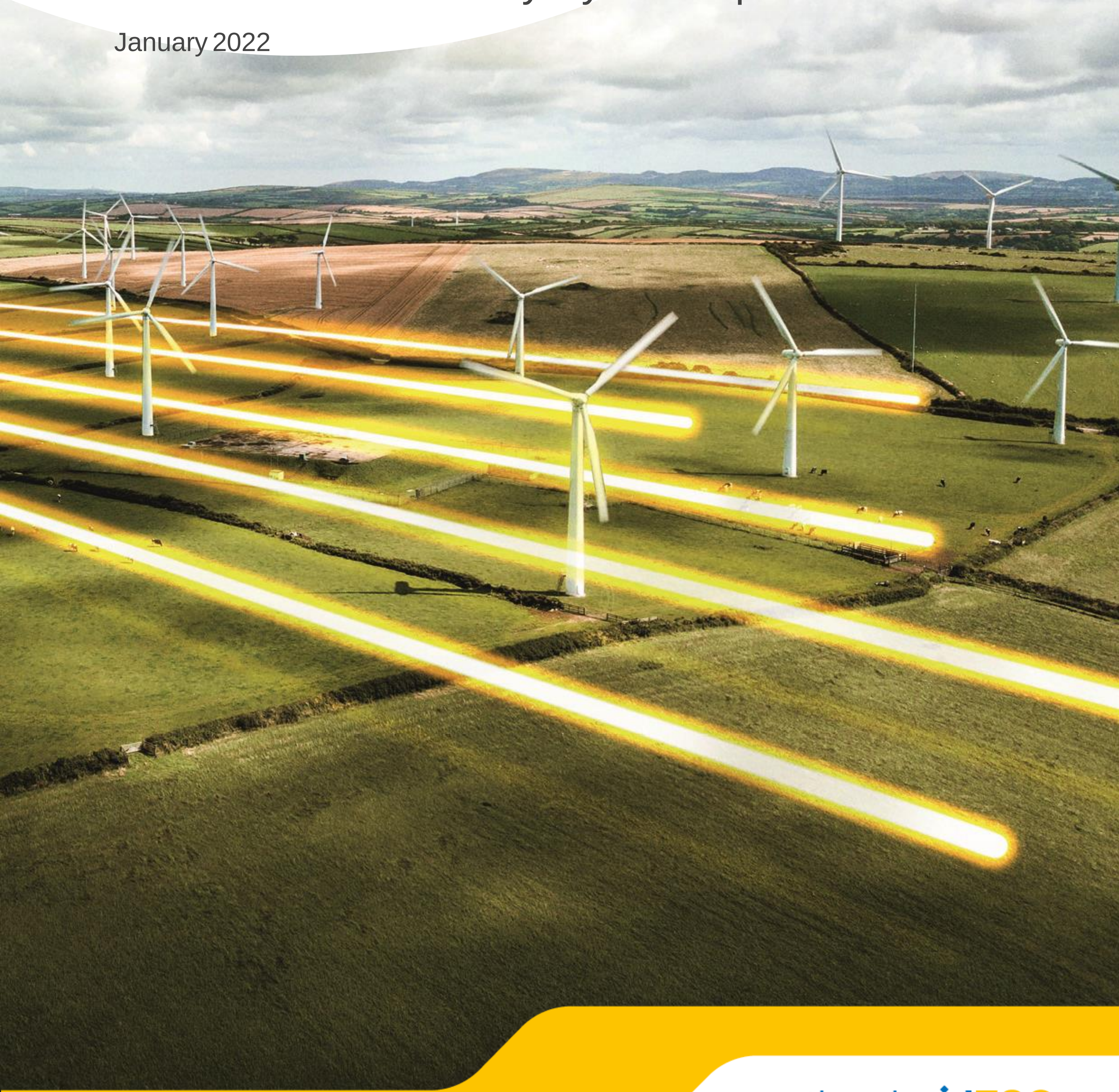
Final TNUoS Tariffs for 2022/23

National Grid Electricity System Operator

January 2022



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Executive summary

Transmission Network Use of System (TNUoS) charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Final TNUoS Tariffs for 2022/23.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish the Final Transmission Network Use of System (TNUoS) tariffs for year 2022/23 on our website[1].

These tariffs will take effect from 1st April 2022, they have no impact on charging year 2021/22.

Regulatory Uncertainty – CMP317/327

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

As CMP317/327 decision is being legally challenged, there is a potential risk that the 2022/23 tariffs may need to be re-calculated under revised methodology, as a result of the JR outcome and/or any relevant Ofgem decisions. Once the JR outcome is known, we will confirm if changes to the 2022/23 tariffs are required as soon as possible.

In addition to CMP317/327, the ESO raised CMP368/369 in 2021, to fully align the CUSC methodology with Ofgem's interpretation of the Limiting Regulation. The changes were proposed to be implemented for 2022/23[2], and thus our previous quarterly forecasts have included the original proposal under CMP368/369. Due to the ongoing JR, Ofgem have not made a decision on CMP368/369 which is dependent on CMP317/327 outcome[3]. Therefore, in this report, our final tariffs reflect the currently approved CUSC modifications in the methodology, and therefore include CMP317/327 impacts, but do not include CMP368/369 impacts.

Transmission Demand Residual (TDR)

The implementation of the TDR banded charges methodology is not expected until charging year 2023/24 (as per Ofgem's latest minded to position for CMP343[4]) and has not been included in Final tariffs for 2022/23. The 5-Year View published April 2021 shows the potential impact that TDR banding will have on forecast demand tariffs from 2023/24 which can be found on our website[5]. Currently we are expecting that our next 5-Year forecast (2023/24 to 2027/28) and following 2023/24 TNUoS tariff setting forecast, Draft and Final publications will include the impact of the TDR methodology changes. Further clarification and guidance for the potential change in methodology and impact on tariffs are to be included in these.

Total revenues to be recovered

The total TNUoS revenue to be collected is £3,594m, based on the final onshore TO and OFTO revenue submissions. This is an increase compared to the total TNUoS revenue in 2021/22 but a decrease of £10m from the November Draft forecast.

Generation tariffs

The total revenue to be recovered from generators is forecast at £842.0m for 2022/23, an increase of £25.4m from the Draft tariffs. Mainly driven by the increase in revenue from offshore local tariffs.

1 https://www.nationalgrideso.com/industry-information/charging/transmission-network-use-system-tnuos-charges
2 https://www.ofgem.gov.uk/publications/cmp317-cmp327-excluding-assets-required-connection-and-removing-transmission-generator-residual
3 https://www.nationalgrideso.com/document/222786/download
4 https://www.ofgem.gov.uk/sites/default/files/docs/2021/05/cmp343_minded-to_decision_consultation.pdf
5 https://www.nationalgrideso.com/document/191116/download

The generation charging base has been updated to 72.4GW based on our best view on generation projects for 2022/23. This is a decrease of 0.1GW since the Draft tariffs[6]. The average generation tariff is £11.62/kW, an increase of £0.36/kW due to the increase in generation revenue.

Demand tariffs

Revenue to be collected through demand is forecast at £2,752m for 2022/23. This value has reduced by £35m compared to the Draft tariffs. The main driver is the reduction in revenue to be collected in total through TNUoS.

The impact on the end consumer is forecast to be £38.14 per household in 2022/23, a decrease of £0.95 from Draft tariffs. This is due to the decrease in the total demand revenue.

In 2022/23 it is forecast that £15.6m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), an increase of £1.3m since the Draft tariff forecast. This is due to the increase in the forecast charging base for Embedded Export. The average EET is forecast at £2.08/kW, which is an increase of £0.13/kW versus Draft tariffs.

The average gross HH demand tariff for 2022/23 is to be £55.06/kW, a decrease of £0.65/kW and the average NHH demand tariff forecast is at 6.81p/kWh, a decrease of 0.17p/kWh since Draft tariffs.

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts for 2023/24 is available on our website[7].

Our next TNUoS tariff publication will be our initial forecast of 2023/24 tariffs and the 5 Year View of TNUoS tariffs, which will be published in March 2022.

Feedback

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

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

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

[6] Value incorrectly reported as 72.9GW in Draft tariff report, correct value was 72.5GW

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

Charging Methodology Changes

nationalgridESO

This Report

This report contains the Final TNUoS tariffs for the charging year 2022/23.

The TNUoS tariff setting methodology defined in the CUSC is subject to open governance. We are obliged to comply with the latest approved CUSC changes applicable from 1st April 2022 in the Final Tariffs for 2022/23. This section summarises any key changes to the methodology.

Charging methodology changes

There have been no changes that have been approved to the charging methodology since January 2021, when we published the Final 2021/22 tariffs.

In our previous quarterly forecasts for 2022/23 tariffs, we have included the impacts of CMP368/369. This CUSC mod (CMP368/369) was raised by the ESO to exclude certain elements in generation local charges from the gen cap calculation, and to also exclude generation volume and charges associated with TNUoS-liable embedded generators from the gen cap.

As CMP368/369 is not approved yet, we have removed CMP368/369 from the Final tariff calculation. This has shifted part of the demand charges to generation users (by £10.8m), as the net effect of CMP368/369 would have reduced the gen cap by £10.8m.

Regulatory Uncertainty

Following the Targeted Charging Review (TCR), CUSC modification proposals (CMP317/327) were raised and were approved in December 2020. Please note that leave has been granted for a judicial review (JR) of the Competition and Markets Authority (CMA) decision, on the appeal to the CMA of the Ofgem's 2020 CMP317/327 decision, and the proceedings are yet to be concluded. As CMP317/327 decision is being legally challenged, there is a potential risk that the 2022/23 tariffs may need to be re-calculated under a revised methodology, as a result of the JR outcome and/or any relevant Ofgem decisions. Once the JR outcome is known, we will confirm if changes to the 2022/23 tariffs are required as soon as possible.

In addition to CMP317/327, the ESO raised CMP368/369 in 2021, to fully align the CUSC methodology with Ofgem's interpretation of the Limiting Regulation. The changes were proposed to be implemented for 2022/23, and thus our previous quarterly forecasts have included the original proposal under CMP368/369. Due to the ongoing JR, Ofgem have not made a decision on CMP368/369 which is dependent on CMP317/327 outcome[8]. Therefore, in this report, our final tariffs reflect the currently approved CUSC modifications in the methodology, and therefore include CMP317/327 impacts[9] but do not include CMP368/369 impacts.

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. Along with the low levels of demand, there was a shift in HH and NHH consumptions, both of which created increased uncertainty in the demand forecast that feeds into TNUoS demand tariffs. As mentioned in previous forecasts, our view was that whilst it is anticipated that the impact of COVID-19 on demand will continue into 2021/22 there will be a steady shift towards 'normal' demand levels as the year progresses, but 'economic scarring' will still be present.

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[8] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp368-cmp369

[9] The CMP317/327 impacts under the original proposal, and various WACMs, can be found in the Final Modification Report (FMR) here https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp317-cmp327

Analysing current year (2021/22) outturn data for demand, this shift can be seen. HH demand has increased and whist NHH has fluctuated over winter we are seeing an overall reduction in NHH demand (in-line with what was forecast in tariffs for 2021/22).

In the Final tariff forecast, the same approach/assumptions due to COVID-19 are applied for 2022/23, the return to ‘normal’ can be 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, although slightly higher than what was forecast in the Draft tariffs.

Generation tariffs

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

1. Generation tariffs summary

This section summarises our view of generation tariffs for 2022/23 and how these tariffs were calculated.

This forecast includes the implementation of the TGR via CMP317/327, which took effect from April 2021 i.e. all local onshore and local offshore tariffs are not included in the € [0 ~ 2.50]/MWh range for generator transmission charge Limiting Regulation, in line with the final decision on CMP317/327.

When approving CMP317/327, Ofgem also directed the ESO to raise CMP368/369. As the final decision on CMP368/389 has not been made yet, we have removed calculation of the pre-existing local asset charges (the calculation was undertaken in previous forecasts under the CMP368/369 original proposal). We have re-applied the wider charges associated with TNUoS-liable embedded generators in the total generation charge and re-applied expected generation outputs from those chargeable embedded generators in the 2022/23 Final tariffs. Thus reversing the impact of CMP368/389 from 2022/23 tariffs (of which was included in previous publications for 2022/23)

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2022/23 Draft	2022/23 Final	Change since last forecast
Adjustment	- 0.292593	- 0.228726	0.063867
Average Generation Tariff*	11.258529	11.622336	0.363807

*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 Commission Regulation (EU) 838/2010, which has been adopted in UK legislation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. The adjustment tariff is currently negative to ensure Generation Tariffs are compliant with the legislation. The implementation of CMP317/327 means that charges for local onshore and offshore tariffs are not included in the €2.50/MWh cap.

Average generation tariffs have increased by £0.36/kW, due to an increase of £25.4m in the revenue to be collected from generation. The generation adjustment has increased by £0.06/kW to become slightly less negative. This is due to the wider tariff decreasing, meaning there is less of a requirement to decrease the overall generation tariff to ensure compliance with the €2.50/MWh cap.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2022/23. A brief description of generation wider tariff structure can be found in Appendix A.

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

The classifications of generator type are listed below:

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass	Nuclear	Offshore wind
CCGT/CHP	Hydro	Onshore wind
Coal		Solar PV
OCGT/Oil		Tidal
Pumped storage (including battery storage)		

Each forecast, we publish example tariffs for a generator of each technology type using an example ALF. In previous forecasts we have used example ALFs as - Conventional Carbon 80%, Conventional Low Carbon 80% and Intermittent 40%. Prior to our August forecast, we reviewed the example ALFs we use for each fuel type to reflect the changing industry landscape and align to the ALFs we would expect to see based on the generic and specific ALFs we publish and use for charging. The ALFs we have used in this forecast are:

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

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

Table 2 Generation wider tariffs

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 40%	Conventional Low Carbon 75%	Intermittent 45%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	4.037870	18.772316	17.540622	-0.228726	18.334319	35.429003	25.759438
2	East Aberdeenshire	3.412809	9.105333	17.540622	-0.228726	13.842465	27.553705	21.409296
3	Western Highlands	3.762459	16.715407	16.666088	-0.228726	16.886331	32.736376	23.959295
4	Skye and Lochalsh	-0.801547	16.715407	18.241941	-0.228726	12.952666	29.748223	25.535148
5	Eastern Grampian and Tayside	4.718927	12.133958	13.860260	-0.228726	14.887888	27.450930	19.091815
6	Central Grampian	4.075139	12.559466	14.354827	-0.228726	14.612130	27.620840	19.777861
7	Argyll	2.457357	10.648546	19.907501	-0.228726	14.451050	30.122542	24.470621
8	The Trossachs	3.390150	10.648546	12.092775	-0.228726	12.257952	23.240609	16.655895
9	Stirlingshire and Fife	2.840483	10.103492	11.622964	-0.228726	11.302339	21.812340	15.940809
10	South West Scotlands	2.384017	9.923382	11.482148	-0.228726	10.717503	21.079976	15.718944
11	Lothian and Borders	4.651799	9.923382	6.884609	-0.228726	11.146269	18.750219	11.121405
12	Solway and Cheviot	2.413107	6.709728	6.503989	-0.228726	7.469868	13.720666	9.294641
13	North East England	4.707139	5.364557	4.300728	-0.228726	8.344527	12.802559	6.486053
14	North Lancashire and The Lakes	1.894399	5.364557	1.377186	-0.228726	4.362370	7.066277	3.562511
15	South Lancashire, Yorkshire and Humber	5.246656	1.791232	0.223035	-0.228726	5.823637	6.584389	0.800363
16	North Midlands and North Wales	3.949239	0.751514	-	-0.228726	4.021119	4.284149	0.109455
17	South Lincolnshire and North Norfolk	4.010018	-0.419162	-	-0.228726	3.613627	3.466921	-0.417349
18	Mid Wales and The Midlands	1.574188	1.275666	-	-0.228726	1.855728	2.302212	0.345324
19	Anglesey and Snowdon	4.836354	1.308885	-	-0.228726	5.131182	5.589292	0.360272
20	Pembrokeshire	7.438941	-4.614656	-	-0.228726	5.364353	3.749223	-2.305321
21	South Wales & Gloucester	3.285553	-5.364926	-	-0.228726	0.910857	-0.966867	-2.642943
22	Cotswold	1.971701	3.080800	-6.994646	-0.228726	0.177437	-2.941071	-5.837012
23	Central London	-2.666852	3.080800	-9.826937	-0.228726	-5.594033	-10.411915	-8.669303
24	Essex and Kent	-2.943894	3.080800	-	-0.228726	-1.940300	-0.862020	1.157634
25	Oxfordshire, Surrey and Sussex	-1.735486	-0.858400	-	-0.228726	-2.307572	-2.608012	-0.615006
26	Somerset and Wessex	-3.443002	-2.134847	-	-0.228726	-4.525667	-5.272863	-1.189407
27	West Devon and Cornwall	-2.104777	-4.734711	-	-0.228726	-4.227387	-5.884536	-2.359346

3. Changes to wider tariffs since the Draft generation tariffs forecast

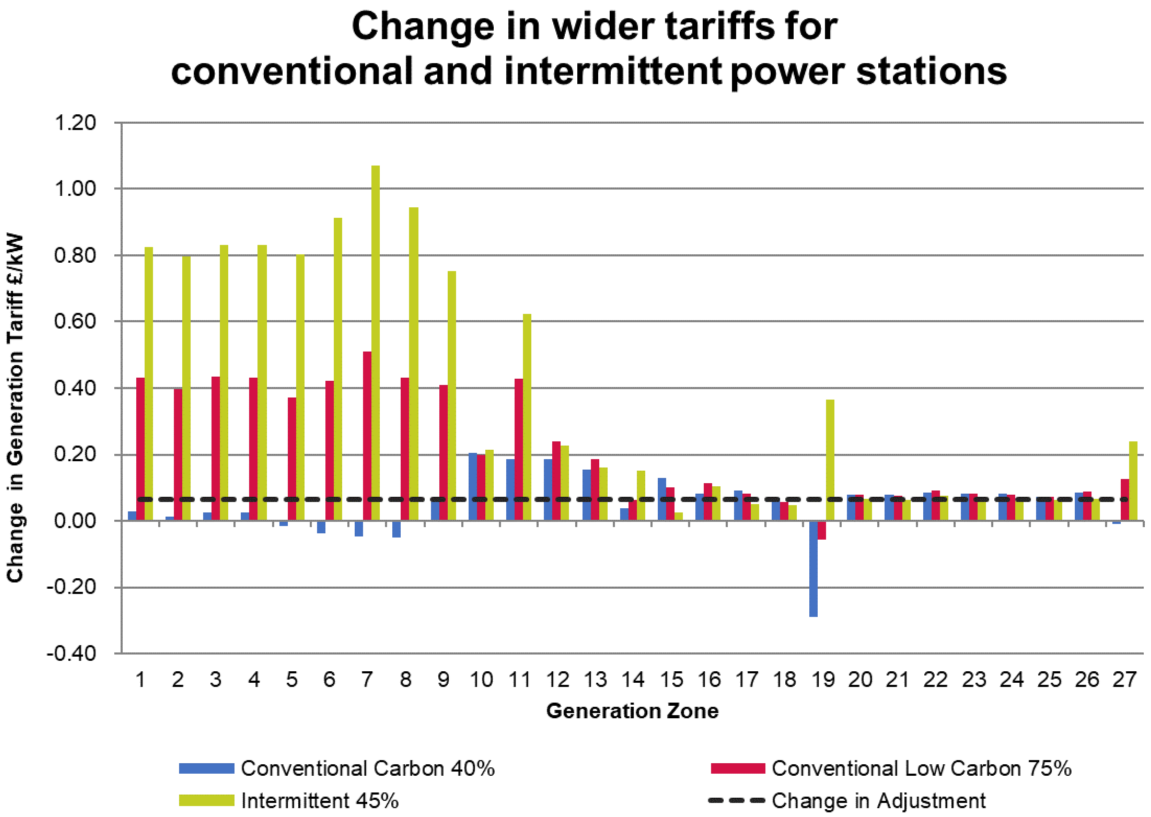
The following section provides details of the wider generation tariffs for 2022/23 and explains how these have changed since the August forecast. We have compared the example tariffs for Conventional Carbon generators with an ALF of 40%, Conventional Low Carbon generators with an ALF of 75%, and Intermittent generators with an ALF of 45% for illustration purposes only

The Generation tariffs in the below tables include the implementation of the TCR, where the generation residual has increased and become less negative due to the exclusion of the local tariffs from the €2.50/MWh cap.

Table 3 Generation wider tariff changes

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 40%			Conventional Low Carbon 75%			Intermittent 45%			
Zone	Zone Name	2022/23 Draft	2022/23 Final	Change	2022/23 Draft	2022/23 Final	Change	2022/23 Draft	2022/23 Final	Change	Change in Adjustment
1	North Scotland	18.306612	18.334319	0.027707	34.998340	35.429003	0.430663	24.934755	25.759438	0.824683	0.063867
2	East Aberdeenshire	13.828864	13.842465	0.013601	27.158334	27.553705	0.395371	20.611850	21.409296	0.797445	0.063867
3	Western Highlands	16.860221	16.886331	0.026110	32.302269	32.736376	0.434107	23.127319	23.959295	0.831976	0.063867
4	Skye and Lochalsh	12.927624	12.952666	0.025042	29.316014	29.748223	0.432209	24.704556	25.535148	0.830592	0.063867
5	Eastern Grampian and Tayside	14.904446	14.887888	-0.016558	27.078670	27.450930	0.372260	18.288242	19.091815	0.803573	0.063867
6	Central Grampian	14.649953	14.612130	-0.037822	27.198480	27.620840	0.422360	18.864431	19.777861	0.913430	0.063867
7	Argyll	14.497967	14.451050	-0.046918	29.613473	30.122542	0.509068	23.400141	24.470621	1.070479	0.063867
8	The Trossachs	12.307989	12.257952	-0.050037	22.809601	23.240609	0.431007	15.710318	16.655895	0.945576	0.063867
9	Stirlingshire and Fife	11.246617	11.302339	0.055723	21.403123	21.812340	0.409217	15.188204	15.940809	0.752605	0.063867
10	South West Scotlands	10.512852	10.717503	0.204651	20.880190	21.079976	0.199786	15.505271	15.718944	0.213673	0.063867
11	Lothian and Borders	10.959964	11.146269	0.186305	18.322356	18.750219	0.427863	10.497027	11.121405	0.624378	0.063867
12	Solway and Cheviot	7.282814	7.469868	0.187054	13.479935	13.720666	0.240732	9.067027	9.294641	0.227614	0.063867
13	North East England	8.190796	8.344527	0.153731	12.617582	12.802559	0.184977	6.325237	6.486053	0.160816	0.063867
14	North Lancashire and The Lakes	4.325067	4.362370	0.037303	7.003044	7.066277	0.063233	3.410556	3.562511	0.151955	0.063867
15	South Lancashire, Yorkshire and Humber	5.693609	5.823637	0.130028	6.483600	6.584389	0.100789	0.775446	0.800363	0.024917	0.063867
16	North Midlands and North Wales	3.939291	4.021119	0.081828	4.170049	4.284149	0.114100	0.004096	0.109455	0.105359	0.063867
17	South Lincolnshire and North Norfolk	3.520589	3.613627	0.093039	3.384500	3.466921	0.082421	-0.467565	-0.417349	0.050216	0.063867
18	Mid Wales and The Midlands	1.786119	1.855728	0.069609	2.245519	2.302212	0.056692	0.298064	0.345324	0.047260	0.063867
19	Anglesey and Snowdon	5.421354	5.131182	-0.290172	5.645152	5.589292	-0.055860	-0.004852	0.360272	0.365124	0.063867
20	Pembrokeshire	5.285274	5.364353	0.079078	3.669007	3.749223	0.080216	-2.370651	-2.305321	0.065330	0.063867
21	South Wales & Gloucester	0.832358	0.910857	0.078498	-1.043855	-0.966867	0.076987	-2.704867	-2.642943	0.061924	0.063867
22	Cotswold	0.092576	0.177437	0.084861	-3.031964	-2.941071	0.090892	-5.911852	-5.837012	0.074840	0.063867
23	Central London	-5.677622	-5.594033	0.083589	-10.492451	-10.411915	0.080536	-8.729001	-8.669303	0.059698	0.063867
24	Essex and Kent	-2.021722	-1.940300	0.081422	-0.941027	-0.862020	0.079007	1.096873	1.157634	0.060761	0.063867
25	Oxfordshire, Surrey and Sussex	-2.380311	-2.307572	0.072739	-2.680501	-2.608012	0.072489	-0.678551	-0.615006	0.063545	0.063867
26	Somerset and Wessex	-4.610077	-4.525667	0.084410	-5.359742	-5.272863	0.086879	-1.256448	-1.189407	0.067041	0.063867
27	West Devon and Cornwall	-4.217546	-4.227387	-0.009841	-6.010096	-5.884536	0.125560	-2.597300	-2.359346	0.237954	0.063867

Figure 1 Variation in generation wider zonal tariffs



Locational changes

The locational tariffs have changed since the Draft tariffs due to an update in Contracted TEC. This change relates to an overstating of TEC for the Moyle (Auchencrosh) interconnector located in Gen zone 10.

This has meant that there have been changes in the overall tariffs across each generation zone. Using the example ALFs[10]*, Zone 10 and those zones surrounding it (Zone 11 – 13) have seen a slight increase in tariffs for all technology types and for Zones 1 – 9 & 11, Intermittent and Conventional Low Carbon have seen a noticeable increase. The remaining zones have seen marginal changes across each technology type, with the majority increasing slightly (in-line with the change in adjustment tariff), with some Zones (Zones 5 - 8) reducing slightly for convention carbon. It is worth highlighting that Zone 19 has seen a sizeable fluctuation in both directions depending on technology type.

Adjustment tariff changes

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

The adjustment tariff has increased marginally by £0.06/kW since Draft tariffs due to the removal of CMP368/389 and the change in the wider location charges. These changes cause the adjustment to go less negative as there is less adjustment require to ensure charges are within the gen cap. For a full breakdown of the generation revenues, please see Table 19.

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

Onshore local tariffs for generation

4. Onshore local substation tariffs

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

The CPIH figure used in the calculation of local substation tariffs has not changed and remains the same for Final tariffs as per Draft tariffs.

Table 4 Local substation tariffs

2022/23 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.150770	0.075388	0.051999
<1320 MW	Redundancy	0.317689	0.161359	0.114575
>=1320 MW	No redundancy	-	0.221489	0.157694
>=1320 MW	Redundancy	-	0.333303	0.239726

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 2022/23 Onshore local circuit tariffs are finalised, and are listed below in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberdeen Bay	2.671000	Edinbane	7.171952	Middleton	0.154278
Achruach	-2.616009	Ewe Hill	1.558191	Millennium South	0.494319
Aigas	0.685223	Fallago	-0.067330	Millennium Wind	1.720497
An Suidhe	-0.979390	Farr	3.652465	Mossford	2.951276
Arecleoch	2.176008	Fernoch	4.608469	Nant	-1.287043
Beinneun Wind Farm	1.380647	Ffestiniogg	0.259176	Necton	1.165832
Bhlaraidh Wind Farm	0.676448	Finlarig	0.335473	Rhigos	0.108099
Black Hill	1.590910	Foyers	0.300069	Rocksavage	0.018502
Black Law	1.830721	Glen Kyllachy	0.479246	Saltend	0.017775
Blackcraig Wind Farm	6.089148	Glendoe	1.927155	Sandy Knowe	5.244576
Blacklaw Extension	3.882282	Glenglass	4.929012	South Humber Bank	-0.190400
Clyde (North)	0.114898	Gordonbush	1.269706	Spalding	0.274973
Clyde (South)	0.132874	Griffin Wind	9.937450	Strathbrora	0.860658
Corriegarth	3.035227	Hadyard Hill	2.899919	Strathy Wind	2.029769
Corriemoillie	1.706045	Harestanes	2.448949	Stronelairg	1.114237
Coryton	0.047861	Hartlepool	0.091422	Wester Dod	0.356506
Creag Riabhach	3.514474	Invergarry	0.383397	Whitelee	0.111191
Cruachan	1.869753	Kilgallioch	1.102649	Whitelee Extension	0.309112
Culligran	1.815856	Kilmorack	0.206913		
Deanie	2.983193	Kype Muir	1.554002		
Dersalloch	2.523707	Langage	0.674171		
Dinorwig	2.457864	Lochay	0.383397		
Dorenell	2.149878	Luichart	0.589179		
Dumnaglass	1.187466	Marchwood	0.391622		
Dunhill	1.467292	Mark Hill	0.917330		
Dunlaw Extension	1.553756	Middle Muir	2.407415		

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 of cable	7.4km of OHL	Bhlaraidh
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 of Cable	3.9km of OHL	Aikengall II
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
East Kilbride South 275kV	Whitelee 275kV	6km of Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km of Cable	16.68km of OHL	Whitelee Extension
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of 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
Sandy Knowe 132kV	Glen Glass 132kV	7km of cable	7km of OHL	Sandy Knowe
Wishaw 132kV	Blacklaw 132kV	11.46km of 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 November, the forecast has been updated with the latest inflation indices.

Offshore local generation tariffs associated with projects due to transfer in 2021/22 or 2022/23 will be confirmed once asset transfer has taken place.

Table 7 Offshore local tariffs 2022/23

Offshore Generator	2022/23 Draft Tariff Component (£/kW)			2022/23 Final Tariff Component (£/kW)			Changes Tariff Component (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	9.152308	48.351171	1.200626	9.193620	48.569420	1.206045	0.041312	0.218249	0.005419
Beatrice	7.738282	21.105031	-	7.738282	21.105031	-	-	-	-
Burbo Bank	11.581837	22.384141	-	11.581837	22.384141	-	-	-	-
Dudgeon	16.940266	26.579538	-	16.940266	26.579538	-	-	-	-
Galloper	17.340653	27.426026	-	17.340653	27.426026	-	-	-	-
Greater Gabbard	17.050227	39.455940	-	17.129624	39.639672	-	0.079397	0.183732	-
Gunfleet	19.917368	18.367386	3.432970	20.007271	18.450293	3.448466	0.089903	0.082907	0.015496
Gwynt y mor	21.749280	21.503123	-	21.749280	21.503123	-	-	-	-
Hornsea 1A	7.654351	27.082288	-	7.741153	27.389407	-	0.086802	0.307119	-
Hornsea 1B	7.654351	27.082288	-	7.741153	27.389407	-	0.086802	0.307119	-
Hornsea 1C	7.654351	27.082288	-	7.741153	27.389407	-	0.086802	0.307119	-
Humber Gateway	12.799572	29.366622	-	12.799572	29.366622	-	-	-	-
Lincs	17.768864	69.878865	-	17.768864	69.878865	-	-	-	-
London Array	12.058331	41.343394	-	12.058331	41.343394	-	-	-	-
Ormonde	28.139373	52.598589	0.419167	28.266390	52.836011	0.421059	0.127017	0.237422	0.001892
Race Bank	10.258559	28.492731	-	10.258559	28.492731	-	-	-	-
Rampion				8.380255	21.922390	-			
Robin Rigg	- 0.617624	35.057595	11.232230	- 0.620411	35.215839	11.282931	- 0.002787	0.158244	0.050701
Robin Rigg West	- 0.617624	35.057595	11.232230	- 0.620411	35.215839	11.282931	- 0.002787	0.158244	0.050701
Sheringham Shoal	26.326570	31.006302	0.673986	26.445404	31.146260	0.677028	0.118834	0.139958	0.003042
Thanet	20.103644	37.664222	0.906711	20.194388	37.834233	0.910803	0.090744	0.170011	0.004092
Walney 1	24.303914	48.589703	-	24.413618	48.809029	-	0.109704	0.219326	-
Walney 2	22.611227	46.016100	-	22.713291	46.223810	-	0.102064	0.207710	-
Walney 3	10.537649	21.348645	-	10.537649	21.348645	-	-	-	-
Walney 4	10.537649	21.348645	-	10.537649	21.348645	-	-	-	-
West of Duddon Sands	9.424073	46.977768	-	9.424073	46.977768	-	-	-	-
Westermost Rough	19.162273	32.611753	-	19.162273	32.611753	-	-	-	-

Demand Tariffs

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

nationalgridESO

7. Demand tariffs summary

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

As per Draft tariffs, the methodology for 2022/23 demand tariffs remains unchanged. There has been no further update since Ofgem published their 'minded to position' on CMP343 to delay the implementation of the Transmission Demand Residual (TDR) banded charges until 2023/24.

Table 8 Summary of demand tariffs

HH Tariffs	2022/23 Draft	2022/23 Final	Change
Average Tariff (£/kW)	55.709982	55.062816	- 0.647166
Residual (£/kW)	57.495438	56.861767	- 0.633671

EET	2022/23 Draft	2022/23 Final	Change
Average Tariff (£/kW)	1.947578	2.075319	0.127741
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.344515	2.344515	-
Embedded Export Volume (GW)	7.361318	7.533414	0.172097
Total Credit (£m)	14.336744	15.634242	1.297498

NHH Tariffs	2022/23 Draft	2022/23 Final	Change
Average (p/kWh)	6.977935	6.809814	- 0.168121

From the publication of Draft tariffs, average HH & NHH demand tariffs have reduced, the main driver being the reduction in the total amount of revenue to be recovered through TNUoS and the change in revenue to be recovered through generation tariffs, reducing the proportion of revenue to be recovered through demand tariffs. There has also been a slight reduction in the total amount of revenue to be recovered through TNUoS, which will reduce total revenue required to be recovered through demand. Final tariffs for 2022/23 indicate that 76.6% of total revenue is to be recovered through demand, a decrease of 0.9% since Draft tariffs, with overall demand revenue set at £2,752m (decrease of £35m from Draft tariffs).

The average HH gross tariff is set at £55.06/kW, a decrease of £0.65/kW compared to Draft tariffs. The average NHH tariff is forecast at 6.81p/kWh, a decrease of 0.17p/kWh.

Overall, there has been a slight increase in forecasted Embedded Export Volume of 0.17GW to 7.53GW compared to the Draft tariff forecast. However, there has been a noticeable increase in the total credit paid out to embedded generators (<100MW), which is currently forecast at £15.6m, an increase of £1.3m. 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 increase in revenue due to the change in profile of zonal export volumes, has been offset slightly by a reduction in the tariffs. The average EET is now forecast at £2.08/kW an increase of £0.13/kW.

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	27.446662	3.558626	-
2	Southern Scotland	35.465718	4.395158	-
3	Northern	44.681931	5.280945	-
4	North West	51.407508	6.382111	-
5	Yorkshire	51.839430	6.199445	-
6	N Wales & Mersey	53.406721	6.460609	-
7	East Midlands	55.528462	6.954272	1.011210
8	Midlands	57.193871	7.145603	2.676619
9	Eastern	57.953489	7.696135	3.436237
10	South Wales	58.461967	6.630234	3.944715
11	South East	60.199079	8.057826	5.681827
12	London	63.687789	6.457749	9.170537
13	Southern	62.263662	7.854326	7.746409
14	South Western	63.747665	8.671244	9.230413

Residual charge for demand:	56.861767

Residual charge impact included in tariff calculation

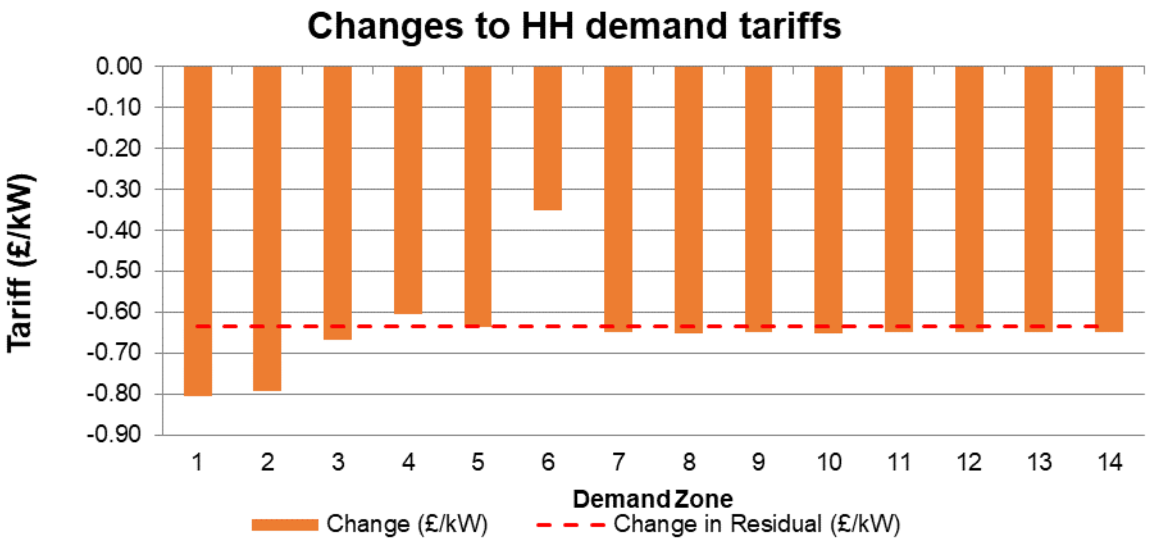
8. Half-Hourly demand tariffs

The table and figure below show the Final gross HH demand tariffs for 2022/23 compared to the Draft tariffs as well as the change in demand residual tariff (value is consistent across all zones).

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2022/23 Draft (£/kW)	2022/23 Final (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	28.251379	27.446662	- 0.804717	- 0.633671
2	Southern Scotland	36.260171	35.465718	- 0.794453	- 0.633671
3	Northern	45.349736	44.681931	- 0.667805	- 0.633671
4	North West	52.013201	51.407508	- 0.605693	- 0.633671
5	Yorkshire	52.475528	51.839430	- 0.636098	- 0.633671
6	N Wales & Mersey	53.757604	53.406721	- 0.350883	- 0.633671
7	East Midlands	56.176808	55.528462	- 0.648346	- 0.633671
8	Midlands	57.845875	57.193871	- 0.652004	- 0.633671
9	Eastern	58.601706	57.953489	- 0.648217	- 0.633671
10	South Wales	59.112712	58.461967	- 0.650745	- 0.633671
11	South East	60.848236	60.199079	- 0.649157	- 0.633671
12	London	64.336288	63.687789	- 0.648499	- 0.633671
13	Southern	62.913261	62.263662	- 0.649599	- 0.633671
14	South Western	64.397959	63.747665	- 0.650294	- 0.633671

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariffs have decreased across all zones since Draft tariffs. This is mainly due to the overall decrease in the demand residual tariff of £0.63/kW. There have been no updates to the Week 24 nodal demand and minimal changes which impact locational signals. There are minor changes to the generation charging base that impact demand location element which can be seen in Zone 6's tariff reduction. see Table

The forecast level of gross HH chargeable demand has increased slightly by <0.1GW in comparison with the Draft tariffs and is currently forecast at 19.41GW.

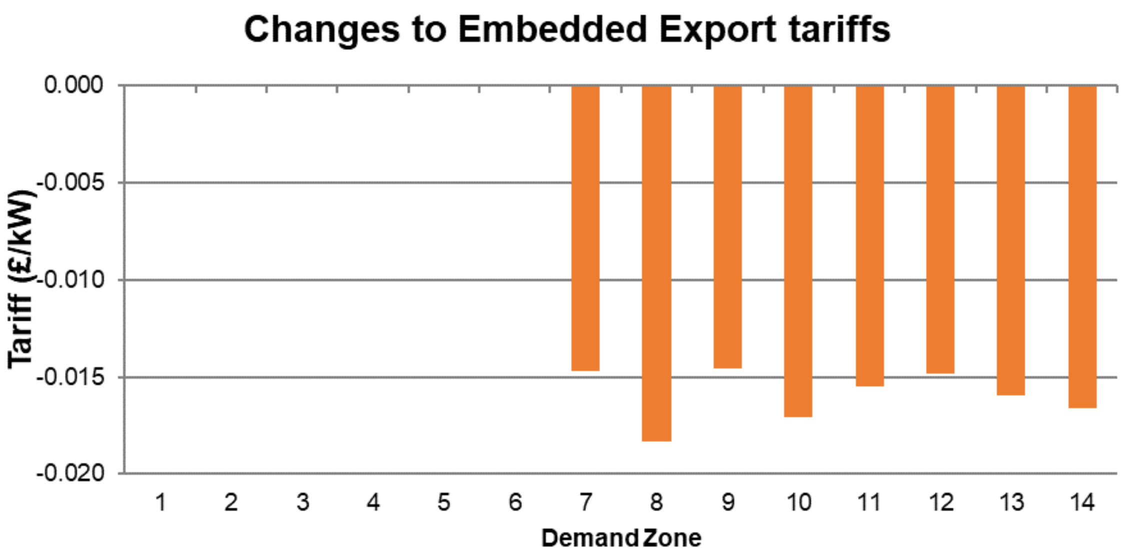
9. Embedded Export Tariffs (EET)

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

Table 11 Embedded Export Tariffs

Zone	Zone Name	2022/23 Draft (£/kW)	2022/23 Final (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.025885	1.011210	- 0.014675
8	Midlands	2.694952	2.676619	- 0.018333
9	Eastern	3.450783	3.436237	- 0.014546
10	South Wales	3.961789	3.944715	- 0.017074
11	South East	5.697313	5.681827	- 0.015486
12	London	9.185365	9.170537	- 0.014828
13	Southern	7.762338	7.746409	- 0.015929
14	South Western	9.247037	9.230413	- 0.016624

Figure 3 Embedded export tariff changes



There have been further noticeable changes to the average EET, as was the case for the comparison between Draft tariffs and the August forecast. This is due to a fluctuation in profile and an overall increase in the forecast Embedded Export Volumes. The increase in the revenue to be recovered from non-floored EET Zones (Zones 7-14) has increase due to an increase in forecast volumes for those Zones in contrast to those Zones that are floored (Zones 1-6), which can be seen in Table TAA in the tables file. The overall Embedded Export Volume has increased by 0.17GW to 7.53GW compared to Draft tariffs. There has been minimal change in tariffs and there has been no change to the avoided GSP Infrastructure Costs (AGIC) tariff which is set at £2.34/kW for 2022/23. The overall impact of these changes has increased the average EET by £0.13/kW to £2.95/kW.

As can be seen in the figure above there has been little to no changes across all non-floored Zones showing only a small reduction. Zones 1-6 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.

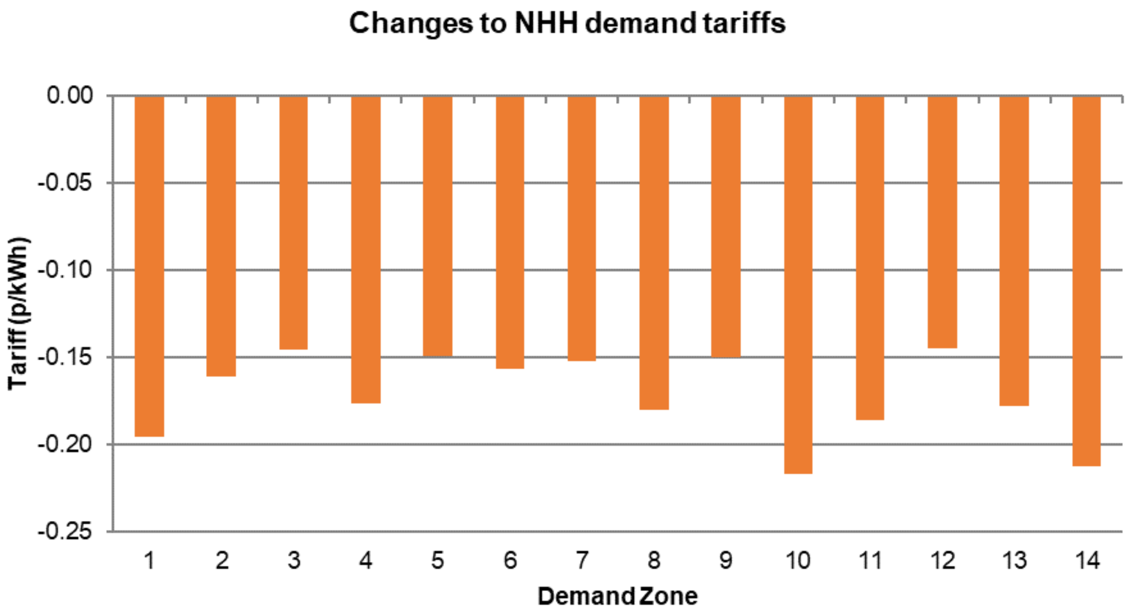
10. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2022/23 Final and Draft tariffs.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2022/23 Draft (p/kWh)	2022/23 Final (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.754234	3.558626	- 0.195608
2	Southern Scotland	4.556094	4.395158	- 0.160936
3	Northern	5.426633	5.280945	- 0.145688
4	North West	6.558575	6.382111	- 0.176464
5	Yorkshire	6.348318	6.199445	- 0.148873
6	N Wales & Mersey	6.617061	6.460609	- 0.156452
7	East Midlands	7.106220	6.954272	- 0.151948
8	Midlands	7.325327	7.145603	- 0.179724
9	Eastern	7.846331	7.696135	- 0.150196
10	South Wales	6.847104	6.630234	- 0.216870
11	South East	8.243977	8.057826	- 0.186151
12	London	6.602228	6.457749	- 0.144479
13	Southern	8.031774	7.854326	- 0.177448
14	South Western	8.883631	8.671244	- 0.212387

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2022/23 Final tariffs is set at 6.81p/kWh, a 0.17p/kWh decrease compared to Draft tariffs. As with the HH tariffs and the EET, the only significant impact to NHH tariffs since Draft tariffs has been the reduction in the overall revenue to be recovered through Demand tariffs. Changes in demand charging bases for HH/NHH and the update to location signals has been minimal and will have had very little impact on NHH tariffs.

As can be seen in the figure above, tariffs across all zones have decreased, however due to the multiple factors impacting NHH as mentioned above tariffs there are slight fluctuations across zones.

Overview of data inputs

This section explains the changes to the input data which are fed into the quarterly forecast process and subsequently into the Final tariffs.

11. Inputs affecting the locational element of tariffs

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

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

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2022/23 period onwards, which can be found on the TEC register.[11] The contracted TEC volumes are based on the October 2021 TEC register.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. For the initial and August forecasts, we forecasted 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 2021, 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 2022/23 and liable to pay generation TNUoS charges.

Table 13 Contracted TEC

	2021/22	2022/23 Tariffs			
Generation (GW)	Final	Initial	August	Draft	Final
Contracted TEC	89.90	89.91	87.66	85.50	85.03
Modelled Best View TEC	89.90	84.32	82.79	85.50	85.03
Chargeable TEC	70.10	74.93	73.40	72.53	72.44

2022/23 Draft column values updated to reflect the changes change in TEC for Shoreham that was not updated in the published Draft tariff report and tables file.

12. 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 2022/23 onwards as stated in the interconnector register as of 31st October 2021.

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

Table 14 Interconnectors

Interconnector	Site	Interconnected System	Generation Zone	Generation MW Transport Model Peak	Generation MW Transport Model Year Round	Generation MW Charging Base
Greenlink	Pembroke 400kV	Republic of Ireland	20	0	504	0
BritNed	Grain 400kV	Netherlands	24	0	1,200	0
IFA Interconnector	Sellindge 400kV	France	24	0	2,000	0
IFA2 Interconnector	Chilling 400KV Substation	France	26	0	1,100	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
ElecLink	Sellindge 400kV	France	24	0	1,000	0
NS Link	Blyth	Norway	13	0	1,400	0
Nemo Link	Richborough 400kV	Belgium	24	0	1,020	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	500	0

The change in Moyle interconnector TEC from 975MW to 500MW in Final tariffs for 2022/23 due to TEC register miscalculation in Draft tariffs. Can be seen above in Table 14

13. Expansion Constant and Inflation

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. The 2022/23 Expansion Constant is set at £15.462801/MWkm. It is required to be reset at the start of each price control and then inflated with agreed inflation methodology through the price control period. With the approval of CMP353 the current EC value is based on the RIIO-T1 value 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). For 2022/23 tariffs, CMP353 will continue, and updates will be provided on CMP315/375 which may impact 2023/24 tariffs.

14. Locational onshore security factor

The locational onshore security factor (also called the global security factor), set at 1.76 for the duration of RIIO-T2, is applied to locational tariffs. This parameter approximately represents the redundant network capacity to secure energy flows under network contingencies. A guidance to the onshore security factor calculation is published on our website https://www.nationalgrideso.com/document/183406/download

15. 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 Final tariffs, onshore substation tariffs are based on the values set for RIIO-T2 inflated by CPIH.

16. 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-T2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting.

17. 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. The total amount recovered is adjusted for interconnector revenue recovery or redistribution.

For onshore TOs, the allowed revenues have been based on TOs forecast reflecting Ofgem's final determination on their RIIO-T2 parameters including project spending profiles, rate of return and inflation index.

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

Table 15 Allowed revenues

£m Nominal	2022/23 TNUoS Revenue			
	April Initial Forecast	August Forecast	November Draft	January Final
TO Income from TNUoS				
National Grid Electricity Transmission	1,764.5	1,764.5	1,863.6	1,795.1
Scottish Power Transmission	348.7	371.9	350.5	357.9
SHE Transmission	632.7	632.6	652.8	673.2
Total TO Income from TNUoS	**2,745.8**	**2,768.9**	**2,866.9**	**2,826.2**
Other Income from TNUoS				
Other Pass-through from TNUoS	67.3	108.5	169.3	173.6
Offshore (plus interconnector contribution / allowance)	552.8	557.2	568.0	594.5
Total Other Income from TNUoS	**620.2**	**665.7**	**737.4**	**768.1**
Total to Collect from TNUoS	**3,366.0**	**3,434.6**	**3,604.3**	**3,594.3**

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The G/D split forecast is shown in table 16.

In this forecast, we have removed CMP368/369 (chargeable embedded generators and pre-existing assets charges for gen cap) from the 22/23 tariffs. Our final tariffs reflect the currently approved CUSC modifications and therefore do not include CMP368/369 impacts.

Table 16 Generation and demand revenue proportions

Code	Revenue	2022/23 Tariffs April Initial Forecast	August Forecast	November Draft	January Final
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5
y	Error Margin	20.8%	14.2%	14.2%	14.2%
ER	Exchange Rate (€/£)	1.13	1.13	1.17	1.17
MAR	Total Revenue (£m)	3,366.0	3,434.6	3,604.3	3,594.3
GO	Generation Output (TWh)	210.0	196.4	196.4	196.4
G	% of revenue from generation	24.84%	24.32%	22.66%	23.43%
D	% of revenue from demand	75.16%	75.68%	77.34%	76.57%
G.R	Revenue recovered from generation (£m)	836.2	835.2	816.6	842.0
D.R	Revenue recovered from demand (£m)	2,529.8	2,599.4	2,787.7	2,752.3
Breakdown of generation revenue					
	Revenue from the Peak element	138.2	124.3	129.4	128.9
	Revenue from the Year Round Shared element	108.4	112.1	105.1	98.6
	Revenue from the Year Round Not Shared element	143.3	151.0	137.7	149.6
	Revenue from Onshore Local Circuit tariffs	16.1	15.6	16.3	16.2
	Revenue from Onshore Local Substation tariffs	10.5	9.9	9.9	9.9
	Revenue from Offshore Local tariffs	451.0	446.8	439.5	455.2
	Revenue from the adjustment element	-31.3	-24.4	-21.2	-16.6
G.MAR	Total Revenue recovered from generation (£m)	836.2	835.2	816.6	842.0
	Revenue from large embedded generation (£m)	7.1	7.1	8.7	0.0
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.9	1.9	2.4	0.0

The “gen cap”

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

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 were approved in December 2020 and were included in the 2021/22 final tariffs. When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod, to update charges for the physical assets required for connection, generation output and Generator charges associated with TNUoS-chargeable embedded generators, for the purpose of maintaining compliance with the Limiting Regulation (the [0 ~ €2.50]/MWh range). The ESO has raised this CUSC mod (CMP368/369)[12], which was proposed to be implemented from April 2022/23. The latest development on the CMP317/327 legal challenge, means CMP368/369 is not approved yet. Therefore, our final tariffs here do not include CMP368/369 impacts but do include CMP317/327 impacts.

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 exchange rate remains unchanged at €1.127740/£ since the Draft tariffs.

Generation Output

The forecast output of generation is 196.38TWh. This figure is the average of the four scenarios (plus the central case) in the 2021 Future Energy Scenarios publication and is the final value used to set the Final tariffs for 2022/23.

[12] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp368-cmp369

Error Margin

The error margin has been recalculated in the August forecast, following publication of the outturn of 2020/21 data. The error margin is derived from historical data in the past five whole years (thus for year 2022/23, we use data from years 2016/17 – 2020/21).

Table 17 Generation revenue error margin calculation

Calculation for	2022/23		
	Revenue inputs		Generation output variance
Data from year:	Revenue variance	Adjusted variance	
2016/17	-5.1%	4.4%	-7.9%
2017/18	-5.2%	4.3%	-1.5%
2018/19	-9.2%	0.3%	-7.5%
2019/20	-14.6%	-5.2%	-4.1%
2020/21	-13.2%	-3.7%	7.5%
Systemic error:	-9.5%		
Adjusted error:		5.2%	7.9%
Error margin =			14.2%

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

19. Charging bases for 2022/23

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 2022/23 final tariffs is forecast at 72.4GW and is based on our internal view of what generation we expect to connect next financial year. This is a decrease of 0.1GW since Draft tariff forecast which is mainly driven by the delay in connection date of a couple of small generators.

For the Final Tariffs, in line with the CUSC, we use the contracted TEC position as of 31st October 2021 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 2022/23.

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

- Historical gross metered demand and embedded export volumes (April 2018 -December 2021)
- 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 November Draft for 2022/23 based on the latest demand outturn data up to end of December 2021. Please refer to table TAA in the published tables spreadsheet for a detailed breakdown of the changes to the demand changing bases.

Table 18 Charging bases

	2022/23 Tariffs			
Charging Bases	Initial	August	Draft	Final
Generation (GW)	74.93	73.40	72.53	72.44
NHH Demand (4pm-7pm TWh)	24.18	24.84	24.70	24.96
Gross charging				
Total Average Gross Triad (GW)	49.83	50.61	50.47	50.44
HH Demand Average Gross Triad (GW)	19.07	19.17	19.36	19.41
Embedded Generation Export (GW)	6.54	7.01	7.36	7.53

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of of Final tariffs, we have used the final version of the 2022/23 ALFs. ALFs are explained in more detail in Appendix D of this report, and the full list of power station ALFs are available on the National Grid ESO website.[13]

21. Generation adjustment and demand residual

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

Generation Adjustment = (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 generation 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)

[13] https://www.nationalgrideso.com/document/186166/download

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

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

The **Demand Residual** = (Total demand revenue less revenue recovered from locational demand tariffs, plus revenue paid to embedded exports) divided by total system gross triad demand

$$R_D = \frac{D.R - Z_D + EE}{B_D}$$

Where:

- R_D is the gross demand residual tariff (£/kW)
- D is the proportion of TNUoS revenue recovered from demand
- R is the total TNUoS revenue to be recovered (£m)
- Z_D is the TNUoS revenue recovered from demand locational zonal tariffs (£m)
- EE is the amount to be paid to embedded export volumes through the Embedded Export Tariff (£m)
- B_D is the demand charging base (HH equivalent GW)

Z_G, Z_D, and EE are determined by the locational elements of tariffs. The EE is also affected by the value of the AGIC[14].

Ofgem's minded-to decision is that changes to the demand residual tariffs will apply in 2023/24, i.e. the existing demand non-locational tariff will be replaced with a new set of £/site charges on final demand users, based on site banding. As these changes are expected to not apply until April 2023, they have not been included in 2022/23 Final Tariffs.

[14] Avoided Grid Supply Point Infrastructure Credit

Table 19 Residual & Adjustment components calculation

	Component	2022/23 Tariffs Initial	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	24.84%	24.32%	22.66%	23.43%
D	Proportion of revenue recovered from demand (%)	75.16%	75.68%	77.34%	76.57%
R	Total TNUoS revenue (£m)	3,366.00	3,434.62	3,604.29	3,594.25
Generation revenue breakdown (without adjustment)					
Z_G	Revenue recovered from the wider locational element of generator tariff	389.9	387.4	372.2	377.2
O	Revenue recovered from offshore local tariffs (£m)	451.0	446.8	439.5	455.2
L_G	Revenue recovered from onshore local substation tariffs (£m)	10.5	9.9	9.9	9.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	16.1	15.6	16.3	16.2
	Revenue from large embedded generation (£m)	7.1	7.1	8.7	0.0
	Revenue from local charges associated with pre-existing assets (indicativ	1.9	1.9	2.4	0.0
Generation adjustment tariff calculation					
	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5
	Error Margin	20.8%	14.2%	14.2%	14.2%
	Exchange Rate (€/£)	1.13	1.13	1.17	1.17
	Total generation Output (TWh)	210.0	196.4	196.4	196.4
	Generation Output from TNUoS chargeable EGs (TWh)	0.0	8.3	8.7	0.0
	Generation revenue subject to the [0,2.50]Euro/MWh range (£m)	367.9	357.8	344.6	360.6
	Adjustment Revenue (£m)	-16.8	-24.4	-21.2	-16.6
BG	Generator charging base (GW)	74.9	73.4	72.5	72.4
AdjTariff	Generator adjusment tariff (£/kW)	-0.22	-0.33	-0.29	-0.23
Gross demand residual					
R_D	Demand residual tariff (£/kW)	53.14	53.77	57.50	56.86
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-104.39	-106.27	-99.98	-100.12
EE	Amount to be paid to Embedded Export Tariffs (£m)	13.98	15.58	14.34	15.63
B_D	Demand Gross charging base (GW)	49.83	50.61	50.47	50.44

Tools and supporting information

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

Charging webinars

We will be hosting a webinar for the Final Forecast on Tuesday 15th February. 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/235026/download

This data can also be accessed via our Data Portal:

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

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

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage and cable / overhead line, and the costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions, which means that they reflect the cost of replacing assets at current rather than historical cost, so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site.

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and demand tariffs. The residual for demand, and adjustment for generation, is also used to ensure the correct proportion of revenue is collected from demand and generation. The locational and residual / adjustment tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate.

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

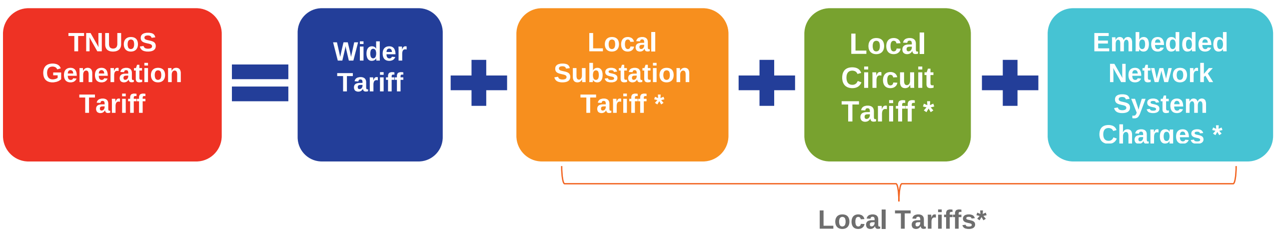
Generation charging principles

Transmission connected generators (and embedded generators with TEC >= 100MW) are subject to the generation TNUoS charges.

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC (Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to export onto the transmission network.

Under the current methodology there are 27 generation zones, and each zone has four tariffs. Liability for each tariff component is shown below:

TNUoS tariffs are made up of two general components, the **Wider tariff**, and **local tariffs**.



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

The Wider tariff is set to recover the costs incurred by the generator for the use of the whole system, whereas the local tariffs are for the use of assets in the immediate vicinity of the connection site.

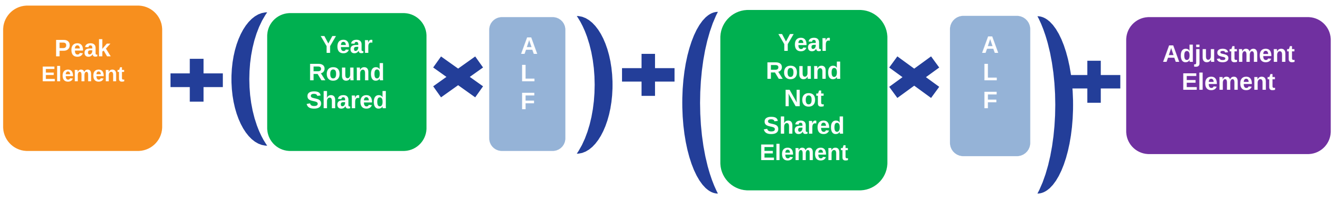
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

The Wider tariff is made up of four components, two of which may be multiplied by the generator's specific Annual Load Factor (ALF), depending on the generator type.

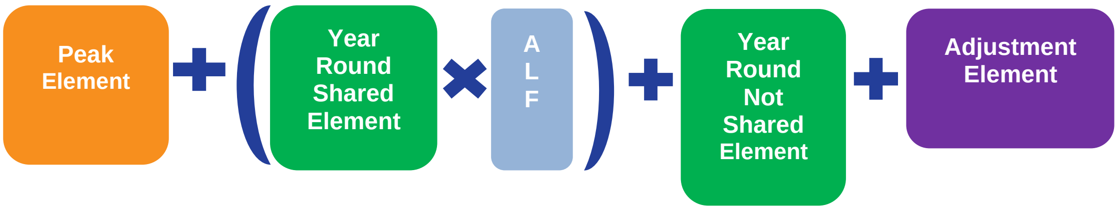
Conventional Carbon Generators

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



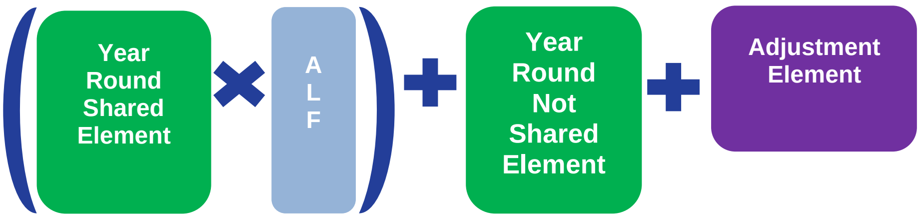
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

The **Adjustment** element 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 charge 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 each year from the start of the RIIO-T2 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[15] if they want to export power onto the transmission system from the distribution network using "firm" transmission network capacity. Generators will incur local DUoS[16] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

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

The calculation for TNUoS generator monthly liability is as follows:

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

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

TNUoS charges are billed each month for the month ahead.

Generators with negative TNUoS tariffs

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

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

[16] Distribution network Use of System charges

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

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

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers have two specific tariffs following the implementation of CMP264/265, which are for gross HH demand and embedded export volumes; NHH customers have another specific tariff.

HH gross demand tariffs

HH gross demand tariffs are made up of locational and residual 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.[17] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data are available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[18].

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[19].

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

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

NHH demand tariffs

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

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.

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[17] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data
[18] https://www.nationalgrideso.com/document/130641/download
[19] https://www.nationalgrideso.com/charging/charging-guidance

Appendix B: Changes and proposed changes to the charging methodology

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Changes and proposed changes to the charging methodology

There have been no relevant CUSC methodology changes since the 2021/22 Final tariffs that impact the 2022/23 tariffs.

Appendix C: Breakdown of locational HH and EE tariffs

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Locational components of demand tariffs

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

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

Table 20 Location elements of the HH demand tariff for 2022/23

Demand Zone		2022/23 Draft		2022/23 Final		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.378353	-26.865706	-2.178226	-27.236880	0.200127	-0.371174
2	Southern Scotland	-2.666540	-18.568727	-2.588187	-18.807862	0.078353	-0.239134
3	Northern	-4.209072	-7.936630	-4.334540	-7.845295	-0.125468	0.091335
4	North West	-1.526881	-3.955356	-1.522583	-3.931676	0.004298	0.023680
5	Yorkshire	-3.069356	-1.950554	-3.111358	-1.910980	-0.042002	0.039574
6	N Wales & Mersey	-2.178954	-1.558879	-1.977716	-1.477330	0.201239	0.081549
7	East Midlands	-2.747019	1.428389	-2.753986	1.420681	-0.006967	-0.007708
8	Midlands	-1.364659	1.715097	-1.348947	1.681051	0.015712	-0.034046
9	Eastern	0.473848	0.632420	0.445125	0.646597	-0.028723	0.014177
10	South Wales	-3.503913	5.121186	-3.519338	5.119538	-0.015425	-0.001649
11	South East	3.648368	-0.295570	3.640164	-0.302852	-0.008205	-0.007282
12	London	4.511476	2.329373	4.486793	2.339230	-0.024684	0.009856
13	Southern	2.541405	2.876418	2.537729	2.864165	-0.003676	-0.012253
14	South Western	1.925710	4.976812	1.880963	5.004935	-0.044747	0.028123

Table 21 Elements of the Embedded Export Tariff for 2022/23

Demand Zone		2022/23 Draft		2022/23 Final		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	-29.244059	2.344515	-29.415106	2.344515	-0.171047	0.000000
2	Southern Scotland	-21.235267	2.344515	-21.396049	2.344515	-0.160782	0.000000
3	Northern	-12.145702	2.344515	-12.179836	2.344515	-0.034133	0.000000
4	North West	-5.482237	2.344515	-5.454259	2.344515	0.027978	0.000000
5	Yorkshire	-5.019910	2.344515	-5.022337	2.344515	-0.002427	0.000000
6	N Wales & Mersey	-3.737834	2.344515	-3.455046	2.344515	0.282788	0.000000
7	East Midlands	-1.318630	2.344515	-1.333305	2.344515	-0.014675	0.000000
8	Midlands	0.350437	2.344515	0.332104	2.344515	-0.018333	0.000000
9	Eastern	1.106268	2.344515	1.091722	2.344515	-0.014546	0.000000
10	South Wales	1.617274	2.344515	1.600200	2.344515	-0.017074	0.000000
11	South East	3.352798	2.344515	3.337312	2.344515	-0.015487	0.000000
12	London	6.840850	2.344515	6.826022	2.344515	-0.014827	0.000000
13	Southern	5.417823	2.344515	5.401894	2.344515	-0.015928	0.000000
14	South Western	6.902522	2.344515	6.885898	2.344515	-0.016624	0.000000

Appendix D: Annual Load Factors

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ALFs

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

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

The specific and generic ALFs that apply to the 2022/23 Final Tariffs are published here, with specific ALFs in excel format here.

Generic ALFs

Table 22 Generic ALFs

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

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

These Generic ALFs are calculated in accordance with CUSC 14.15.110.

Appendix E: Contracted generation

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

The contracted generation used in the Transport model is fixed using the TEC register as of 31 October 2021, as stated by the CUSC 14.15.6 and no further changes or updates are made from Draft Tariffs regarding Contracted TEC. However as can be seen in Table 23, an error in the calculation of the TEC value from the 31 October 2021 Interconnector Register for the Moyle interconnector which was used in the Draft tariff calculation has since been corrected. The 2022/23 Final tariffs reflect this change In Contracted TEC.

Table 23 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Moyle Interconnector	-475	AUCH20	10

Appendix F: Transmission company revenues

Transmission Owner revenue forecasts

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

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

Notes:

All monies are quoted in millions of pounds, accurate to two decimal place and are in nominal 'money of the day' prices unless stated otherwise.

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. NGESO and TOs offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither NGESO nor TOs accept or assume responsibility for the use of this information by any person or any person to whom this information is shown or any person to whom this information otherwise becomes available.

NGESO TNUoS revenue pass-through items forecasts

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

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

Since our November forecast, it can be observed that there is an additional £4m of pass-through revenue. This aggregate increase is made of a few variables which have all changed by a small degree (see table 25) with the most notable variations being seen with increases in Network Innovation Competition Fund value (+£10m following Ofgem indication in January), the Licence Fee (+£3m as actuals replaces forecast data), the Adjustment Factor (+£2m as actuals replaces forecast data), and decreases in Inter-Transmission System Operator Compensation (-£7m following a review of the forecast based on wholesale prices) and bad debt (-£3m following review of forecast).

Table 24 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through			
	Initial Forecast	August Forecast	November Draft	January Final
Embedded Offshore Pass-Through (OFETt)	0.58	0.58	0.58	0.70
Network Innovation Competition Fund (NICFt)	30.89	30.89	0.00	9.68
Strategic Innovation Fund (SIFt)	0.00	0.00	18.04	18.04
The Adjustment Term (ADJt)	0.00	0.00	63.04	65.11
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	552.85	557.23	568.05	594.51
Interconnectors CACM Cost Recovery (ICPt)	0.00	0.00	0.00	0.00
Site Specific Charges Discrepancy (DISt)	0.00	0.00	0.37	0.00
Termination Sums (TSt)	0.00	0.00	0.00	0.00
NGET revenue pas-through (NGETTOt)*	1,764.46	1,764.46	1,863.63	1,795.07
SPT revenue pass-through (TSPt)	348.71	371.85	350.45	357.86
SHETL revenue pass-through (TSHt)	632.65	632.61	652.85	673.24
ESO Bad debt (BDt)	3.30	3.30	7.20	3.60
ESO other pass-through items (LFt + ITCt etc)	32.56	32.56	42.53	38.90
ESO legacy adjustment (LARt)	0.00	41.13	37.55	37.55
Total	3,366.00	3,434.62	3,604.29	3,594.25

The Adjustment Term is a new addition for the 2022/23 tariff period and is the difference between our expected 2021/22 tariffs (as published in January 2021) and the known revenue required for 2021/22 at the time of this tariff publication. As such for this year only, it also contains the k-factor from 2021/22 (£49.6m).

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 final revenue breakdown for 2022/23. Most notably the recent submissions include a revision following the CMA Final Determination, the Ofgem decision regarding Western Link Project and an increase in interest rates.

The CMA Final Determination ruled to remove the outperformance wedge (designed to reduce the TOs cost of equity). The cost of equity flows into the Weighted Average Cost of Capital used to calculate the TO's returns so as the cost of equity increases, this will be noticeable in the calculated revenue.

The Western Link Project determination implemented a redress of £158m to be distributed between NGET and SPT. As such, most notably in NGET, the Maximum Allowed Revenue has reduced to accommodate this.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2022/23 is forecast to be £594.51m, an increase of £26.5m from the Draft forecast. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to latest RPI data (as part of the calculation of the inflation term, as defined in the relevant OFTO licence).

Since year 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework, and interconnectors' Cap & Floor framework. There have been no changes to the Interconnector Adjustment which remains at £0m.

Table 25 NGET revenue breakdown

Transmission Revenue Forecast			National Grid Electricity Transmission				Notes
			Initial Forecast	August Forecast	November Draft	January Final	
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	n/a	302.65	309.79	316.99	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	1,634.08	1,669.51	1,673.81	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	73.50	102.96	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	1,745.64	1,899.06	1,975.75	
SONIA	B1	It-1	n/a	0.05%	0.07%	0.19%	
Allowed Revenue	B2	ARt-1	n/a	1,755.30	1,749.23	1,749.24	
Recovered Revenue	B4	RRt-1	n/a	1,755.30	1,755.30	1,755.30	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	-6.14	-6.14	
Legacy pass-through	C1	LPt	n/a	0.00	3.78	3.84	
Legacy MOD	C2	LMODt	n/a	21.43	-32.65	-177.66	
Legacy K correction	C3	LKt	n/a	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	n/a	-2.60	-23.28	-23.67	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00	17.55	17.55	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incenti	C7	LSFIt	n/a	0.00	0.84	0.85	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00	4.48	4.55	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	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	n/a	18.82	-29.28	-174.53	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	1,764.46	1,764.46	1,863.63	1,795.07	

Table 26 SPT revenue breakdown

Transmission Revenue Forecast			Scottish Power Transmission				Notes
			Initial Forecast	August Forecast	November Draft	January Final	
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	n/a	302.65	309.79	316.99	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	345.77	328.98	331.12	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	-8.10	-1.50	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	369.38	351.63	368.99	
SONIA	B1	It-1	n/a	0.09%	0.07%	0.19%	
Allowed Revenue	B2	ARt-1	n/a	371.85	376.93	376.93	
Recovered Revenue	B4	RRt-1	n/a	371.85	373.12	382.81	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	3.86	-5.96	
Legacy pass-through	C1	LPt	n/a	0.00	3.65	3.71	
Legacy MOD	C2	LMODt	n/a	2.48	-8.83	-8.97	
Legacy K correction	C3	LKt	n/a	0.00	0.00	0.00	
Legacy TRU term	C4	LTRUt	n/a	0.00	-5.36	-5.45	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	0.00	2.64	2.64	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	0.00	0.00	0.00	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incenti	C7	LSFIt	n/a	0.00	0.17	0.17	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	0.00	2.68	2.73	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	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	n/a	2.48	-5.04	-5.16	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	348.71	371.85	350.45	357.86	

Table 27 SHETL revenue breakdown

Transmission Revenue Forecast			SHE Transmission Initial Forecast	August Forecast	November Draft	January Final	Notes
Inflation 2018/19		$PI_{2018/19}$	n/a	283.31	283.31	283.31	April to March 2018/19 average RPI
Inflation		PI_t	n/a	302.65	309.79	316.99	Blended RPI-CPIH Inflation
Opening Base Revenue Allowance (2018/19 prices)	A1	Rt	n/a	540.60	544.75	528.34	
Price Control Financial Model Iteration Adjustment	A2	ADJ_t	n/a	0.00	0.00	-2.06	
$[ADJR_t = R_t * PI_t / PI_{2018/19} + ADJ_t]$	A	$ADJR_t$	n/a	577.51	595.66	589.08	
SONIA	B1	It-1	n/a	0.05%	0.07%	0.19%	
Allowed Revenue	B2	ARt-1	n/a	582.60	584.75	578.30	
Recovered Revenue	B4	RRt-1	n/a	582.60	582.90	582.90	
Correction Term $[K_t = (AR_{t-1} - RR_{t-1}) * (1 + I_{t-1} + 1.15\%)]$	B	K_t	0.00	0.00	1.88	-4.66	
Legacy pass-through	C1	LPt	n/a	30.30	30.00	30.86	
Legacy MOD	C2	LMODt	n/a	20.80	20.44	57.66	
Legacy K correction	C3	LKt	n/a	0.00	5.27	0.00	
Legacy TRU term	C4	LTRUt	n/a	-0.40	-3.69	-5.22	
Close out of the RIIO-ET1 stakeholder satisfaction output	C5	LSSOt	n/a	1.60	1.60	2.47	
Close out of the RIIO-1 adjustment in respect of the Environmental Discretionary Reward Scheme	C6	LEDRt	n/a	1.00	0.00	1.33	
Close out of the RIIO-ET1 Incentive in respect of the sulphur hexafluoride (SF6) gas emissions incenti	C7	LSFIt	n/a	0.00	-0.11	-0.11	
Close out of the RIIO-ET1 reliability incentive in respect of energy not supplied	C8	LRIt	n/a	1.80	1.79	1.84	
Close out of RIIO-1 Network Outputs	C9	NOCOt	n/a	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	n/a	55.10	55.31	88.83	
Total Allowed Revenue $[AR_t = ADJR_t + K_t + LAR_t]$	D	AR_t	632.65	632.61	652.85	673.24	

Table 28 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	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.7	7.0	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	8.7	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	15.6	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	9.8	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	16.3	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	24.2	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	14.7	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	33.2	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.7	46.8	Current revenues plus indexation
Thanet	78.9	17.4	15.7	19.5	18.6	19.2	19.7	20.8	21.6	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.0	32.5	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	32.9	39.8	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	25.3	25.5	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	14.4	13.3	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.1	14.7	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	14.7	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	20.8	Current revenues plus indexation
Race Bank						66.0	26.7	27.4	28.9	Current revenues plus indexation
Galloper							16.1	17.1	17.8	Current revenues plus indexation
Walney 3							28.8	13.5	14.1	Current revenues plus indexation
Walney 4								13.5	14.1	Current revenues plus indexation
Hornsea 1A								137.1	18.4	Current revenues plus indexation
Hornsea 1B									18.4	Current revenues plus indexation
Hornsea 1C									18.4	Current revenues plus indexation
Beatrice									21.1	Current revenues plus indexation
Rampion									15.5	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2021/22									0.0	National Grid Forecast
Forecast to asset transfer to OFTO in 2022/23									68.3	National Grid Forecast
Offshore Transmission Pass-Through (B7)	218.4	248.3	260.8	265.5	318.0	390.6	387.0	549.0	594.3	

Notes:

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

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

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

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

Appendix G: Generation zones map

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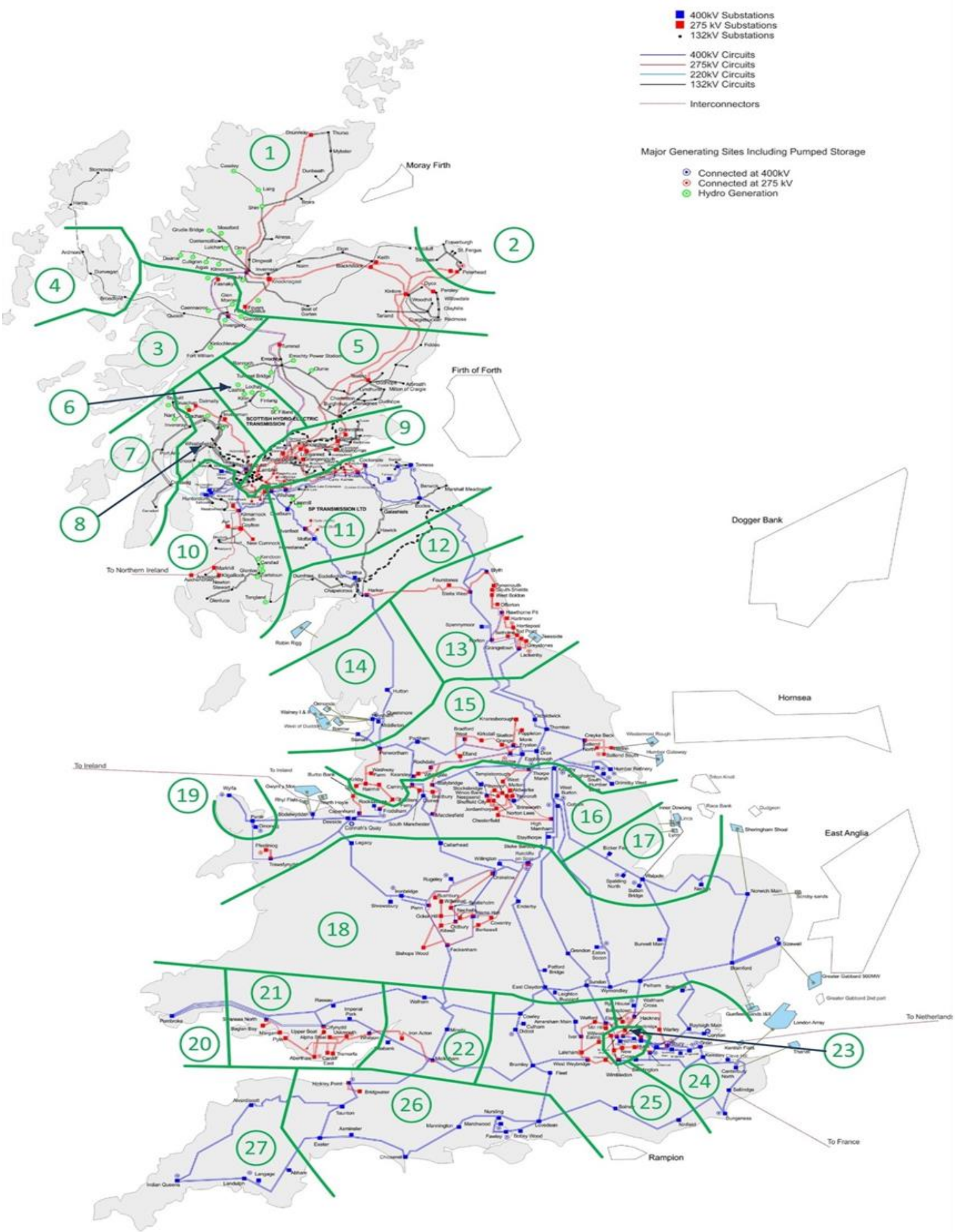
Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



Appendix H: Demand zones map

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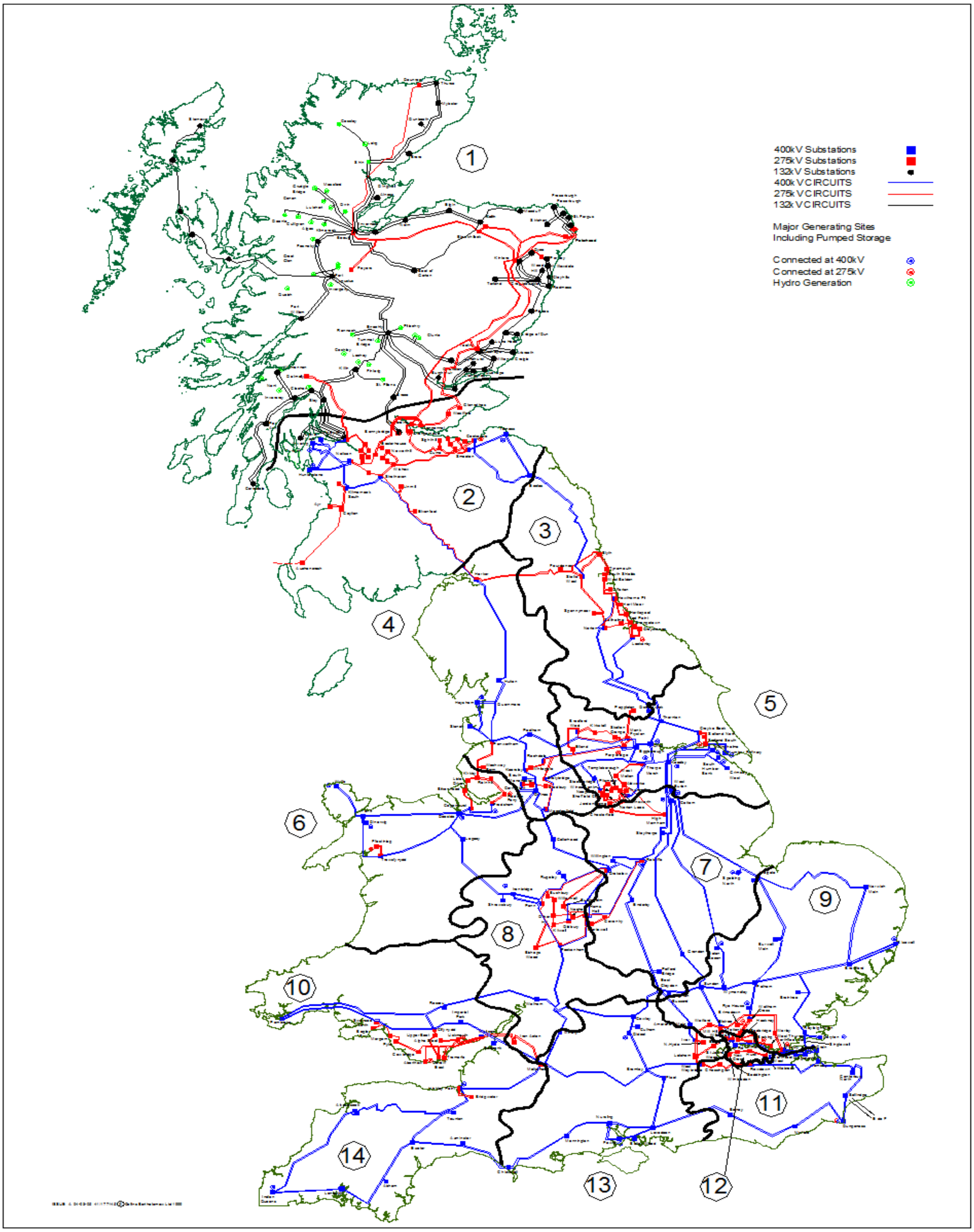
Appendix H: Demand zones map



Appendix I: Changes to TNUoS parameters

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Parameters affecting TNUoS tariffs

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

2022/23TNUoS Tariff Forecast					
		April 2021	**August 2021**	**Draft Tariffs November 2021**	**Final Tariffs January 2022**
Methodology		*Open to industry governance*			
LOCATIONAL	**DNO/DCC Demand Data**	Initial update using previous year's data source		Week 24 updated	
LOCATIONAL	**Contracted TEC**	Latest TEC Register	Latest TEC Register	TEC Register Frozen on 31 October*	
LOCATIONAL	**Network Model**	Initial update using previous year's data source (except local circuit changes which are updated quarterly)		Latest version based on ETYS	
LOCATIONAL	**CPIH**	forecast			actual
RESIDUAL / ADJUSTMENT	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	NG best view
RESIDUAL / ADJUSTMENT	**Allowed Revenue** *(non OFTO changes)*	Initial update using previous year's data source	Update financial parameters	Latest TO forecasts	From TOs
RESIDUAL / ADJUSTMENT	**Demand Charging Bases**	Initial update using previous year's data source	Revised forecast	Revised forecast	Revised by exception
RESIDUAL / ADJUSTMENT	**Generation Charging Base**	NG best view	NG best view	NG best view	NG final best view
RESIDUAL / ADJUSTMENT	**Generation ALFs**	Previous year's data source		New ALFs published	
RESIDUAL / ADJUSTMENT	**Generation Revenue** (G/D split)	Forecast	Forecast	Forecast	Generation revenue £m fixed

*Overall *Contracted TEC updated for 2022/23 Final tariffs due to an error with the calculation of the Moyle interconnector TEC which was present in the Draft Tariffs*

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