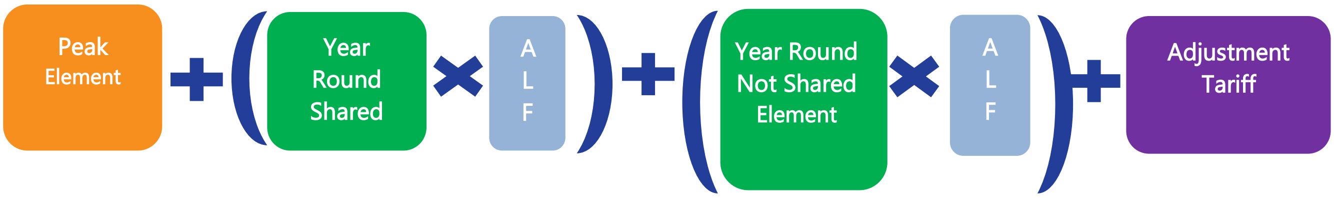
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

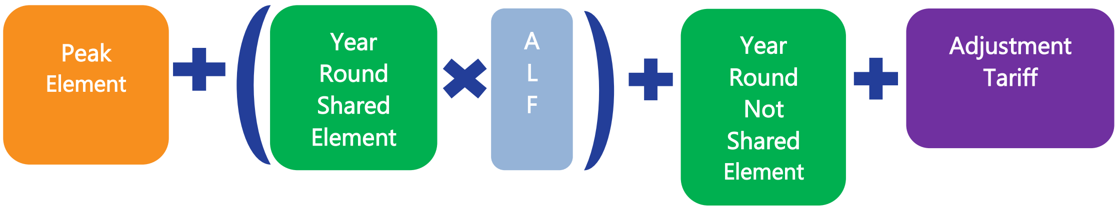
Conventional Carbon Generators

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



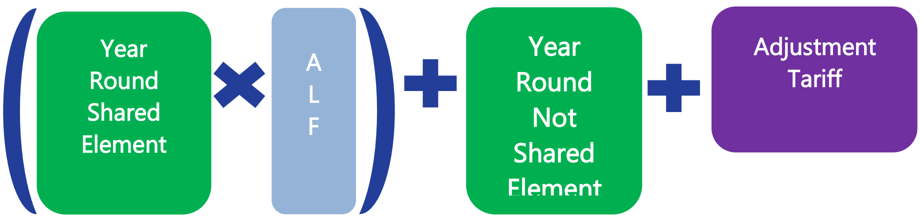
Conventional Low Carbon Generators

(e.g. Hydro, Nuclear)



Intermittent Generators

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



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

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

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

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

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

Local substation tariffs

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

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

Local circuit tariffs

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

Embedded network system charges

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

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

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

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

The calculation for TNUoS generator monthly liability is as follows:

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

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

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

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.

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

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

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers have two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff. With the implementation of CMP343, the demand residual element of the demand charges are to be split out (previously included in the HH and NHH locational charges) and an additional set off banded charges are to apply to HH and NHH demand.

HH gross demand tariffs

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

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

Embedded Export Tariffs (EET)

The EET was introduced under CMP264/265 and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

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

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

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

Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by the ESO. Payments for embedded exports from SVA registered embedded generators will be paid to their registered supplier.

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

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

15 https://www.nationalgrideso.com/charging/charging-guidance

Note: HH demand and embedded export is charged at the GSP group, where the transmission network connects to the distribution network, or directly to the customer in question.

NHH demand tariffs

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

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

Demand residual banded charges

With recent decision made by Ofgem for CMP343 the new demand residual banded charging methodology is to be implemented from April 2023. The demand residual banded charges will now make up majority of the TNUoS demand charge in the form of a set of daily charge per site across the banding categories and thresholds.

Appendix B: Changes and proposed changes to the charging methodology

ESO

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.	
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

ESO

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 August		2023/24 November		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.035381	-30.818022	-1.906568	-30.866286	0.128813	-0.048263
2	Southern Scotland	-2.439368	-22.069355	-1.707542	-20.143326	0.731825	1.926029
3	Northern	-3.544673	-10.225715	-3.410276	-8.758459	0.134397	1.467255
4	North West	-1.127355	-5.593885	-0.526905	-3.819108	0.600450	1.774777
5	Yorkshire	-2.496096	-3.854227	-2.282958	-2.246485	0.213138	1.607742
6	N Wales & Mersey	-2.018190	-2.605353	-1.120566	-1.016459	0.897624	1.588894
7	East Midlands	-2.495909	0.767854	-2.022679	1.527219	0.473230	0.759364
8	Midlands	-1.754297	1.719734	-0.636106	3.682999	1.118191	1.963265
9	Eastern	1.002243	-0.069206	1.052036	-0.779521	0.049793	-0.710316
10	South Wales	-4.581861	7.075267	-2.601437	9.291238	1.980424	2.215971
11	South East	3.177970	0.342860	3.083559	-0.155030	-0.094412	-0.497890
12	London	5.429676	1.716242	4.269965	0.104577	-1.159711	-1.611665
13	Southern	1.463798	4.248810	1.462256	3.828359	-0.001542	-0.420451
14	South Western	0.691449	6.807923	0.893521	6.752186	0.202073	-0.055738

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

Demand Zone		2023/24 August		2023/24 November		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-32.853403	2.540292	-32.772853	2.547308	0.080550	0.007016
2	Southern Scotland	-24.508722	2.540292	-21.850868	2.547308	2.657854	0.007016
3	Northern	-13.770387	2.540292	-12.168735	2.547308	1.601652	0.007016
4	North West	-6.721240	2.540292	-4.346013	2.547308	2.375227	0.007016
5	Yorkshire	-6.350323	2.540292	-4.529443	2.547308	1.820880	0.007016
6	N Wales & Mersey	-4.623543	2.540292	-2.137025	2.547308	2.486518	0.007016
7	East Midlands	-1.728055	2.540292	-0.495461	2.547308	1.232594	0.007016
8	Midlands	-0.034563	2.540292	3.046892	2.547308	3.081455	0.007016
9	Eastern	0.933038	2.540292	0.272515	2.547308	-0.660523	0.007016
10	South Wales	2.493406	2.540292	6.689801	2.547308	4.196395	0.007016
11	South East	3.520830	2.540292	2.928529	2.547308	-0.592301	0.007016
12	London	7.145918	2.540292	4.374542	2.547308	-2.771376	0.007016
13	Southern	5.712609	2.540292	5.290615	2.547308	-0.421994	0.007016
14	South Western	7.499372	2.540292	7.645707	2.547308	0.146335	0.007016

Appendix D: Annual Load Factors

ESO

ALFs

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

For the purposes of this forecast, we have used the draft version of the 2023/24 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2017/18 to 2021/22. Generators which commissioned after 1 April 2019 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 2023/24 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 have been updated with the recently released Draft ALFs. These are available for industry consultation until Wednesday 21st December, after which they will become final. It is feasible that the ALFs may therefore change ahead of the January Final tariffs following this consultation period. The specific and generic draft ALFs for 2023/24 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
Battery	1.2391%
Biomass	43.9150%
CCGT_CHP	49.3613%
Coal	17.6627%
Gas_Oil	0.4762%
Hydro	41.6409%
Nuclear	68.2026%
Offshore_Wind	46.9350%
Onshore_Wind	39.4259%
Pumped_Storage	8.5995%
Reactive_Compensation	0.0000%
Solar	10.9000%
Tidal	11.6000%
Wave	2.9000%

Please 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

ESO

The contracted TEC volumes are used to set locational tariffs; however, we also 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 is now 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 August forecast using data from the October 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
Abergelli Power Limited	-299	SWAN20_SPM	21
Crystal Rig IV Wind Farm	-48.2	CRYR40	11
Harestanes	-38	HARE10	12
Hornsea Power Station 2A	440	KILL40	15
Hornsea Power Station 2B	440	KILL40	15
Hornsea Power Station 2C	440	KILL40	15
JG Pears	-40	HIGM40	16
Shoreham	40	BOLN40	25
Tees CCPP	150	GRSA20	13

Please note: The increases listed for Hornsea Power Stations 2A, 2B, 2C and Shoreham are not actually increases to the contracted TEC, these are included because of a reporting error in our previous forecasts, which meant that they were already included in our best view but not the contracted position (this means that the values used in the tariff setting for these stations was correct since the previous forecasts were based on the best view). This has now been amended in our process.

Appendix F: Transmission company revenues

ESO

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have updated us with their revenue forecast for year 2022/23, and the revenue forecasts will be updated again in January 2022. In addition, there are some pass-through items that are to be collected by ESO via TNUoS charges, including the Strategic Innovation Fund (SIF), contribution made from IFA, and site-specific adjustments by TOs etc.

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

Notes:

All monies are quoted in millions of pounds, accurate to two decimal 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. ESO and TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither ESO nor TOs accept or assume responsibility for the use of this information by any person or any person to whom this information is shown or any person to whom this information otherwise becomes available.

ESO TNUoS revenue pass-through items forecasts

From April 2019, a new, legally separate electricity system operator (ESO) 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 ESO and passed through to NGET, in the same way to the arrangement with Scottish TOs and OFTOs.

In addition, ESO 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 ESO. The revenue breakdown table below shows details of the pass-through TNUoS revenue items under ESO's licence conditions.

Since our August forecast, it can be observed that there is a have changed (see table 25) with the most notable variations being seen with a reduction in Interconnector cost recovery (ICPt -£15.84m) in comparison to the last update for forecast (this value was previously added in as a ICFt value therefore isn't really a reduction but the same value reported in August albeit in a different category), the Adjustment Factor (-£4.2m as actuals replaces forecast data),

Table 28 ESO revenue breakdown

Term	ESO TNUoS Other Pass-Through		
	August Forecast	November Draft	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)	9.90	10.94	1.05
The Adjustment Term (ADJt)	-29.02	-33.23	-4.20
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	751.15	616.17	-134.98
Interconnectors CACM Cost Recovery (ICPt)	0.00	-15.84	-15.84
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)*	2,097.34	2,141.27	43.93
SPT revenue pass-through (TSPt)	443.60	498.24	54.64
SHETL revenue pass-through (TSHt)	750.18	711.93	-38.26
ESO Bad debt (BDt)	3.60	3.93	0.33
ESO other pass-through items (LFt + ITCt etc)	40.33	36.47	-3.86
ESO legacy adjustment (LARt)	0.00	0.00	0.00
Total	**4,080.62**	**3,983.43**	**-97.18**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have provided us with their revenue breakdown and will next update them in January 2023.The current forecasts include updates in correction term data, refreshed forecasts of interest rates. The data is liable to change as interest rate parameters are updated. The allowed revenue figures will be finalised in the January 2023 submission by TOs, and will incorporate any potential upward and downward changes.

Offshore Transmission Owner revenue

The Offshore Transmission Owner revenue to be collected via TNUoS for 2023/24 is forecast to be £746.3m, an increase of £10.98m from the August forecast. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to the latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

Interconnector adjustment

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.

Ofgem has approved an offer from National Grid Venture (NGV) to make early payments of £200 million to consumers over the next two years[16], as part of the cap and floor regulatory regime for electricity interconnectors. This enables Interconnectors, under cap & floor arrangements, to make payments of above

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

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 forecast £130m of early cap & floor within payment adjustment for 2023/24, the values for 2023/24 payment will be confirmed in our Final Tariffs.

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	283.31	
Inflation		PI_t	324.73	341.97	341.97	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	1,737.57	1,737.57	1,788.82	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	37.19	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**1,991.59**	**2,097.34**	**2,196.40**	
SONIA	B1	It-1	1.15%	1.15%	4.78%	
Allowed Revenue	B2	ARt-1	1,795.07	1,795.07	1,761.36	
Recovered Revenue	B4	RRt-1	1,795.07	1,795.07	1,761.36	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**0.00**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	-53.19	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	-1.59	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**0.00**	**0.00**	**-54.78**	
Site Rental Charges			**0.00**	**0.00**	**0.35**	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**1,991.59**	**2,097.34**	**2,141.27**	

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	283.31	
Inflation		PI_t	324.73	341.97	349.31	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	367.50	367.50	378.38	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	19.18	
[$ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t$]	**A**	**$ADJR_t$**	**421.23**	**443.60**	**485.71**	
SONIA	B1	It-1	1.15%	1.15%	4.78%	
Allowed Revenue	B2	ARt-1	0.00	0.00	357.62	
Recovered Revenue	B4	RRt-1	0.00	0.00	336.15	
Correction Term [$K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)$]	**B**	**K_t**	**0.00**	**0.00**	**22.75**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	-11.57	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	1.25	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.09	
Legacy Adjustment [$LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t$]	**C**	**LAR_t**	**0.00**	**0.00**	**-10.22**	
Site Rental Charges						
Total Allowed Revenue [$AR_t = ADJR_t + K_t + LAR_t$]	**D**	**AR_t**	**421.23**	**443.60**	**498.24**	

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	283.31	
Inflation		PI_t	324.73	341.97	341.97	
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	621.50	621.50	602.22	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	0.00	0.00	-22.43	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	**A**	**$ADJR_t$**	**712.36**	**750.18**	**704.48**	
SONIA	B1	It-1	1.15%	1.15%	4.78%	
Allowed Revenue	B2	ARt-1	673.24	673.24	662.40	
Recovered Revenue	B4	RRt-1	673.24	673.24	670.92	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	**B**	**K_t**	**0.00**	**0.00**	**-9.03**	
Legacy pass-through	C1	LPt	0.00	0.00	0.00	
Legacy MOD	C2	LMODt	0.00	0.00	16.47	
Legacy K correction	C3	LKt	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	0.00	0.00	0.00	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	0.00	0.00	0.00	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incentive	C7	LSFIt	0.00	0.00	0.00	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	0.00	0.00	0.00	
Close out of RIIO-1 Network Outputs	C9	NOCOt	0.00	0.00	0.00	
Legacy Adjustment $[LAR_t = LPT_t + LMOD_t + LK_t + LTRU_t + NOCO_t + LSSO_t + LEDR_t + LSFI_t + LRI_t]$	**C**	**LAR_t**	**0.00**	**0.00**	**16.47**	
Site Rental Charges						
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	**D**	**AR_t**	**712.36**	**750.18**	**711.93**	

Table 32 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	Year										
Regulatory 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	9.7	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	15.6	17.7	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	9.8	10.9	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	16.3	18.2	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	24.2	26.7	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	36.9	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	46.8	52.4	Current revenues plus indexation
Thanet	78.9	17.4	15.7	19.5	18.6	19.2	19.7	20.8	21.6	24.0	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	32.5	34.0	Current revenues plus indexation
Gwynt y mor		25.3	23.6	29.3	32.7	34.0	18.9	32.9	39.8	37.0	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	25.5	28.3	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	13.3	15.1	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	14.7	16.5	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	14.7	16.5	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	20.8	22.6	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	28.9	32.4	Current revenues plus indexation
Galloper							16.1	17.1	17.8	20.0	Current revenues plus indexation
Walney 3							28.8	13.5	14.1	15.9	Current revenues plus indexation
Walney 4								13.5	14.1	15.9	Current revenues plus indexation
Hornsea 1A								137.1	18.4	20.6	Current revenues plus indexation
Hornsea 1B									18.4	20.6	Current revenues plus indexation
Hornsea 1C									18.4	20.6	Current revenues plus indexation
Beatrice									21.1	24.2	Current revenues plus indexation
Rampion									15.5	17.3	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2022/23									68.3	64.4	National Grid Forecast
Forecast to asset transfer to OFTO in 2023/24										104.0	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	746.3	

Notes:

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

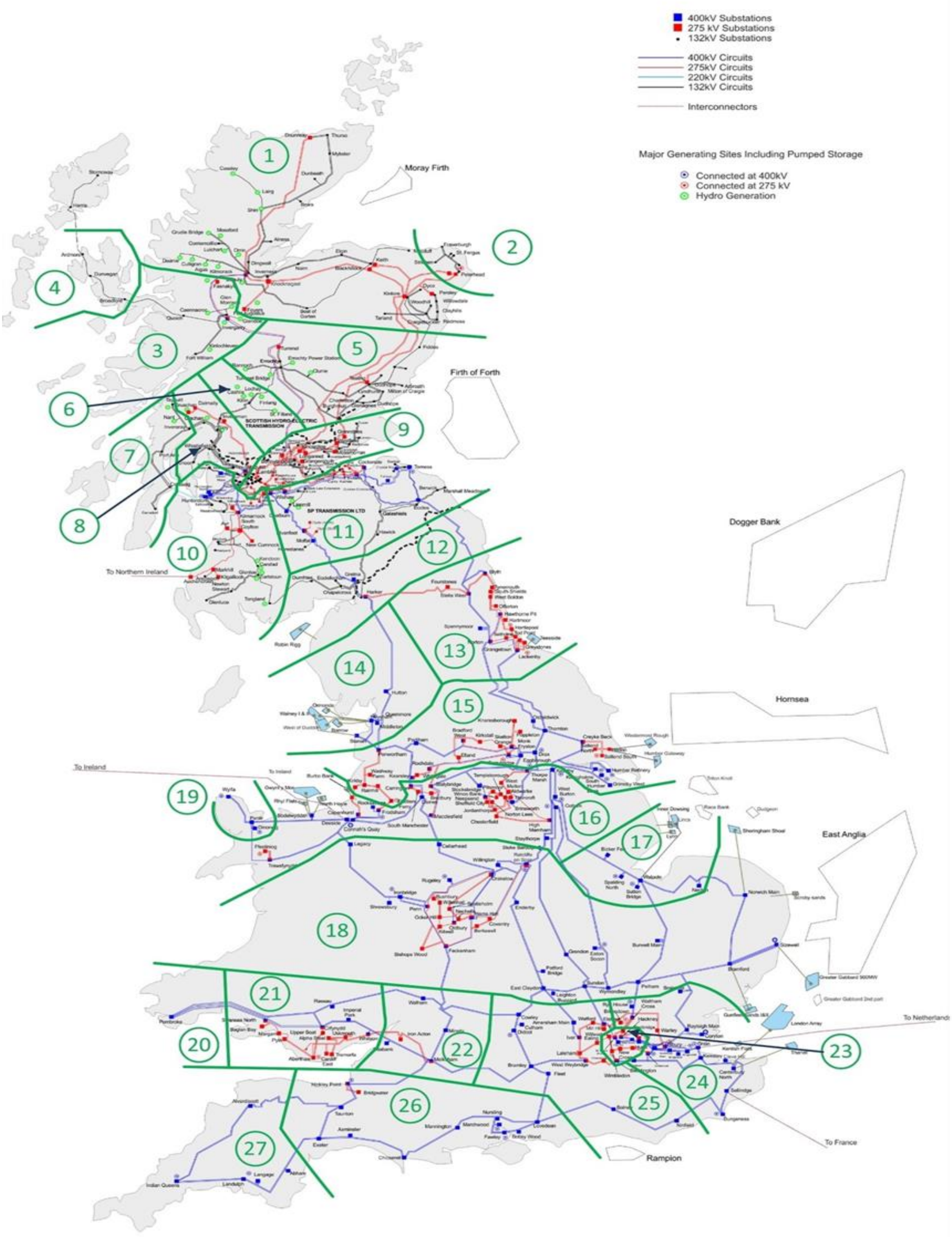
Licensee forecasts and budgets are subject to change especially where they are influenced by external stakeholders

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

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

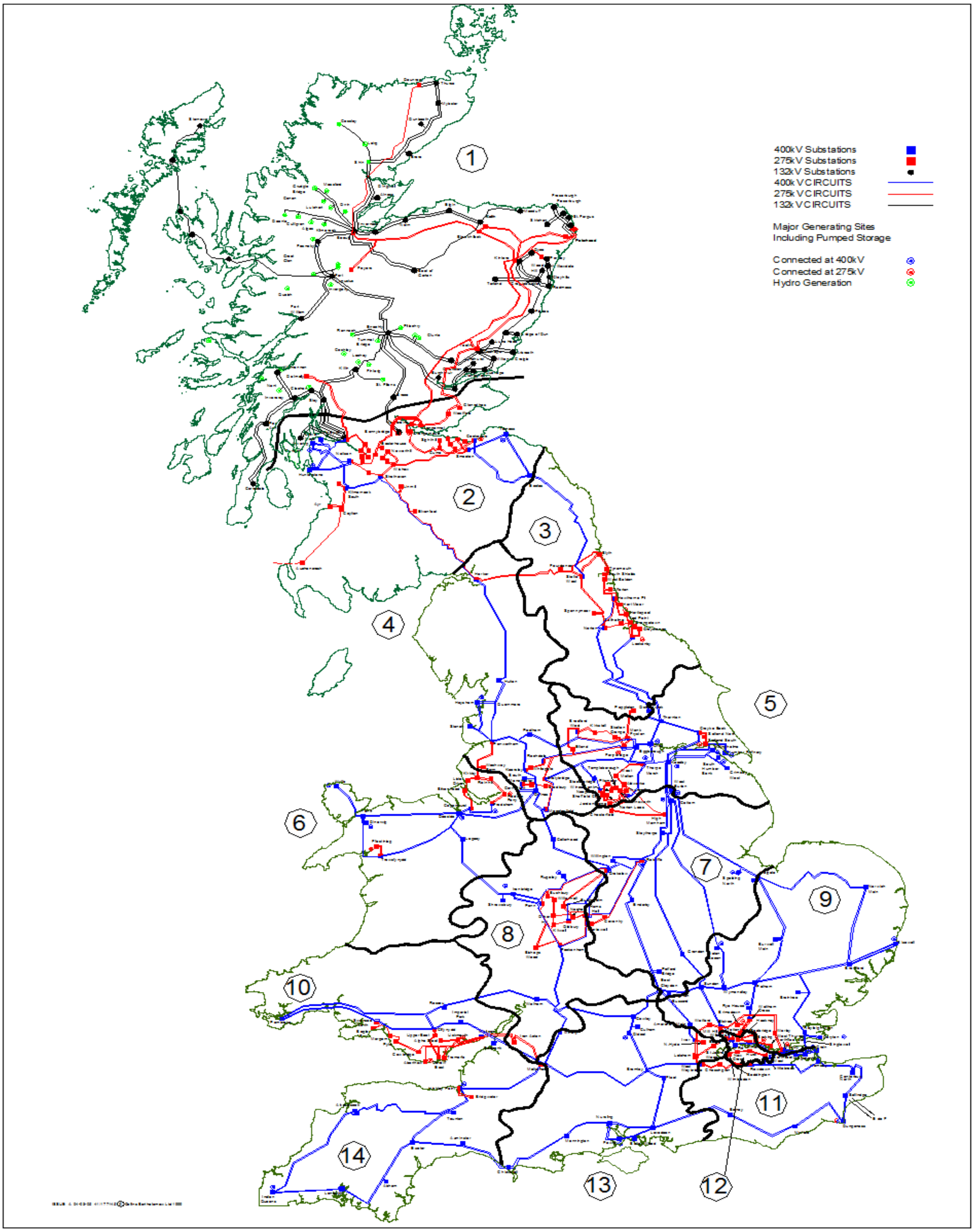
Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



For the most up to date maps, please refer to [ETYS 2021 AppA _ diagrams]

Appendix H: Demand zones map


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

Appendix I: Changes to TNUoS parameters

ESO

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

<table>
<tr><th colspan="6">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">August 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">August update using previous year's data source (except local circuit changes which are updated quarterly)</td><td>Latest version based on ETYS</td><td></td></tr>
<tr><td>Inflation</td><td colspan="3">forecast</td><td>Actual</td></tr>
<tr><td rowspan="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>August 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>August 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>

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

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