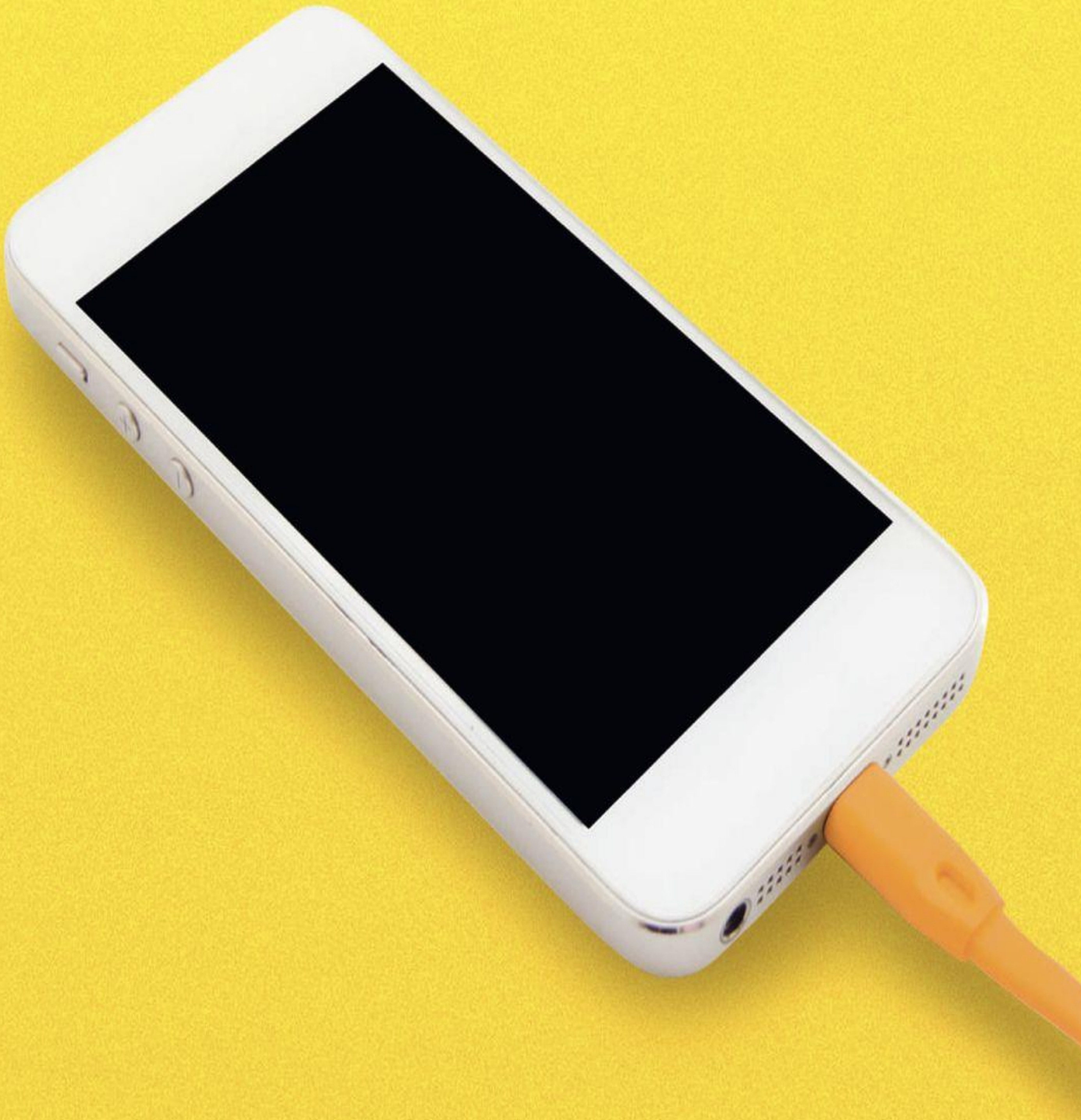
nationalgridESO

Forecast TNUoS Tariffs for 2021/22

National Grid Electricity System Operator

March 2020



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Executive summary

Transmission Network Use of System (TNUoS) charge is designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. It is applicable to transmission connected generators and suppliers for use of the transmission networks. This document contains the Forecast TNUoS Tariffs for 2021/22.

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 initial forecast of Transmission Network Use of System (TNUoS) tariffs for year 2021/22 (March Tariffs) on our website[1].

This Forecast is for charging year 2021/22 and has no impact on 2020/21.

We fully appreciate that there are uncertainties with several ongoing charging methodology changes. We therefore have also included a number of sensitivity scenario analysis to help the industry to understand the potential implications. We will provide updates on the TNUoS tariffs through the year and finalise by January 2021.

TCR Impact

Ofgem's decision on the Targeted Charging Review (TCR) will affect TNUoS tariffs in two aspects, the Transmission Generation Residual (TGR) and the Transmission Demand Residual (TDR). TGR changes will be implemented from April 2021 and will affect generation residual tariffs, while TDR changes will be deferred to April 2022. In this forecast, we have included TGR only. But to provide an early view of the potential implications under TDR, we have also included TDR as a sensitivity case.

RIIO-2 Impact

The charging year 2021/22 will be in the new RIIO-2 price control period for onshore transmission owners. There are various parameters that are due to be revised at the start of each price control, based on data from the new price control period. We are reviewing these RIIO-2 related elements, which are to be finalised after Ofgem makes final decision on RIIO-2. In this report, we have calculated indicative offshore local tariffs for RIIO-2 but used inflated RIIO-1 parameters for other elements, and they are listed in the Forecast Overview section.

In this forecast, we have kept the same number of generation zones (27 in total) as in RIIO-1, to provide like-for-like comparison with last year's tariffs. Generation zoning criteria are being reviewed by CMP324/325 workgroup, and the CUSC mods have not been concluded. We have also included two sensitivities on alternative generation zone numbers (14 zones and 48 zones respectively), to provide an early view of the generation wider tariffs under alternative zoning criteria.

Total revenues to be recovered

Total revenue to be collected is forecast at £3,053m, an increase of £210m from 2020/21 charging year. The forecast was provided by TOs' based on RIIO-1 parameter assumptions. These forecasts will be updated through the year and finalised by January Final Tariffs.

Generation tariffs

The total revenue to be recovered from generators is £820.6m, increased of £446m from 2020/21. This significant increase is mainly driven by the Targeted Charging Review (TCR) change, which intends to remove the generation residual from TNUoS charge.

The generation charging base has been updated to 76.8GW based on our best view on generation projects for 2021/22. This view will be further refined throughout the year. With increased generation revenue, the average generation tariff increased by £5.39/kW to £10.69 /kW and the residual tariff increased by £4.48/kW to -£0.37/kw.

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

Small Generator Discount

As defined in the NGESO's licence, the Small Generator Discount (SGD) reduces the tariff for transmission connected generation connected at 132kV and with Transmission Export Capacity (TEC) <100MW and the SGD is expected to expire by March 2021. As such, we have not included the SGD in the tariffs.

Demand tariffs

The revenue to be recovered from demand tariffs is forecast to be £2,232.6m in 2021/22. This value has decreased by £244.7m compared to the 2020/21 Final Tariffs. The reduction is a result of increased revenue to be collected from generators. The impact on the end consumer is forecast to be £32.02 per year, a reduction of £1.71 compared to 2020/21.

£17.1m will be payable through the Embedded Export Tariff (EET). This remains the same as in 2020/21. The average EET is £2.37/kW.

Not including the effect of the Small Generator Discount, the average gross HH demand tariff is forecast to be £45.26/kW, a decrease of £4.31/kW. The average NHH demand tariff is 5.72p/kWh, a decrease of 0.30p/kWh.

Sensitivity Scenarios

We are conscious that there is considerable uncertainty given the changes to the underlying framework. We believe that it would be helpful to provide a number of sensitivity scenarios, including:

- If different numbers of generation zones are applied,
- If the Small Generator Discount extends
- If the Transmission Demand Residual (TDR) is incorporated

We will refine the forecast throughout the year as we get greater certainty around the charging framework.

Next TNUoS tariff publications

Our next TNUoS tariff publication will be the five-year view of 2021/22 – 2025/26 tariffs in August 2020.

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

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1
Forecast Overview

This report

This report contains the initial forecast of TNUoS for the charging year 2021/22.

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

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

Changes to the methodology due to Ofgem's Targeted Charging Review (TCR)

On 21 November 2019, the Authority published their final decision[2] 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 will take effect from April 2021.

Under the TCR, the two changes for TNUoS tariff setting and charges are:

- The removal of the generation residual, which is currently used to keep total TNUoS recovery from generators within the range of €0-2.50/MWh. This change will be managed under CMP317/327, which seeks to ensure ongoing compliance with European Regulation by establishing which charges are, and are not in scope of that range; and
- The creation of specific NHH and HH demand residual charges, levied only to final demand (which is consumption not used either to operate a generating station, or to store and export), and on a 'site' basis. CMP332 (Transmission Demand Residual bandings and allocation) was raised to modify the CUSC methodology accordingly.

Our 2021/22 tariff forecast is largely based on the approved methodology in the CUSC. However, we have also incorporated the potential impacts by TGR which is due to take effect from April 2021, to illustrate the likely magnitudes of tariffs changes to customers.

Changes to the methodology due to Ofgem's Review of Access and Forward-Looking Charges (RAFLC)

In December 2018, Ofgem launched their Significant Code Review (SCR) in Access and Forward-Looking Charging[3]. In scope is a review of the definition and choice of access rights for transmission and distribution users, a wide-ranging review of distribution network charges, a review of the distribution connection charging boundary and a focussed review of TNUoS charges.

Ofgem published a number of working papers and other discussion materials in 2019, and aims to consult on a minded-to decision and draft impact assessment in mid-2020 and to publish a decision in early 2021.

The target implementation date for these changes is 2023 and consequently has no impact on 2021-22 tariffs or this forecast.

Charging methodology changes

There have been no changes that have been approved to the charging methodology since January when we published the Final 2020/21 tariffs.

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[2] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

[3] https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision

There are a number of ‘in-flight’ proposals to change the charging methodologies. These are summarised on the inflight modifications table 19.

Changes to the methodology due to new price control period RIIO-2

In accordance with the CUSC, at the start of the next price control in April 2021, various aspects of the TNUoS methodology are required to be revised and updated based on new data for the price-control.

What might change under RIIO-2?

Several parameters which affect the locational and non-locational elements of the tariff must be recalculated and reset in preparation for the new price control, to apply from 1 April 2021. They are listed in the table below.

The two CUSC Modifications have been raised to change the generation zones and the underlying methodology used to establish them:

- CMP324 - 'Generation Zones – changes for RIIO-T2'
- CMP325 - 'Rezoning – CMP324 expansion'

When will we found out more?

Input data for the recalculation of parameters is required from a number of sources, including the TO’s and the Ofgem RIIO-2 determinations, and will become available at different stages over the course of this year. We have begun the process of requesting and analysing the TO data required to recalculate RIIO-2 parameters. It is anticipated that we will include indicative parameters, based on the information available later this year, in the 5 Year View.

Assumptions about RIIO-2

The key components which need to be addressed at the price control and how they are treated in this forecast are outlined in the following table.

A. RIIO-2 Assumptions

Component	Description	Assumptions for 2021/22 onwards
Maximum Allowed Revenue	The MAR for onshore TOs in the new price control period will be determined during the negotiations up to the start of the price control period.	**Our assumption in these tariffs is based on current onshore TOs’ MAR forecast under relevant STC procedures.**
Generation zones	There are currently 27 generation zones. At the start of the next price control, there is a requirement to rezone to ensure the spread of nodal prices within a zone is +/- £1/kW, while maintaining stability of generation tariffs.	**Our assumption in these tariffs is that the number of generation zones remains at 27. In the section “sensitivity to changes”, we have also included alternative generation tariffs under alternative zoning criteria (14 zones and 48 zones)[4].**

[4] https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp324-cmp325-generation-zones-changes-riio

Component	Description	Assumptions for 2021/22 onwards
Expansion Constant and Factors	The expansion constant and expansion factors need to be recalculated by the start of RIIO-2, based on TOs' business plans and costs of investments. The expansion constant represents the cost of moving 1MW, 1km using 400kV OHL line. The expansion factors represent how many times more expensive moving 1MW, 1km is using different voltages and types of circuit.	**Our assumption in these tariffs is that the expansion constant continues to increase by RPI as per the CUSC, and that the expansion factors are unchanged.**
Locational Onshore Security Factor	The security factor is currently 1.8. This will be recalculated by the start of RIIO-2 period.	**Our assumption in these tariffs is the security factor remains as 1.8.**
Local Substation Tariffs	Local Substation tariffs will be recalculated in preparation for the start of the price control based on TO asset costs.	**Our assumption in these tariffs is that offshore tariffs increase by RPI.**
Offshore Local tariffs	The elements for the offshore tariffs will be recalculated in preparation for the start of the price control, based on updated forecasts of OFTO revenue, and adjusting for differences in actual OFTO revenue to forecast revenue in RIIO-T1.	**The offshore tariffs have been recalculated to adjust for differences in actual OFTO revenue to forecast revenue in RIIO-T1.** **The only element in the calculation which has not yet been recalculated is the Offshore substation discount, our assumption for these tariffs is that the existing discount increases by RPI.**
Avoided GSP Infrastructure Credit (AGIC)	The AGIC is a component of the Embedded Export Tariff, paid to 'exporting demand' at the time of Triad. It will be recalculated based on up to 20 schemes from the RIIO-2 price-control period.	**Our assumption in these tariffs is that the AGIC increases by RPI.**

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Generation tariffs

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

1. Generation tariffs summary

This section summarises the forecasted generation tariffs for 2021/22 and how these tariffs were calculated

For this forecast we have modelled the tariffs based on Ofgem's final decision for the Targeted Charging Review (TCR) where the Transmission Generation Residual (TGR) has been greatly increased, so become less negative. This would increase the amount generators pay for TNUoS.

As part of our modelling of the TGR, we have assumed that local onshore and offshore tariffs are not included in the European €2.50/MWh cap as proposed under CMP317, which has resulted in the increase of the generation residual.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2020/21 Final	2021/22 March	Change since last forecast
Residual	- 4.849145	- 0.365971	4.483175
Average Generation Tariff*	5.299849	10.690216	5.390367

*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.

Average generation tariffs have increased by £5.39/kW. This is mainly driven by the TCR change. The generation residual is still negative to ensure Generation Tariffs are compliant with European Legislation, which requires total TNUoS recovery from generators to be within the range of €0-2.50/MWh on average. These average tariffs include revenues from local tariffs.

We have assumed that local onshore and offshore tariffs are not included in the European €2.50/MWh cap, as proposed under CMP317. This has resulted in the increase of the generation residual.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2021/22. 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)		

Table 2 Generation wider tariffs

		Tariffs (£/kW)						
						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.197137	19.172483	17.950319	- 0.365971	33.529408	37.119471	25.253341
2	East Aberdeenshire	2.511181	13.607765	17.950319	- 0.365971	27.391677	30.981741	23.027454
3	Western Highlands	3.950144	17.372717	17.282636	- 0.365971	31.308455	34.764983	23.865752
4	Skye and Lochalsh	- 0.681317	17.372717	19.124253	- 0.365971	28.150288	31.975139	25.707369
5	Eastern Grampian and Tayside	4.846430	13.568642	15.191140	- 0.365971	27.488285	30.526513	20.252626
6	Central Grampian	5.097666	14.596163	16.321073	- 0.365971	29.465484	32.729698	21.793567
7	Argyll	4.424699	12.589821	25.685573	- 0.365971	34.679043	39.816158	30.355530
8	The Trossachs	4.592597	12.589821	14.071720	- 0.365971	25.555859	28.370203	18.741677
9	Stirlingshire and Fife	2.535133	10.949612	12.737119	- 0.365971	21.118547	23.665971	16.750993
10	South West Scotlands	3.770178	11.448876	13.104778	- 0.365971	23.047130	25.668086	17.318357
11	Lothian and Borders	2.759209	11.448876	6.339219	- 0.365971	16.623714	17.891558	10.552798
12	Solway and Cheviot	2.030670	7.368174	7.326190	- 0.365971	13.420190	14.885428	9.907489
13	North East England	3.809489	5.505149	4.552398	- 0.365971	11.489556	12.400035	6.388487
14	North Lancashire and The Lakes	1.728953	5.505149	1.362447	- 0.365971	6.857059	7.129548	3.198536
15	South Lancashire, Yorkshire and Humber	4.564428	1.629072	0.333682	- 0.365971	5.768660	5.835397	0.619340
16	North Midlands and North Wales	3.577651	- 0.031239	-	- 0.365971	3.186689	3.186689	- 0.378467
17	South Lincolnshire and North Norfolk	1.835505	0.484528	-	- 0.365971	1.857156	1.857156	- 0.172160
18	Mid Wales and The Midlands	1.423969	0.869821	-	- 0.365971	1.753855	1.753855	- 0.018043
19	Anglesey and Snowdon	5.690940	- 0.559953	-	- 0.365971	4.877007	4.877007	- 0.589952
20	Pembrokeshire	9.703186	- 4.852024	-	- 0.365971	5.455596	5.455596	- 2.306781
21	South Wales & Gloucester	6.271503	- 4.985305	-	- 0.365971	1.917288	1.917288	- 2.360093
22	Cotswold	2.818669	3.217134	- 8.254863	- 0.365971	- 1.577485	- 3.228458	- 7.333980
23	Central London	- 5.928025	3.217134	- 7.511878	- 0.365971	- 9.729791	- 11.232167	- 6.590995
24	Essex and Kent	- 4.031931	3.217134	-	- 0.365971	- 1.824195	- 1.824195	0.920883
25	Oxfordshire, Surrey and Sussex	- 0.724719	- 2.360703	-	- 0.365971	- 2.979252	- 2.979252	- 1.310252
26	Somerset and Wessex	- 1.621570	- 3.243676	-	- 0.365971	- 4.582482	- 4.582482	- 1.663441
27	West Devon and Cornwall	- 0.089279	- 5.863301	-	- 0.365971	- 5.145891	- 5.145891	- 2.711291

The 80% and 40% ALFs used in this table for the Conventional Carbon, Conventional Low Carbon and Intermittent example tariffs are for illustration only. Tariffs for individual generators are calculated using their own ALF.

3. Changes since the previous generation tariffs forecast

The following section provides details of the wider and local generation tariffs in March forecast for 2021/22 and explains how these have changed since the 2020/21 Final Tariffs.

Generation wider zonal tariffs

The next table and chart show the changes in wider generation TNUoS tariffs since the January 2020/21 Final Tariffs.

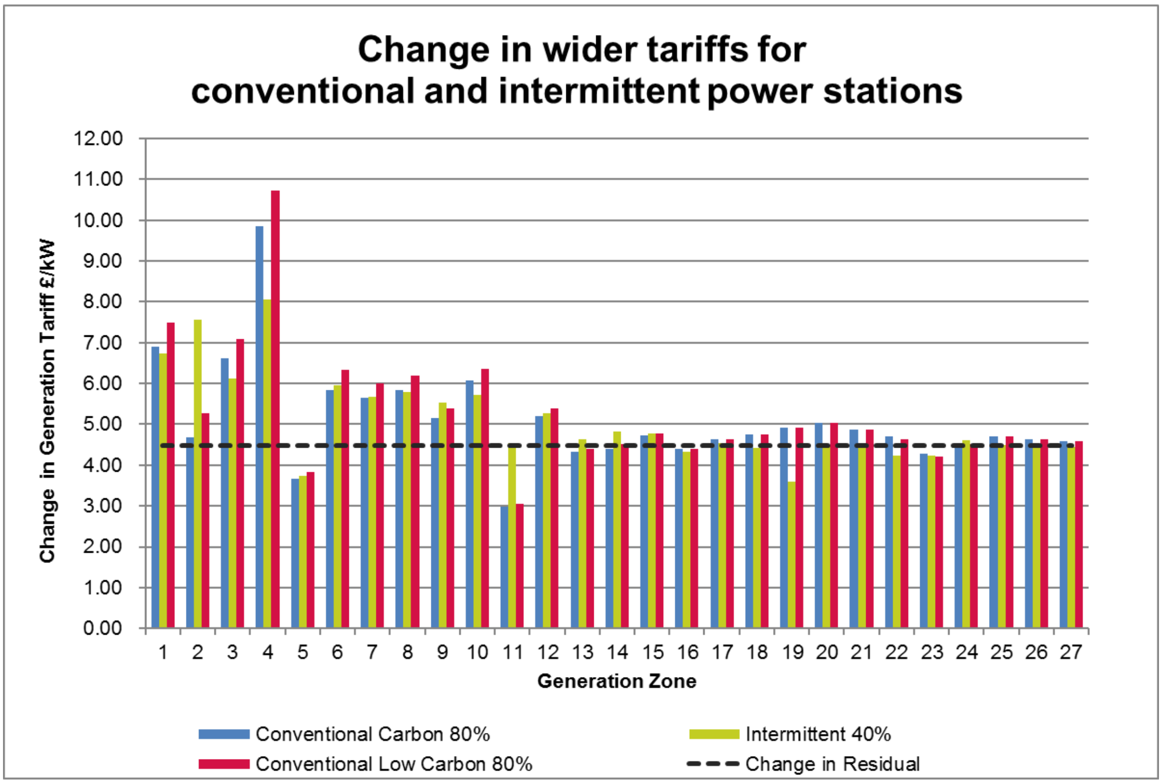
The table and chart below show the change in the example Conventional Carbon, Conventional Low Carbon and Intermittent tariffs. The Conventional tariffs use a load factor of 80%, and the Intermittent tariffs use a 40% load factor as an example.

The Generation tariffs in the below table include the potential impact of the TCR, where the TGR has become less negative due to the exclusion of the local tariffs from the European €2.50 cap. The specific mechanism to implement TGR change, is still being developed by the CMP317/327 workgroup. We will refine the methodology further based on the progress of the workgroup discussion and the final decision from the Authority.

Table 3 Generation wider tariff changes

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			
Zone	Zone Name	2020/21 Final	2021/22 March	Change	2020/21 Final	2021/22 March	Change	2020/21 Final	2021/22 March	Change	Change in Residual
1	North Scotland	26.619468	33.529408	6.909940	29.622230	37.119471	7.497241	18.515302	25.253341	6.738040	4.483175
2	East Aberdeenshire	22.710569	27.391677	4.681109	25.713331	30.981741	5.268410	15.472612	23.027454	7.554842	4.483175
3	Western Highlands	24.702272	31.308455	6.606183	27.665928	34.764983	7.099055	17.740395	23.865752	6.125357	4.483175
4	Skye and Lochalsh	18.292988	28.150288	9.857300	21.239874	31.975139	10.735265	17.656545	25.707369	8.050824	4.483175
5	Eastern Grampian and Tayside	23.832192	27.488285	3.656093	26.688798	30.526513	3.837714	16.522908	20.252626	3.729718	4.483175
6	Central Grampian	23.624199	29.465484	5.841284	26.405233	32.729698	6.324466	15.843052	21.793567	5.950515	4.483175
7	Argyll	29.023388	34.679043	5.655655	33.822751	39.816158	5.993407	24.684850	30.355530	5.670680	4.483175
8	The Trossachs	19.724644	25.555859	5.831215	22.179494	28.370203	6.190709	12.962289	18.741677	5.779388	4.483175
9	Stirlingshire and Fife	15.975685	21.118547	5.142862	18.266766	23.665971	5.399205	11.212455	16.750993	5.538538	4.483175
10	South West Scotlands	16.978384	23.047130	6.068747	19.303483	25.668086	6.364602	11.608057	17.318357	5.710300	4.483175
11	Lothian and Borders	13.631868	16.623714	2.991846	14.838249	17.891558	3.053308	6.014463	10.552798	4.538335	4.483175
12	Solway and Cheviot	8.209692	13.420190	5.210498	9.495786	14.885428	5.389642	4.639289	9.907489	5.268200	4.483175
13	North East England	7.156004	11.489556	4.333552	8.007850	12.400035	4.392185	1.754228	6.388487	4.634258	4.483175
14	North Lancashire and The Lakes	2.448012	6.857059	4.409047	2.622236	7.129548	4.507312	- 1.633883	3.198536	4.832418	4.483175
15	South Lancashire, Yorkshire and Humber	1.031415	5.768660	4.737245	1.058120	5.835397	4.777276	- 4.144802	0.619340	4.764142	4.483175
16	North Midlands and North Wales	- 1.199383	3.186689	4.386072	- 1.199383	3.186689	4.386072	- 4.706723	- 0.378467	4.328256	4.483175
17	South Lincolnshire and North Norfolk	- 2.777867	1.857156	4.635023	- 2.777867	1.857156	4.635023	- 4.699969	- 0.172160	4.527809	4.483175
18	Mid Wales and The Midlands	- 2.993760	1.753855	4.747615	- 2.993760	1.753855	4.747615	- 4.435867	- 0.018043	4.417825	4.483175
19	Anglesey and Snowdon	- 0.051525	4.877007	4.928532	- 0.051525	4.877007	4.928532	- 4.188589	- 0.589952	3.598637	4.483175
20	Pembrokeshire	0.411985	5.455596	5.043611	0.411985	5.455596	5.043611	- 6.776913	- 2.306781	4.470132	4.483175
21	South Wales & Gloucester	- 2.957486	1.917288	4.874774	- 2.957486	1.917288	4.874774	- 6.825638	- 2.360093	4.465545	4.483175
22	Cotswold	- 6.290867	- 1.577485	4.713382	- 7.867996	- 3.228458	4.639538	-11.573771	- 7.333980	4.239790	4.483175
23	Central London	-14.011179	- 9.729791	4.281388	-15.439154	-11.232167	4.206987	-10.828000	- 6.590995	4.237004	4.483175
24	Essex and Kent	- 6.334062	- 1.824195	4.509867	- 6.334062	- 1.824195	4.509867	- 3.688125	0.920883	4.609007	4.483175
25	Oxfordshire, Surrey and Sussex	- 7.675801	- 2.979252	4.696549	- 7.675801	- 2.979252	4.696549	- 5.795735	- 1.310252	4.485483	4.483175
26	Somerset and Wessex	- 9.218972	- 4.582482	4.636490	- 9.218972	- 4.582482	4.636490	- 6.135783	- 1.663441	4.472342	4.483175
27	West Devon and Cornwall	- 9.738041	- 5.145891	4.592150	- 9.738041	- 5.145891	4.592150	- 7.162819	- 2.711291	4.451527	4.483175

Figure 1 Variation in generation zonal tariffs



As you can see from the figure above, all generation zones have seen an increase in the generation tariffs. This is mainly driven by the increase in residual due to the implementation of the TCR.

There is some deviation between zones driven by the locational updates, which include circuit and locational generation and demand updates. This impacts flows on the network causing changes in the locational element of the tariffs; this resulted in greater increases in the north.

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 the price control based on TO asset costs and then inflated each year by the average May to October RPI for the rest of the price control period.

For this forecast, we have applied the RPI to the current substation tariffs. We will further refine the value throughout the year with the latest available information.

Table 4 Local substation tariffs

2021/22 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.209048	0.119589	0.086167
<1320 MW	Redundancy	0.460515	0.284924	0.207219
>=1320 MW	No redundancy	n/a	0.374965	0.271175
>=1320 MW	Redundancy	n/a	0.615595	0.449334

5. Onshore local circuit tariffs

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

Onshore local circuit tariffs have been updated with the latest RPI forecast, and for most users, the changes are minimal since the 2020/21 Final Tariffs. Onshore local circuit tariffs are listed in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.723176	Dunhill	1.491347	Luichart	0.598907
Aberdeen Bay	2.714789	Dunlaw Extension	1.571780	Marchwood	0.397364
Achruach	-2.661502	Edinbane	7.128354	Mark Hill	0.911649
Aigas	0.680979	Ewe Hill	2.534163	Middle Muir	2.063874
An Suidhe	-0.998034	Fallago	0.453309	Middleton	0.154649
Arecleoch	2.162533	Farr	3.712344	Millennium Wind	1.901602
Baglan Bay	0.792284	Fernoch	4.579981	Moffat	0.197354
Beinneun Wind Farm	1.563856	Ffestiniogg	0.263425	Mossford	2.999728
Bhlaraidh Wind Farm	0.672259	Finlarig	0.333395	Nant	- 1.279220
Black Hill	1.616991	Foyers	0.304988	Necton	- 0.368537
Black Law	1.819385	Galawhistle	3.643300	New Deer	0.784018
BlackCraig Wind Farm	6.554480	Glendoe	1.915221	Rhigos	0.107677
BlackLaw Extension	3.858241	Glenglass	5.009818	Rocksavage	0.018429
Clyde (North)	0.114186	Glen Kyllachy	- 0.476279	Saltend	0.018065
Clyde (South)	0.132051	Gordonbush	0.188836	South Humber Bank	0.430734
Corriegarth	3.016432	Griffin Wind	10.113396	Spalding	0.295207
Corriemoillie	1.734082	Hadyard Hill	2.881961	Strathbrora	0.057532
Coryton	0.051463	Harestanes	2.631138	Strathy Wind	1.906648
Cruachan	1.900064	Hartlepool	0.213963	Stronelairg	1.118917
Crystal Rig	0.142250	Invergarry	0.381023	Wester Dod	0.496549
Culligran	1.804612	Kilgallioch	1.095821	Whitelee	0.110503
Deanie	2.964719	Kilmorack	0.205632	Whitelee Extension	0.307198
Dersalloch	2.508079	Kype Muir	1.544378		
Dinorwig	2.498158	Langage	0.684805		
Dorenell	2.185123	Limekilns	0.635038		
Dumnaglass	1.180113	Lochay	0.381023		

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 made to the generators. For more information please see CUSC sections 2.14.4, 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
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
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	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes
Coalburn 132kV	Kype Muir 132kV	17km cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km cable	13km OHL	Middle Muir
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
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

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 price review 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.

Please note that these offshore tariffs have been recalculated, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting. The only element in the calculation which has not yet been recalculated is the Offshore substation discount, our assumption for these tariffs is that the existing discount is increased by RPI, an indicative value will be calculated and incorporated in our future forecasts once input data is available.

Offshore local generation tariffs associated with projects due to transfer in 2020/21 will be confirmed once asset transfer has taken place.

Table 7 Offshore local tariffs 2021/22

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	9.017025	46.992324	1.166884
Burbo Bank	11.266389	21.536282	-
Dudgeon	16.526172	25.730618	-
Galloper	16.841406	26.439601	-
Greater Gabbard	16.704427	38.299182	-
Gunfleet	19.538772	17.904168	3.346392
Gwynt Y Mor	20.792270	20.442180	-
Humber Gateway	12.171630	27.671602	-
Lincs	17.322768	67.625980	-
London Array	11.689926	39.663613	-
Ormonde	27.473019	51.125012	0.407423
Race Bank	10.122919	27.752994	-
Robin Rigg	- 0.478335	34.072272	10.916539
Robin Rigg West	- 0.478335	34.072272	10.916539
Sheringham Shoal	25.734868	30.165108	0.655701
Thanet	19.655822	36.597055	0.881020
Walney 1	23.757356	47.252502	-
Walney 2	22.123519	44.774026	-
West of Duddon Sands	9.152286	45.020395	-
Westermost Rough	18.606280	31.453270	-

3

Demand tariffs

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

7. Demand tariffs summary

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

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

Table 8 Summary of demand tariffs

HH Tariffs	2020/21 Final	2021/22 March	Change
Average Tariff (£/kW)	49.564393	45.257946	- 4.306447
Residual (£/kW)	51.881473	46.816636	- 5.064837
EET	**2020/21 Final**	**2021/22 March**	**Change**
Average Tariff (£/kW)	2.371818	2.516587	0.144769
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	3.416495	3.513565	0.097070
Embedded Export Volume (GW)	7.230000	6.819955	- 0.410045
Total Credit (£m)	17.156120	17.163009	0.006890
NHH Tariffs	**2020/21 Final**	**2021/22 March**	**Change**
Average (p/kWh)	6.023208	5.716624	- 0.306584

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	15.013659	2.044827	-
2	Southern Scotland	22.823089	2.942453	-
3	Northern	35.205172	4.389070	-
4	North West	41.853367	5.306145	-
5	Yorkshire	42.705231	5.255794	-
6	N Wales & Mersey	44.132320	5.508067	0.829249
7	East Midlands	46.383978	5.907568	3.080907
8	Midlands	47.942227	6.197093	4.639156
9	Eastern	48.577436	6.612843	5.274364
10	South Wales	45.290920	5.253280	1.987848
11	South East	51.480819	7.128290	8.177748
12	London	54.446552	5.488955	11.143481
13	Southern	52.819783	6.796496	9.516711
14	South Western	51.987570	7.218883	8.684499

Residual charge for demand:	46.816636

8. Changes since the 2020/21 Final Tariffs

Demand tariffs have been forecasted to decrease significantly, the main impact being the implementation of TGR and the generation revenue and tariffs increasing. It is expected to reduce the amount of revenue to be collected through demand.

Additionally, the HH demand charging base has decreased slightly and the locational elements, including locational demand (Week24 data) has been updated have a slight impact on demand tariffs. Though the main driver is the reduction in revenue to be collected through demand.

The average HH gross tariff is forecast at £45.26/kW, a reduction of £4.30/kW compared to the 2020/21 Final Tariffs. The average NHH tariff is forecast at 5.71p/kWh, a decrease of 0.30p/kWh.

According to the ESO licence, the Small Generator Discount (SGD) no this will end 31 March 2021 (see sensitivities section for further details). As such the figures shown in this forecast do not include the Small Generator Discount levy.

There is a decrease in the Embedded Export Volume of 0.41GW to 6.82GW compared to the 2020/21 Final Tariffs, with a slight increase to the AGIC of £0.10/kW to £3.51/kW. The overall impact of these changes gives a £0.14/kW increase of the average EET to £2.52/kW.

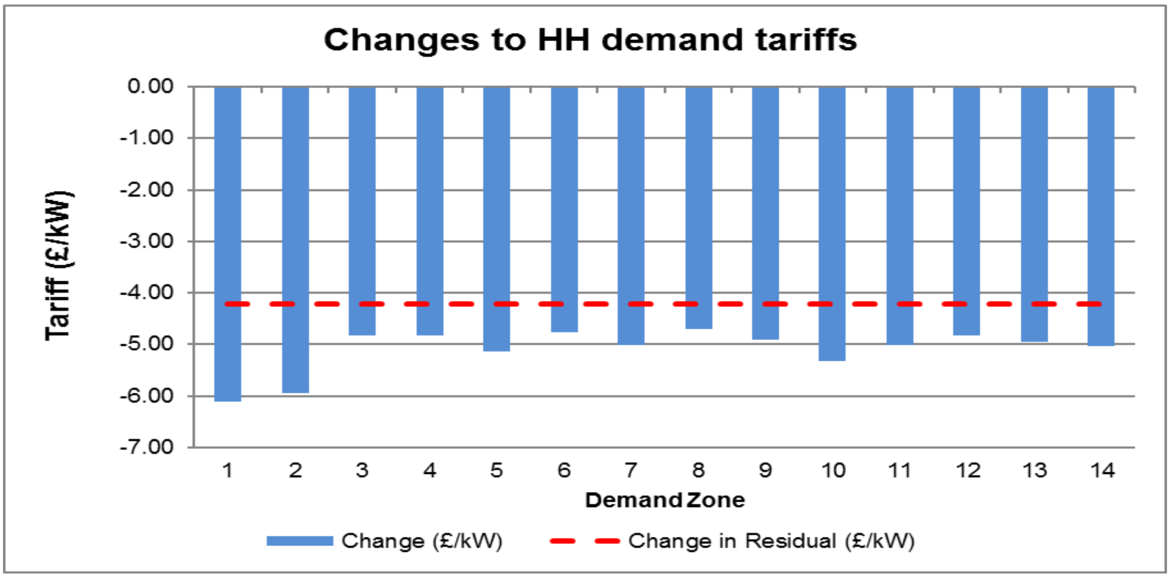
9. Half-Hourly demand tariffs

This table and chart show the forecast gross HH demand tariffs for 2021/22 compared to the 2020/21 Final Tariffs.

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2020/21 Final (£/kW)	2021/22 March (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	21.126849	15.013659	- 6.113190	- 4.215009
2	Southern Scotland	28.760295	22.823089	- 5.937206	- 4.215009
3	Northern	40.022002	35.205172	- 4.816830	- 4.215009
4	North West	46.674676	41.853367	- 4.821309	- 4.215009
5	Yorkshire	47.834680	42.705231	- 5.129449	- 4.215009
6	N Wales & Mersey	48.904955	44.132320	- 4.772635	- 4.215009
7	East Midlands	51.387929	46.383978	- 5.003951	- 4.215009
8	Midlands	52.648445	47.942227	- 4.706218	- 4.215009
9	Eastern	53.488450	48.577436	- 4.911014	- 4.215009
10	South Wales	50.613794	45.290920	- 5.322874	- 4.215009
11	South East	56.501849	51.480819	- 5.021030	- 4.215009
12	London	59.267002	54.446552	- 4.820450	- 4.215009
13	Southern	57.772417	52.819783	- 4.952634	- 4.215009
14	South Western	57.020402	51.987570	- 5.032832	- 4.215009

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariff have decreased across all zones. The decrease is spread relatively equal across the 14 zones due to the large reduction of the demand residual, which has resulted from the increase of the generation residual (i.e. it became less negative) with a slightly higher reduction seen in zones 1 & 2 due to the impact of the locational elements that have been updated.

The forecasted level of gross HH chargeable demand has decreased by 0.2GW in comparison with the 2020/21 Final Tariffs and is currently forecast at 19.4GW.

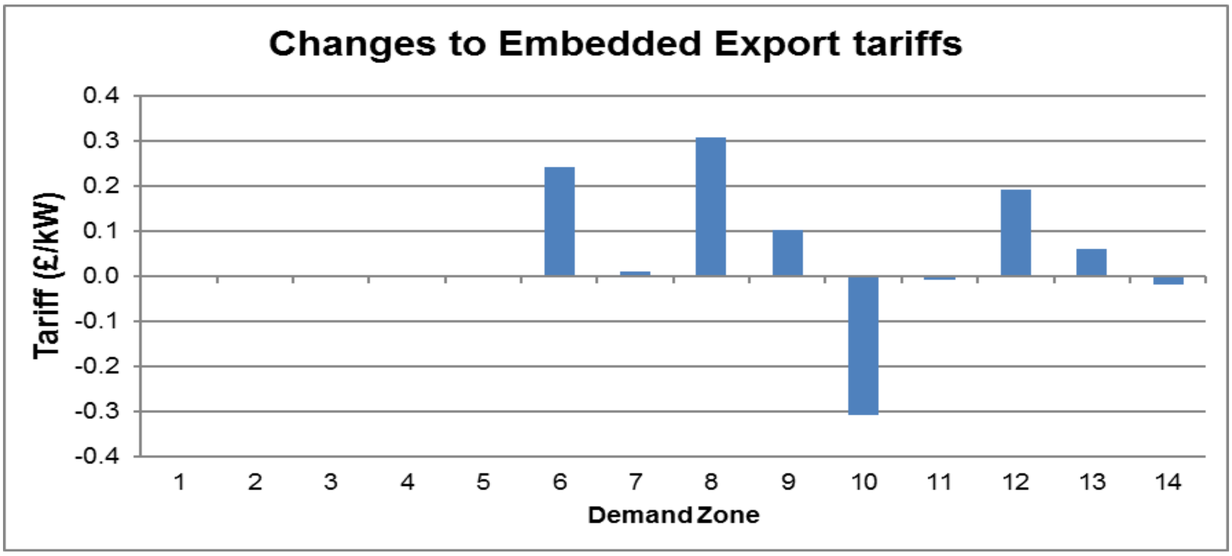
10. Embedded Export Tariffs (EET)

The next table and figure show the forecast 2021/22 EET compared to the 2020/21 Final Tariffs.

Table 11 Embedded Export Tariffs

Zone	Zone Name	2020/21 Final (£/kW)	2021/22 March (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.587601	0.829249	0.241648
7	East Midlands	3.070575	3.080907	0.010332
8	Midlands	4.331091	4.639156	0.308065
9	Eastern	5.171096	5.274364	0.103268
10	South Wales	2.296440	1.987848	- 0.308592
11	South East	8.184495	8.177748	- 0.006747
12	London	10.949648	11.143481	0.193833
13	Southern	9.455063	9.516711	0.061648
14	South Western	8.703048	8.684499	- 0.018549

Figure 3 Embedded export tariff changes



In this forecast for 2021/22, EET charging base has dropped down to 6.8GW a reduction of 0.4GW, with the forecasted EET revenue increasing marginally at around the £17.16m mark. Subsequently there has been a small increase in the average EET forecast for 2021/22 compared to the 2020/21 Final tariffs, with an increase of £0.14/kW to £2.52. There has been a slight increase in the AGIC (Avoided Grid Supply Point Infrastructure Credit) based on forecasted RPI for 2021/22.

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

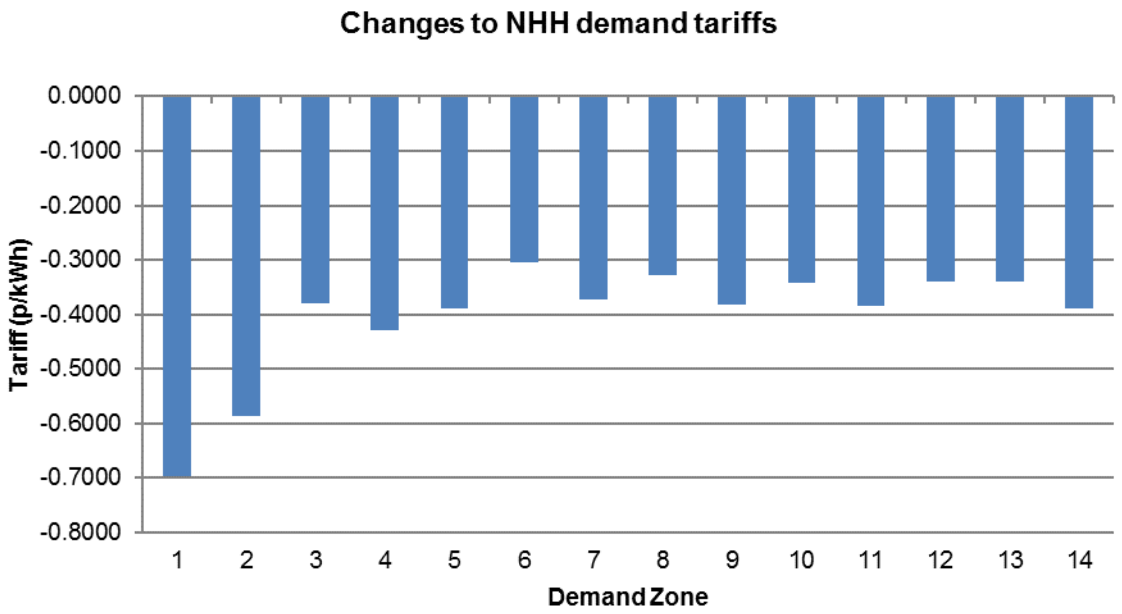
11. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2021/22 forecast and the 2020/21 Final Tariffs.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2020/21 Final (p/kWh)	2021/22 March (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.742642	2.044827	- 0.697815
2	Southern Scotland	3.528995	2.942453	- 0.586542
3	Northern	4.768367	4.389070	- 0.379297
4	North West	5.735191	5.306145	- 0.429046
5	Yorkshire	5.645414	5.255794	- 0.389620
6	N Wales & Mersey	5.811644	5.508067	- 0.303577
7	East Midlands	6.281123	5.907568	- 0.373555
8	Midlands	6.525494	6.197093	- 0.328401
9	Eastern	6.994220	6.612843	- 0.381377
10	South Wales	5.594905	5.253280	- 0.341625
11	South East	7.511337	7.128290	- 0.383047
12	London	5.828242	5.488955	- 0.339287
13	Southern	7.136303	6.796496	- 0.339807
14	South Western	7.608806	7.218883	- 0.389923

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2021/22 is forecasted at 5.72p/kWh, which is a 0.31p/kWh reduction compared to the 2020/21 Final Tariffs. The main reason for the reduction is the implementation of the TCR, where the generation residual has increased, resulting in more revenue being collected from generators. This has caused the revenue to be collected form demand to decrease.

As you can see form the above figure, the tariffs across all zones have decreased; zones 1 & 2 have reduced the greatest (0.60p - 0.70p/kWh) with the remaining zones decreasing the remaining zones adjusted to around 0.30 - 0.40p/kWh.

4

Updates to revenue and the charging model since the last forecast

Since the 2020/21 Final Tariffs were published, we have updated allowed revenue forecast for Transmission Owners, the generation background, the zonal demand charging base, and RPI.

For details about quarterly updates to TNUoS parameters, please see Appendix J.

12. Changes affecting the locational element of tariffs

The 2021/22 locational element of generation and demand tariffs will be based upon:

- Contracted generation and nodal demand as of 31 October 2020;
- Local and MITS circuits as set in the Draft Tariffs; and
- Inflation, which decreases the expansion constant

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2021/22 period, which can be found on the TEC register.[5] The contracted TEC volumes are based on the February 2020 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. We will forecast our best view of modelled TEC until 31 October 2020, after which we must use the TEC as published in the TEC register as of 31 October 2020, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2021/22 and are liable to pay generation TNUoS charges. We will continue to review our forecast of Chargeable TEC until the Final Tariffs are published in January 2021.

Table 13 Contracted TEC

	2020/21	2021/22 Tariffs			
Generation (GW)	Final	March	August	Draft	Final
Contracted TEC	84.9	93.6			
Modelled Best View TEC	84.9	85.8			
Chargeable TEC	70.7	76.8			

13. Adjustments for interconnectors

When modelling flows on the transmission system, 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 2021/22 in the interconnector register as of February 2020.

[5] 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
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
BritNed	Grain 400kV	Netherlands	24	0	1200	0
Belgium Interconnector (Nemo)	Richborough 400kV	Belgium	24	0	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2 Interconnector	Chilling 400KV Substation	France	26	0	1100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	637	0
NS Link	Blyth	Norway	13	0	1400	0

14. Expansion Constant and RPI

The expansion constant is the annuitised value of the cost required to transport 1 MW over 1 km. The 2021/22 Expansion Constant is forecast to be £ 15.367047 /MWkm. This value will be updated in line with the average May to October RPI, and will be finalised with the outturn value by the Final Tariffs.

The expansion constant is also dependent on the annuity factor, which will be reviewed as part of the RIIO-T2 parameter reset. We will update this value, along with other parameters, in the August 5 year tariff view.

15. Onshore substation

Local onshore substation tariffs are indexed by the average May to October RPI, and will be updated to take into account the actual RPI.

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 Offshore Transmission Owner. These tariffs have been recalculated, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting These recalculations use the latest forecast of the relevant inflation terms.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other revenue (for example, Network Innovation Competition) are also collected from network users via TNUoS. The total amount recovered is adjusted for interconnector revenue recovery or redistribution. The initial Tariff revenues have been based on TOs forecast of their RIIO-T2 revenue, and thus carry greater uncertainty. The revenue figures will be updated by November Draft tariffs and finalised by January 2021 in the Final tariffs.

For more details on TOs allowed revenues, please refer to Appendix G.

Table 15 Allowed revenues

£m Nominal	2021/22 TNUoS Revenue March Forecast	August Forecast	Nov Draft	Jan Final
National Grid Electricity Transmission				
Price controlled revenue	*1,754.9*			
Less income from connections				
NGET Income from TNUoS	**1,754.9**			
Scottish Power Transmission				
Price controlled revenue	*389.5*			
Less income from connections	*12.7*			
SPT Income from TNUoS	**376.7**			
SHE Transmission				
Price controlled revenue	*377.5*			
Less income from connections	*3.4*			
SHE Income from TNUoS	**374.0**			
National Grid Electricity System Operator				
Other Pass-through from TNUoS	**17.4**			
Offshore (plus IFA contribution / allowance)	**529.9**			
Total to Collect from TNUoS	**3,053.1**			

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The revenue to be collected from generators and demand suppliers will be updated throughout quarterly tariff forecasts, and will be finalised in the Final Tariffs.

The "EU 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 dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin of 16% is also applied to reflect revenue and output forecasting accuracy. This revenue figure is normally referred to as the "EU gen cap" and will be locked down in the August tariff forecast.

TCR implementation - TNUoS generation residual (TGR) change

On 21 November 2019, the Authority 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. This includes, among other changes, the removal of generation residual, which will take effect from April 2021.

This change is managed under CUSC modification proposals CMP317/327, which seeks to establish which charges are, and are not in scope of the EU gen cap. There are various options that are being developed by the workgroup. In this forecast, we use the original CMP327 proposal to illustrate the likely impacts on TNUoS tariffs, if the option is approved and implemented by 2021/22.

Under the CMP327 original proposal, charges that are collected via generator local tariffs (including onshore and offshore local substation charges, and onshore and offshore local circuit charges), will be excluded from the EU gen cap. Therefore, the EU gen cap is only applicable for charges that are collected via generation wider tariffs.

Due to this TGR change, revenue collected from generators (via wider tariffs and local tariffs) will be much higher compared to 2020/21. In this forecast, generation revenue is forecast at £820.6m, an increase of £445.7m from £374.9m for 2020/21.

Exchange Rate

As prescribed by the TNUoS charging methodology, the exchange rate for 2021/22 will be taken from the Economic and Fiscal Outlook, published by the Office of Budgetary Responsibility in July 2020. In this forecast, we continue using 2020/21 value, which is €1.119217/£.

Generation Output

The forecast output of generation has stayed the same at 199.8TWh. This figure is the average of the four scenarios in 2019 Future Energy Scenarios publication and will be updated with the latest figure by August forecast.

Error Margin

The error margin remains unchanged from 2020/21 at 16%.

The parameters used to calculate the proportions of revenue collected from generation and demand are shown in the table below.

Table 16 Generation and demand revenue proportions

		2021/22 Tariffs			
Code	**Revenue**	**March**	**August**	**Draft**	**Final**
CAPEC	Limit on generation tariff (€/MWh)	2.5			
y	Error Margin	16.0%			
ER	Exchange Rate (€/£)	1.1			
MAR	Total Revenue (£m)	3,053.1			
GO	Generation Output (TWh)	199.8			
	Wider locational generator Revenue (£m)	403.0			
	Charges on assets required for connection (£m)	445.6			
G	% of revenue from generation	26.9%			
D	% of revenue from demand	73.1%			
G.R	Revenue recovered from generation (£m)	820.6			
D.R	Revenue recovered from demand (£m)	2,232.6			

19. Charging bases for 2020/21

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 is 76.8GW due and based on our internal view of what generation we expect to connect next financial year.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated to follow forecasted out-turn for 2021/22. Comparisons will be drawn in the forthcoming 2021/22 reports on updates and revisions to these forecasts and the impact they have.

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 (August 2014-March 2019)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

Overall, we assume that recent historical trends in steadily declining demand volumes will continue due to several factors, including the growth in distributed generation and "behind the meter" microgeneration. But due to the increase in electric vehicles and heat pumps, demand will begin to gradually increase again in future years.

Table 17 Charging bases

	2021/22 Tariffs			
Charging Bases	**March**	**August**	**Draft**	**Final**
Generation (GW)	70.7			
NHH Demand (4pm-7pm TWh)	24.0			
Net Charging				
Total Average Net Triad (GW)	43.2			
HH Demand Average Net Triad (GW)	12.6			
Gross charging				
Total Average Gross Triad (GW)	50.0			
HH Demand Average Gross Triad (GW)	19.4			
Embedded Generation Export (GW)	6.8			

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2020/21 ALFs, based upon data from 2014/15 to 2018/19. ALFs are explained in more detail in Appendix E of this report, and the full list of power station ALFs are available on the National Grid ESO website.[6]

The ALFs that will apply to 2021/22 TNUoS Tariffs will be updated by November 2020.

21. Generation and demand residuals

The residual element of tariffs is calculated using the formulae below.

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

[6] https://www.nationalgrideso.com/document/157476/download

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

Where

- R_G is the generation residual 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)

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[7] and phased residual.

[7] Avoided Grid Supply Point Infrastructure Credit

Table 18 Residual components calculation

Component		2021/22 Tariffs March	August	Draft	Final
G	Proportion of revenue recovered from generation (%)	26.9%			
D	Proportion of revenue recovered from demand (%)	73.1%			
R	Total TNUoS revenue (£m)	3,053.1			
Generation Residual					
R_G	Generator residual tariff (£/kW)	- 0.4			
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	403.0			
O	Revenue recovered from offshore local tariffs (£m)	408.2			
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.5			
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.9			
B_G	Generator charging base (GW)	76.8			
Gross Demand Residual					
R_D	Demand residual tariff (£/kW)	46.8			
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	- 92.4			
EE	Amount to be paid to Embedded Export Tariffs (£m)	17.2			
B_D	Demand Gross charging base (GW)	50.0			

5

Sensitivities to change

Purpose

We are conscious that there are significant uncertainties with the charging methodologies. To help the industry to understand the potential implications of the ongoing proposed changes, we have undertaken further modelling around the methodology changes arising from Ofgem-led Targeted Charging Review, and potential CUSC modification to generation zoning methodology. These methodology changes are being developed by the workgroups, and each contains a variety of options. In this report, we have included some indicative tariffs that reflect a few of the options that are being assessed by the workgroups.

The sensitivity analysis that we undertook for 2021/22 tariffs include -

1. A scenario where TNUoS demand residual (TDR) changes are implemented by 2021/22.
2. A scenario where Small Generator Discount (SGD) scheme is extended to 2021/22.
3. A scenario where generators are grouped into 14 zones (by DNO's areas).
4. A scenario where generators are grouped by the ± £1/kW nodal price range.

Caveats

The charging year 2021/22 is the first year in RIIO-T2 price control period, and a few TNUoS parameters are yet to be reset. In addition, the methodology is subject to changes including TCR and other ongoing CUSC modification proposals. All tariffs in this section are to illustrate mathematically how tariffs may evolve. In presenting certain sensitivities under certain CUSC mod options, it does not infer about our view of the future, likelihoods of certain scenarios or changes to policy.

Whilst every effort is made to ensure the accuracy of the information, it is subject to several estimates and forecasts, and may not bear relation to neither the indicative nor future tariffs National Grid Electricity System Operator will publish at a later date.

Sensitivity analysis

22. TNUoS demand residual (TDR) sensitivity

On 25th March 2020, we wrote to Ofgem requesting approval to withdraw CMP332[8] (Transmission Demand Residual bandings and allocation - TCR), and to defer the implementation date of TDR (originally planned for April 2021). Therefore, when forecasting 2021/22 tariffs, we did not consider TDR. We are however including a sensitivity case here, to illustrate the indicative demand tariffs, should TDR be implemented by April 2021 and the original CMP332 proposal is chosen. These tariffs are highly indicative, as neither the methodology nor the input data are fully known.

Under TDR, demand residual tariff (in £/kW and applied to Triad demand) will be replaced with a fixed p/site per day charge, and applied to final demand users. The indicative TDR charges is levied in p/site per day. The ESO will charge TDR to suppliers, for their final demand users.

[8] https://www.nationalgrideso.com/document/166236/download

Table S1 Indicative demand residual tariffs under TDR

Band	Consumption (GWh)	Consumption portion (%)	Revenue by Bands (£m)	Site Count	TDR Charge (£/Site)
Domestic	80620	33.60%	719.2	27800000	26
LV_NoMIC_1	1142	0.48%	10.2	715298	14
LV_NoMIC_2	4413	1.84%	39.4	536323	73
LV_NoMIC_3	5193	2.16%	46.3	268160	173
LV_NoMIC_4	15653	6.52%	139.6	268188	521
LV1	8904	3.71%	79.4	73131	1086
LV2	12011	5.01%	107.1	59237	1809
LV3	6818	2.84%	60.8	21649	2809
LV4	19050	7.94%	169.9	26904	6316
HV1	4648	1.94%	41.5	9165	4524
HV2	13104	5.46%	116.9	7462	15665
HV3	9156	3.82%	81.7	2680	30475
HV4	28674	11.95%	255.8	3407	75074
EHV1	167	0.07%	1.5	517	2878
EHV2	3949	1.65%	35.2	395	89182
EHV3	5093	2.12%	45.4	174	261083
EHV4	17610	7.34%	157.1	192	818176
Transmission connected	3699	1.54%	33.0	65	507600

Note:

LV – Low Voltage = less than 1 kV networks, i.e. 230/400 V.

HV – High Voltage = networks operating between 1 kV and 22 kV, i.e. 6.6 kV or 11 kV.

EHV – Extra High Voltage = networks operating above 22 kV, i.e. 33 kV or 66 kV.

MIC – Maximum Import Capacity.

Table S2 Demand locational tariffs under TDR

		Demand locational (floored)		
Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.000000	0.000000	0.000000
6	N Wales & Mersey	0.000000	0.000000	0.829249
7	East Midlands	0.000000	0.000000	3.080908
8	Midlands	1.125592	0.145496	4.639157
9	Eastern	1.760800	0.239698	5.274365
10	South Wales	0.000000	0.000000	1.987849
11	South East	4.664184	0.645826	8.177749
12	London	7.629917	0.769200	11.143482
13	Southern	6.003147	0.772445	9.516712
14	South Western	5.170934	0.718025	8.684499

23. Small generator discount (SGD) sensitivity

The Small Generator Discount is defined in National Grid's licence condition C13. This licence condition expires on 31 March 2021 Therefore, applicable generators will no longer receive the discount to their TNUoS tariffs. Similarly, there will be no additional charge added to demand tariffs to recover the cost of the scheme. The tariffs in this report do not include the Small Generator Discount.

On 24 January 2019, Ofgem published an Open letter[9] on their decision to extend the discount until 31 March 2021. Ofgem have been clear that the Small Generator Discount is linked to the Transmission Demand Residual (TDR) Reforms but it was made clear if the TDR reform was delayed beyond April 2021 the Small Generator Discount will not necessarily be extended. For this reason, we have not included the SGD in our base case for this report, but we have undertaken an analysis where the SGD extends to 2021/22.

If the Small Generator Discount is extended using the same methodology, we forecast

- The discount given to affected small generators to be £11.612666/kW
- The additional tariff to add to all demand tariffs:
  - HH: £0.716111/kW, and
  - NHH: 0.091407/kWh

Table S3 Small Generator Discount calculation

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	- 0.37
Demand Residual (£/kW)	D	46.82
Small Generator Discount (£/kW)	T = (G + D)/4	11.61
Forecast Small Generator Volume (kW)	V	3,085,040
2021/22 SGD cost (£)	V x T	35,825,539
Prior year reconcilation (£)	R	-
Total SGD Cost (£)	C = (V x T) - R	35,825,539
Total System Triad Demand (kW)	TD	50,027,892
Total HH Triad Demand (kW)	HHD	19,430,944
Total NHH Consumption (kWh)	NHHD	23,970,719,930
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.716111
Total Cost to HH Customers (£)	HHC = HHT * HHD	13,914,719
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.091407
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	21,910,821

The generator discount rate is subtracted from the applicable TNUoS tariff for affected generators. The HH and NHH rates are added to all demand tariffs.

[9] https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd_decision_letter_final.pdf

Table S4 Demand tariffs under SGD

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	15.729770	2.136234	0.000000
2	Southern Scotland	23.539200	3.033860	0.000000
3	Northern	35.921283	4.480477	0.000000
4	North West	42.569478	5.397552	0.000000
5	Yorkshire	43.421342	5.347201	0.000000
6	N Wales & Mersey	44.848431	5.599474	0.829249
7	East Midlands	47.100089	5.998975	3.080907
8	Midlands	48.658338	6.288500	4.639156
9	Eastern	49.293547	6.704250	5.274364
10	South Wales	46.007031	5.344687	1.987848
11	South East	52.196930	7.219697	8.177748
12	London	55.162663	5.580362	11.143481
13	Southern	53.535894	6.887903	9.516711
14	South Western	52.703681	7.310290	8.684499

Tariffs include small gen tariff of:	0.716111	0.091407

24. Generation zoning sensitivity

Under the CUSC, we undertake re-zoning prior to every price control, to capture network parameter/ topology changes, and the effect from long term "shift" in generation & demand patterns.

Costs of building and maintaining the transmission network are also reviewed by Ofgem at each of the price control period. the decision on financial parameters (e.g. rate of return, asset depreciation) will feed into TNUoS tariffs via the Expansion Constant (EC) calculation, and therefore also affect the re-zoning results.

The CUSC requires that re-zoning will be undertaken in such a way that minimises the adverse impact on Users. A CUSC modification proposal (CMP324/325) has been raised to review the existing re-zoning criteria, in order to achieve tariff stability & long-term investment signals against the backdrop of RIIO-T2 and Significant Code Review uncertainties.

This section looks at the effect of alternative zoning approach.

1) to group generators in the same DNO area into one generation zone;
2) to group generators that are within the same ±£1/kW nodal price range, into one zone.

The first approach leads to 14 generation zones; the second approach leads to 48 generation zones.

Table S5 Indicative generation wider tariffs under option 1 (14 zones)

		Tariffs (£/kW)				Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	Northern Scotland	3.338886	16.57932912	16.50331016	-0.20554	29.59946165	32.90012368	22.92950622
2	Southern Scotland	3.390889	11.26690478	10.10593083	-0.20554	20.28362238	22.30480854	14.40715716
3	Northern	3.813018	6.528988334	3.474333814	-0.20554	11.61014032	12.30500709	5.880393562
4	North West	1.57511	4.974845705	1.600107131	-0.20554	6.629537099	6.949558525	3.384509827
5	Yorkshire	4.588161	1.778121502	0.13245509	-0.20554	5.911086976	5.937577994	0.638168106
6	N Wales & Mersey	3.863046	-0.37978213	0	-0.20554	3.353684836	3.353684836	-0.357448436
7	East Midlands	3.381296	-0.44159177	0	-0.20554	2.822486502	2.822486502	-0.382172293
8	Midlands	1.879293	-2.41820136	0	-0.20554	-0.260803589	-0.260803589	-1.172816129
9	Eastern	-1.31895	1.82747895	0	-0.20554	-0.062498992	-0.062498992	0.525455995
10	South Wales	7.658428	-0.44159177	-4.49363148	-0.20554	3.504713418	2.605987123	-4.875803769
11	South East	-4.49926	3.286479451	0	-0.20554	-2.075613432	-2.075613432	1.109056195
12	London	-3.68584	-0.44159177	-1.42390706	-0.20554	-5.383774747	-5.66855616	-1.806079357
13	Southern	-1.27869	-2.68924168	0	-0.20554	-3.635618031	-3.635618031	-1.281232259
14	South Western	0.974095	-5.14321713	0	-0.20554	-3.346013988	-3.346013988	-2.262822436

A list of sites, along with the generation zones they are mapped to under both options, is in table S6 below, and is published as part of the March tariff excel tables.

Table S6 Indicative generation wider tariffs under option 2 (48 zones)

Zone	Zone Name	Tariffs (£/kW)				Example tariffs for a generator of each technology type		
		System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	Zone 1	3.562264	15.707581	45.706194	-0.016568	52.676716	61.817954	51.972658
2	Zone 2	1.666866	15.707581	14.981859	-0.016568	26.201851	29.198223	21.248324
3	Zone 3	3.647810	15.707581	36.763887	-0.016568	45.608417	52.961194	43.030352
4	Zone 4	-0.681317	19.694134	16.802836	-0.016568	28.499691	31.860258	24.663922
5	Zone 5	2.511181	16.445561	15.112523	-0.016568	27.741080	30.763585	21.674179
6	Zone 6	3.968410	19.314321	16.491983	-0.016568	32.596885	35.895282	24.201144
7	Zone 7	4.084331	19.694134	16.643999	-0.016568	33.138270	36.467070	24.505085
8	Zone 8	1.666866	17.905481	15.112523	-0.016568	28.064701	31.087206	22.258147
9	Zone 9	4.161072	20.270407	16.731945	-0.016568	33.746385	37.092774	24.823540
10	Zone 10	2.571733	14.471540	13.370668	-0.016568	24.828932	27.503065	19.142716
11	Zone 11	4.846430	14.471540	16.320069	-0.016568	29.463150	32.727164	22.092117
12	Zone 12	4.969074	16.786807	15.916695	-0.016568	31.115308	34.298647	22.614850
13	Zone 13	4.789462	15.273896	14.189360	-0.016568	28.343499	31.181371	20.282350
14	Zone 14	4.556804	14.886756	13.736887	-0.016568	27.439151	30.186528	19.675022
15	Zone 15	4.214900	19.663711	17.181704	-0.016568	33.674665	37.111006	25.030621
16	Zone 16	2.535133	9.949844	13.736887	-0.016568	21.467951	24.215328	17.700257
17	Zone 17	3.770178	12.634000	12.005011	-0.016568	23.464819	25.865821	17.042043
18	Zone 18	2.098013	12.030364	11.663775	-0.016568	21.036755	23.369510	16.459352
19	Zone 19	2.233786	12.560223	11.989546	-0.016568	21.857033	24.254942	16.997067
20	Zone 20	2.759209	8.495345	9.014648	-0.016568	16.750636	18.553566	12.396218
21	Zone 21	2.582738	8.901379	9.516437	-0.016568	17.300423	19.203711	13.060421
22	Zone 22	2.528946	10.388414	11.418425	-0.016568	19.957850	22.241535	15.557223
23	Zone 23	1.989746	7.132156	7.110870	-0.016568	13.367598	14.789772	9.947164
24	Zone 24	1.688262	6.006774	5.676647	-0.016568	11.018431	12.153761	8.062789
25	Zone 25	3.359657	11.704461	0.000000	-0.016568	12.706658	12.706658	4.665217
26	Zone 26	3.918572	4.466869	3.675570	-0.016568	10.415956	11.151070	5.445750
27	Zone 27	1.728953	6.867596	0.000000	-0.016568	7.206462	7.206462	2.730471
28	Zone 28	4.588162	1.778376	0.132201	-0.016568	6.100056	6.126497	0.826984
29	Zone 29	3.509931	-0.017503	0.000000	-0.016568	3.479361	3.479361	-0.023569
30	Zone 30	1.987654	0.480138	0.000000	-0.016568	2.355196	2.355196	0.175487
31	Zone 31	5.345478	-0.513243	0.000000	-0.016568	4.918316	4.918316	-0.221865
32	Zone 32	3.270948	-2.165891	0.000000	-0.016568	1.521668	1.521668	-0.882924
33	Zone 33	1.807946	-3.083163	0.000000	-0.016568	-0.675152	-0.675152	-1.249833
34	Zone 34	0.106514	1.645998	0.000000	-0.016568	1.406744	1.406744	0.641831
35	Zone 35	-2.283183	1.851460	0.000000	-0.016568	-0.818583	-0.818583	0.724016
36	Zone 36	9.703171	-4.860177	0.000000	-0.016568	5.798461	5.798461	-1.960639
37	Zone 37	-5.928025	-4.294744	0.000000	-0.016568	-9.380388	-9.380388	-1.734465
38	Zone 38	-1.882916	-0.215130	0.000000	-0.016568	-2.071588	-2.071588	-0.102620
39	Zone 39	-4.564615	4.212092	0.000000	-0.016568	-1.211509	-1.211509	1.668269
40	Zone 40	-4.614080	2.468493	0.000000	-0.016568	-2.655854	-2.655854	0.970829
41	Zone 41	-4.213155	3.892558	0.000000	-0.016568	-1.115677	-1.115677	1.540455
42	Zone 42	-2.865273	-2.247798	0.000000	-0.016568	-4.680079	-4.680079	-0.915687
43	Zone 43	0.084155	-3.911858	0.000000	-0.016568	-3.061899	-3.061899	-1.581311
44	Zone 44	-3.613366	-0.302511	0.000000	-0.016568	-3.871942	-3.871942	-0.137572
45	Zone 45	-1.627052	-3.224741	0.000000	-0.016568	-4.223412	-4.223412	-1.306464
46	Zone 46	-0.147702	-5.811403	0.000000	-0.016568	-4.813392	-4.813392	-2.341129
47	Zone 47	2.818669	-5.037728	0.000000	-0.016568	-1.228081	-1.228081	-2.031659
48	Zone 48	6.271503	-4.995642	0.000000	-0.016568	2.258421	2.258421	-2.014825

Tools and supporting information

Further 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 publishing a webinar for the March forecast of 2021/22 tariffs on Tuesday 7 April 2020. This will be published on our website and a communication will be sent out to highlight that this is now available. For any questions please see the contact us, 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 under 2021/22 forecasts:

https://www.nationalgrideso.com/tnuos

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

A

Appendix A: Background to TNUoS charging

Background to TNUoS charging

National Grid 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 is also used to ensure the correct proportion of revenue is collected from generation and demand. The locational and residual 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.

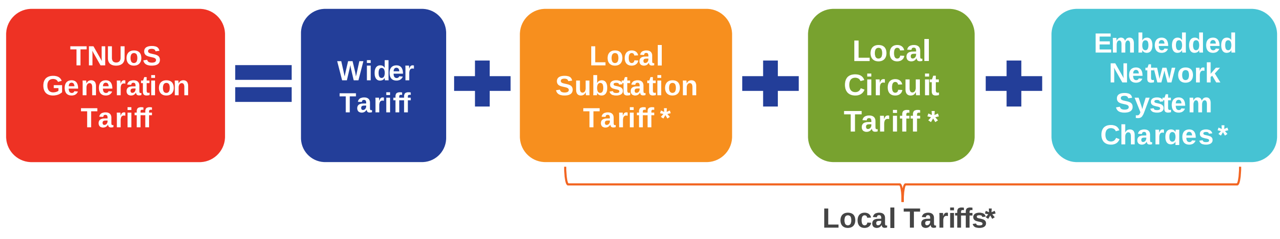
Generation charging principles

Generators pay TNUoS (Transmission Network Use of System) tariffs to allow NGESO to recover the capital costs of building and maintaining the transmission network on behalf of the transmission asset owners (TOs).

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*

of the whole

system, whereas the local tariffs are for the use of assets in the immediate vicinity of the connection site.

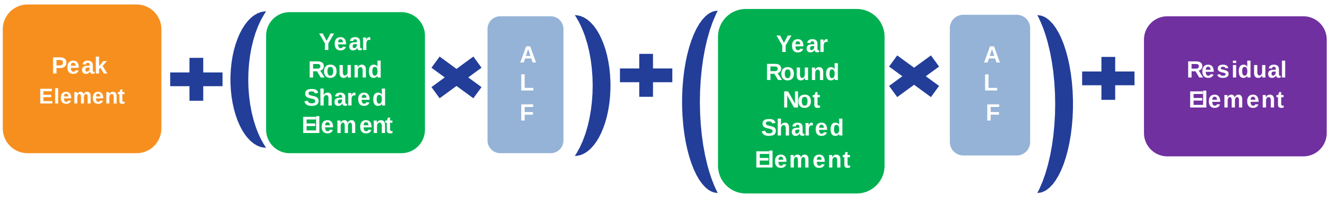
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

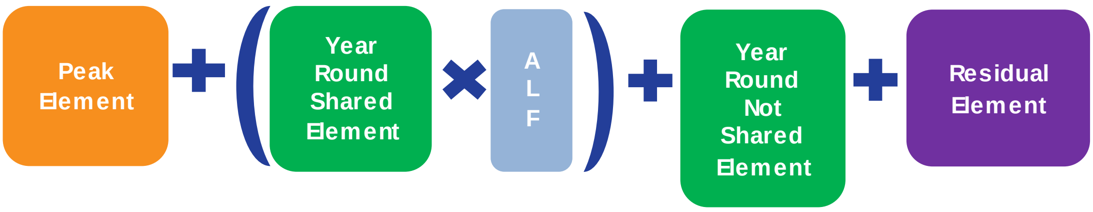
Conventional Carbon Generators

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



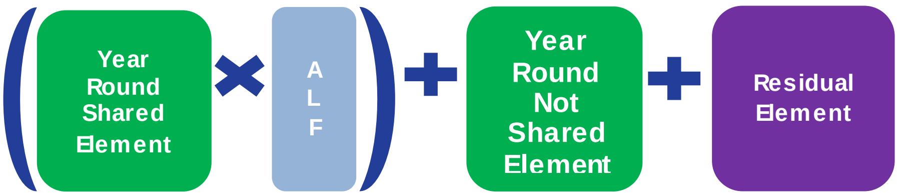
Conventional Low Carbon Generators

(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 **Residual** 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 ALFs used in these tariffs are listed from page 52.

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 RPI each year.

Local circuit tariffs

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

Embedded network system charges

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

Offshore generators connecting to embedded OFTO will need to pay an estimated DUoS charge to NGET through TNUoS tariffs to cover DNO charges.

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:

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

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.

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.

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

[11] Distribution network Use of System charges

Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers now 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 charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[12] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data 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[13].

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, a phased residual over 3 years (reaching £0/kW in 2020/21) 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[14].

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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[12] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data
[13] https://www.nationalgrideso.com/document/130641/download
[14] https://www.nationalgrideso.com/charging/charging-guidance

B

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology for 2021/22

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2021/22. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

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

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

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

The Small Generator Discount

The Small Generator Discount is defined in National Grid ESO's Electricity Transmission licence condition C13. This licence condition is due to expire on 31 March 2021 in line with the implementation of TCR.

Table 19 Summary of in flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP280	Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users	Remove demand residual charges from generation and storage	April 2021 if approved
CMP306	Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital	Potentially reduce the 2021/22 TNUoS revenue by less than £20m due to a one-off adjustment	April 2021 if approved
CMP310	CUSC section 14 changes in the event the UK leaves the EU without an agreement	Modify existing references to EU regulations to reflect the changes as foreseen in the relevant Statutory Instruments.	As soon as practicable following UK's exit from the EU, in the event no agreement is in place
CMP316	TNUoS Arrangements for Co-located Generation Sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types	April 2021, if approved
CMP317 & CMP327	Identification and exclusion of Assets Required for Connection when setting TNUoS charges	Removal of revenue linked to "generator only spurs" from the calculation of generation revenue cap under the EU rules, and setting generation residual tariff to 0	April 2021, if approved
CMP324 & CMP325	Generation Re-zoning	Revise TNUoS generation zoning methodology	April 2021, if approved

Name	Title	Effect of proposed change	Possible implementation
CMP332	Transmission Demand Residual bandings and allocation (TCR)	Replacing TNUoS demand residual tariff with fixed p/site/day charge for final demand users	Withdrawn, and seeking alternative implementation date

C

Appendix C: Breakdown of locational HH and EE tariffs

Breakdown of HH and EET locational tariffs

The table below shows the locational demand tariff elements used in the gross HH demand tariff and the EET, and the associated changes from the 2020/21 Final Tariffs to the 2021/22 March Tariffs.

Table 20 Demand HH locational tariffs

Demand Zone		2020/21 Final		2021/22 March		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	- 2.180689	- 28.424741	- 1.755398	- 30.047579	0.425291	- 1.622838
2	Southern Scotland	- 2.145803	- 20.826183	- 2.660625	- 21.332921	- 0.514823	- 0.506739
3	Northern	- 3.617626	- 8.092652	- 3.432121	- 8.179343	0.185506	- 0.086691
4	North West	- 1.689726	- 3.367878	- 1.351652	- 3.611617	0.338074	- 0.243739
5	Yorkshire	- 2.524634	- 1.372967	- 2.477629	- 1.633776	0.047004	- 0.260809
6	N Wales & Mersey	- 1.840168	- 0.987157	- 2.205760	- 0.478556	- 0.365592	0.508601
7	East Midlands	- 2.243484	1.899133	- 2.321682	1.889024	- 0.078198	- 0.010109
8	Midlands	- 1.926300	2.842465	- 1.768773	2.894364	0.157527	0.051899
9	Eastern	1.389367	0.366804	1.447674	0.313126	0.058307	- 0.053678
10	South Wales	- 6.024252	4.905766	- 6.473050	4.947334	- 0.448798	0.041568
11	South East	3.906590	0.862979	3.872936	0.791247	- 0.033654	- 0.071732
12	London	5.776148	1.758574	5.951036	1.678881	0.174888	- 0.079694
13	Southern	1.974463	4.065673	1.898214	4.104932	- 0.076249	0.039259
14	South Western	- 0.466066	5.754189	- 0.661798	5.832732	- 0.195732	0.078543

Table 21 shows the breakdown of the components that make up the EET.

Table 21 Breakdown of the EET

Demand Zone		2020/21 Final		2021/22 March		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	- 30.60543	3.41493	- 31.80298	3.51357	- 1.19755	0.09864
2	Southern Scotland	- 22.97199	3.41493	- 23.99355	3.51357	- 1.02156	0.09864
3	Northern	- 11.71028	3.41493	- 11.61146	3.51357	0.09881	0.09864
4	North West	- 5.05760	3.41493	- 4.96327	3.51357	0.09433	0.09864
5	Yorkshire	- 3.89760	3.41493	- 4.11141	3.51357	- 0.21380	0.09864
6	N Wales & Mersey	- 2.82733	3.41493	- 2.68432	3.51357	0.14301	0.09864
7	East Midlands	- 0.34435	3.41493	- 0.43266	3.51357	- 0.08831	0.09864
8	Midlands	0.91617	3.41493	1.12559	3.51357	0.20943	0.09864
9	Eastern	1.75617	3.41493	1.76080	3.51357	0.00463	0.09864
10	South Wales	- 1.11849	3.41493	- 1.52572	3.51357	- 0.40723	0.09864
11	South East	4.76957	3.41493	4.66418	3.51357	- 0.10539	0.09864
12	London	7.53472	3.41493	7.62992	3.51357	0.09519	0.09864
13	Southern	6.04014	3.41493	6.00315	3.51357	- 0.03699	0.09864
14	South Western	5.28812	3.41493	5.17093	3.51357	- 0.11719	0.09864

The locational element is the sum of the peak and year round elements for the HH tariff in that zone (see the table above).

The AGIC is the Avoided GSP Infrastructure Credit, which is indexed by average May to October RPI each year. The AGIC will be reviewed at the next priced control ahead of the 2021/22 charging year.

D

Appendix D: Locational demand profiles

Locational demand profiles

The table below shows the latest locational demand and demand charging base forecast used for the 2021/22 March forecast.

The gross half-hourly (HH) demand forecast has decreased to 19.4GW and the non-half-hourly (NHH) demand forecast has decreased to 24.0TWh. Embedded export volumes have also decrease and are forecast to be 6.8GW.

HH demand is calculated on a gross basis rather than net, and the negative demand caused by embedded generation is listed separately.

Table 22 Demand profile

		2020/21 Final					2021/22 March				
Zone	Zone Name	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	266	1,470	450	0.78	1,330	198	1,457	445	0.74	1,233
2	Southern Scotland	2,399	3,360	1,254	1.72	870	2,399	3,343	1,229	1.64	634
3	Northern	2,031	2,510	1,062	1.22	470	2,031	2,509	1,056	1.17	484
4	North West	2,869	3,950	1,489	2.00	380	2,869	3,927	1,501	1.91	368
5	Yorkshire	3,984	3,770	1,614	1.83	710	3,984	3,736	1,594	1.74	684
6	N Wales & Mersey	2,788	2,570	1,056	1.27	580	2,788	2,568	1,053	1.21	562
7	East Midlands	5,279	4,590	1,814	2.27	550	5,279	4,553	1,800	2.16	534
8	Midlands	4,433	4,170	1,617	2.06	240	4,433	4,140	1,598	1.97	228
9	Eastern	5,601	6,340	2,131	3.22	610	5,601	6,268	2,093	3.07	640
10	South Wales	1,604	1,780	819	0.87	380	1,604	1,775	815	0.83	368
11	South East	3,194	3,830	1,186	1.99	330	3,194	3,795	1,169	1.90	322
12	London	5,056	4,120	2,277	1.88	120	5,056	4,080	2,261	1.80	124
13	Southern	7,178	5,390	2,084	2.68	390	7,178	5,340	2,055	2.55	386
14	South Western	2,151	2,550	753	1.35	270	2,151	2,537	762	1.28	252
Total		**48,833**	**50,400**	**19,607**	**25.13**	**7,230**	**48,765**	**50,028**	**19,431**	**23.97**	**6,820**

E

Appendix E: Annual Load Factors

Specific ALFs

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

For the purposes of this forecast, we have used the final version of the 2020/21 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2014/15 to 2018/19. Generators which commissioned after 1 April 2016 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 2021/22 also use the Generic ALF for their first year of operation.

The specific and generic ALFs that will apply to 2021/22 TNUoS Tariffs will be updated by November 2020. The specific and generic ALFs for 2020/21 tariffs, as used in this forecast, are published here.

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

Generic ALFs

Table 23 Generic ALFs

Technology	Generic ALF
Gas_Oil #	0.3935%
Pumped_Storage	10.2893%
Tidal *	18.9000%
Biomass	39.8387%
Wave *	31.0000%
Onshore_Wind	35.6660%
CCGT_CHP	50.9470%
Hydro	41.7886%
Offshore_Wind	48.3204%
Coal	27.7372%
Nuclear	77.5645%

Includes OCGTs (Open Cycle Gas Turbine generating plant).

*Note: ALF figures for Wave and Tidal 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.

F

Appendix F: Contracted generation changes since the 2020/21 Final Tariffs

The table below shows the TEC changes notified between the 2020/21 Final Tariffs Report and the 2021/22 March forecast. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

The tariffs in this forecast are based on National Grid ESO's best view and therefore may include different generation to that shown below.

Table 24 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Arenko Lister Drive	49.9	LISD20	15
Arenko Osbaldwick	49.9	OSBA40	15
Auchencrosh (interconnector CCT)	160	AUCH20	10
Bramford Tertiary PP	49.9	GRMO20	9
Burwell (Tertiary)	49.9	BURW40	18
Bustleholme	49.9	BUST20	18
Coventry	49.9	COVE20	18
Crookedstane Windfarm	25.4	CLYS2R	11
Cumberhead	-50	GAWH10	11
Damhead Creek 2	1800	KINO40	24
Douglas West	45	COAL10	11
Exeter (Tertiary)	49.9	EXET40	26
Fallago Rig 2	41.4	FALL40	11
Firth of Forth Phase 1	1075	TEAL20	9
Gilston Hill Wind Farm	25.2	DUNE10	11
Glen Kyllachy Wind Farm	48.5	GLKO10	1
Harker	-49.9	HARK40	12
Holyhead	300	WYLF40	19
Hornsea Power Station 2B	440	KILL40	15
Hornsea Power Station 2C	440	KILL40	15
J G Pears	-17	HIGM20	16
Kennoxhead Wind Farm Extension	60	MIDM10	11
Kings Lynn A	99	WALP40_EME	17
Kirkby (Tertiary)	49.9	KIBY20	15
Llanwern Phase 1	-49.9	WHSO20	21
MeyGen Tidal	15	GILB10	1
Millennium South	25	MILS1Q	3
Moray Firth Offshore Wind Farm	740	NEDE20	2
North Killingholme Power Project	540	KILL40	15
Nursling	-49.9	NURS40	26
Oldbury (Tertiary)	49.9	OLDB4A	18
Progress Power Station	299	BRFO40	18
Sandy Knowe Wind Farm	51	GLGL1Q	10
Seabank (Tertiary)	49.9	SEAB40	22
Sellindge (Tertiary)	49.9	SELL40	24
South Kyle	165	NECU10	10
Spalding Energy Expansion	550.01	SPLN40	17
Tralorg Wind Farm	-20	MAHI20	10
Triton Knoll Offshore Wind Farm	540	BICF4A	17
Upware Solar Farm	49.99	BURW40	18
Willington	1145	WILE40	18
Worset Solar Park	38	HARM20	13

The contracted generation used in the Transport model will be fixed at the November forecast of 2021/22 tariffs, using the TEC register as of 31 October 2020, as stated by the CUSC 14.15.6.

G

Appendix G 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 revenue forecast for year 2021/22, and the revenue forecasts will be updated later this year. In addition, there are some pass-through items that are to be collected by NGESO via TNUoS charges, including the Network Innovation Competition (NIC) fund, contribution made from IFA, and site-specific adjustments by TOs etc.

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 one 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 Network Innovation Competition (NIC) Funding, and pass 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.

Table 25 NGESO revenue breakdown

	NGESO TNUoS Other Pass-Through			
Term	**March Forecast**	**August Forecast**	**Nov Draft**	**Jan Final**
Embedded Offshore Pass-Through (OFETt)	0.6			
Network Innovation Competition (NICFt)	13.9			
Interconnectors Cap&Floor Revenue Adjustment (TICFt)	5.1			
ESO Network Innovation Allowance (NIAt)	3.0			
Offshore Transmission Revenue (OFTOt)	524.8			
Financial facility (FINt)				
Site Specific Charges Discrepancy (DISt)				
Termination Sums (TSt)				
NGET revenue pas-through (NGETTOt)*	1,754.9			
SPT revenue pass-through (TSPt)	376.7			
SHETL revenue pass-through (TSHt)	374.0			
Total	**3,053.1**			

A few items (including FINt, DISt and TSt) are set to zero in the March forecast cycle. FINt was introduced as a "bridging" financial facility, following the legal separation of ESO from NGET, and will be reviewed for RIIO-2. DISt and TSt are based on TOs' ad-hoc activities during year 2020/21, and at this stage, no information is available.

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 updated us with their revenue forecast for year 2021/22, based on RIIO-1 assumptions, and therefore the revenue forecasts are yet to be updated later this year.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2021/22 is forecast to be £524.8m, an increase of £81m compared to 2020/21. Revenues have been adjusted using updated revenue forecasts provided by the OFTOs in addition to our RPI forecast (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. The latest interconnector revenue forecast shows it increases 2021/22 TNUoS revenue by around £5.1m.

Table 26 NGET revenue breakdown

2020/21 Revenue Description		Licence Term	National Grid Electricity Transmission			
Regulatory Year			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 1,585.1			
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (393.9)			
RPI True Up	A3	TRUt	£ (1.1)			
RPI Forecast	A4	RPIFt	£ 1.4			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 1,690.0**			
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ 38.1			
Temporary Physical Disconnection	B2	TPDt	£ 4.8			
Inter TSO Compensation	B4	ITCt	£ (2.8)			
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ 40.2**			
Financial Incentive for Timely Connections Output	C5	-CONADJt				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ 17.2			
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ 17.2**			
Network Innovation Allowance	D	NIAt	£ 7.6			
Future Environmental Discretionary Rewards	F	EDRt	£ -			
Transmission Investment for Renewable Generation	G	TIRGt	£ -			
Correction Factor	-K	-K	£ -			
Financial Facility	FINt	FINt	£ -			
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 1,754.9**			
Pre-vesting connection charges	S1		£ -			
Rental Site	S2		£ -			
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 1,754.9**			

Table 27 SPT revenue breakdown

2020/21 Revenue Description		Scottish Power Transmission			
Regulatory Year		March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	£ 261.9			
Price Control Financial Model Iteration Adjustment	A2	£ (8.5)			
RPI True Up	A3	£ (2.1)			
RPI Forecast	A4	£ 1.4			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**£ 356.9**			
Pass-Through Business Rates & Licence fee	B1+B3	£ 4.1			
Temporary Physical Disconnection	B2	£ -			
Inter TSO Compensation	B4				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**£ 4.1**			
Financial Incentive for Timely Connections Output	C5				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	£ 3.4			
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**£ 3.4**			
Network Innovation Allowance	D	£ -			
Future Environmental Discretionary Rewards	F	£ -			
Transmission Investment for Renewable Generation	G	£ 32.5			
Correction Factor	-K	£ (7.4)			
Financial Facility	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**£ 389.5**			
Pre-vesting connection charges	S1	£ 12.7			
Rental Site	S2				
TNUoS Collected Revenue [T=M-B5-P]	**T**	**£ 376.7**			

Table 28 SHETL revenue breakdown

2020/21 Revenue Description		SHE Transmission			
Regulatory Year		March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	£ 273.4			
Price Control Financial Model Iteration Adjustment	A2	£ (8.2)			
RPI True Up	A3	£ -			
RPI Forecast	A4	£ 1.4			
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**£ 376.6**			
Pass-Through Business Rates & Licence fee	B1+B3	£ -			
Temporary Physical Disconnection	B2	£ -			
Inter TSO Compensation	B4				
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**£ -**			
Financial Incentive for Timely Connections Output	C5				
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	£ -			
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**£ -**			
Network Innovation Allowance	D	£ 0.9			
Future Environmental Discretionary Rewards	F	£ -			
Transmission Investment for Renewable Generation	G	£ -			
Correction Factor	-K	£ -			
Financial Facility	FINt				
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**£ 377.5**			
Pre-vesting connection charges	S1	£ 3.4			
Rental Site	S2				
TNUoS Collected Revenue [T=M-B5-P]	**T**	**£ 374.0**			

Table 29 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	25/03/2020								
Regulatory Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.8	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.5	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.5	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.5	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.3	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.5	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.2	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.3	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.9	Current revenues plus indexation
Thanet	78.9	17.5	15.7	19.5	18.6	19.2	19.7	20.9	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	29.2	29.7	30.4	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	30.9	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	22.6	23.6	23.1	24.5	Current revenues plus indexation
Humber Gateway			29.3	9.7	12.1	12.5	11.3	13.1	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.3	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.2	Current revenues plus indexation
Dudgeon						18.7	19.2	20.1	Current revenues plus indexation
Race Bank						66.0	26.7	28.0	Current revenues plus indexation
Galloper							37.8	17.2	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2020/21								117.3	National Grid Forecast
							63.9		
Forecast to asset transfer to OFTO in 2021/22								23.4	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**260.8**	**265.5**	**317.9**	**390.6**	**443.8**	**524.8**	

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

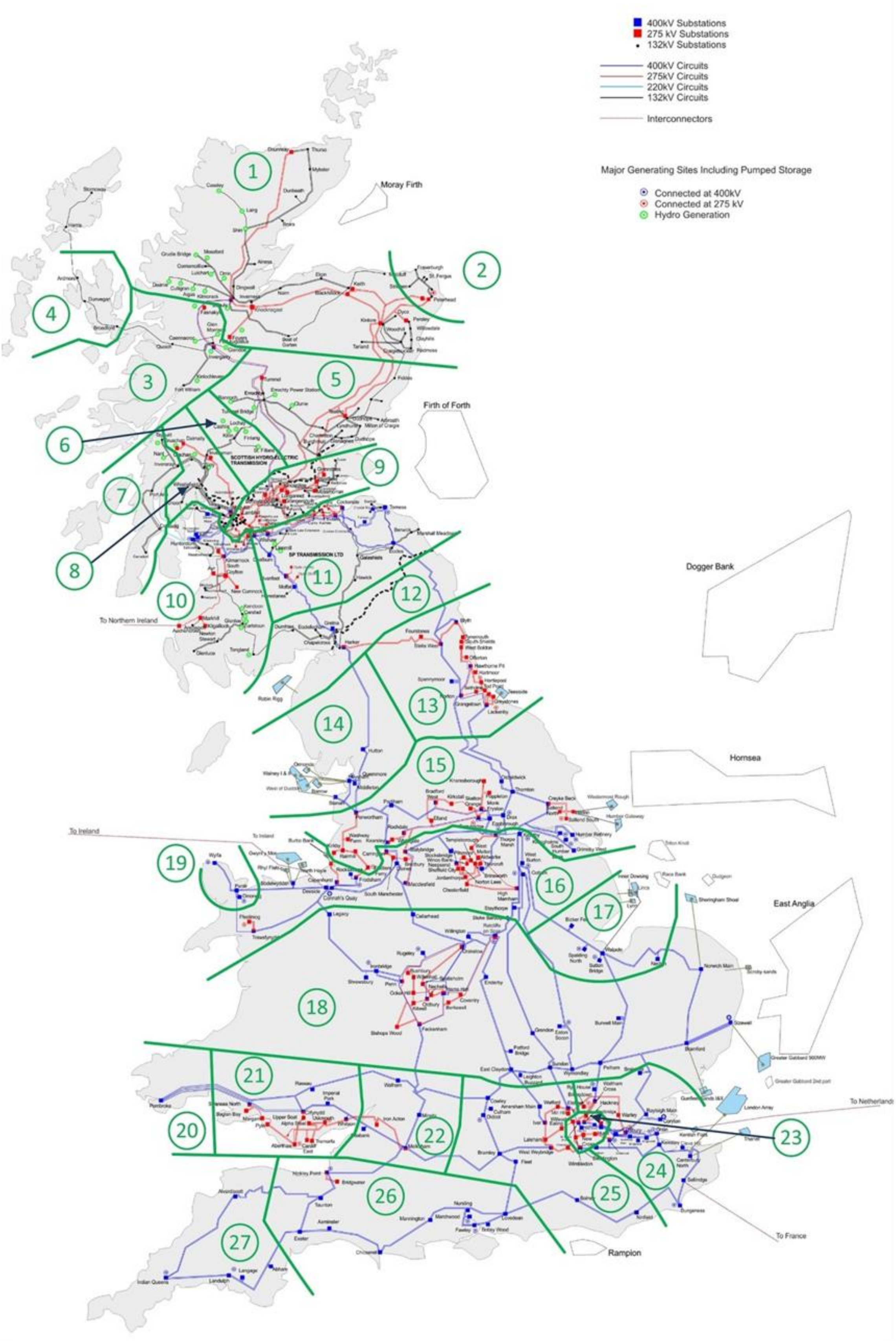
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

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

H

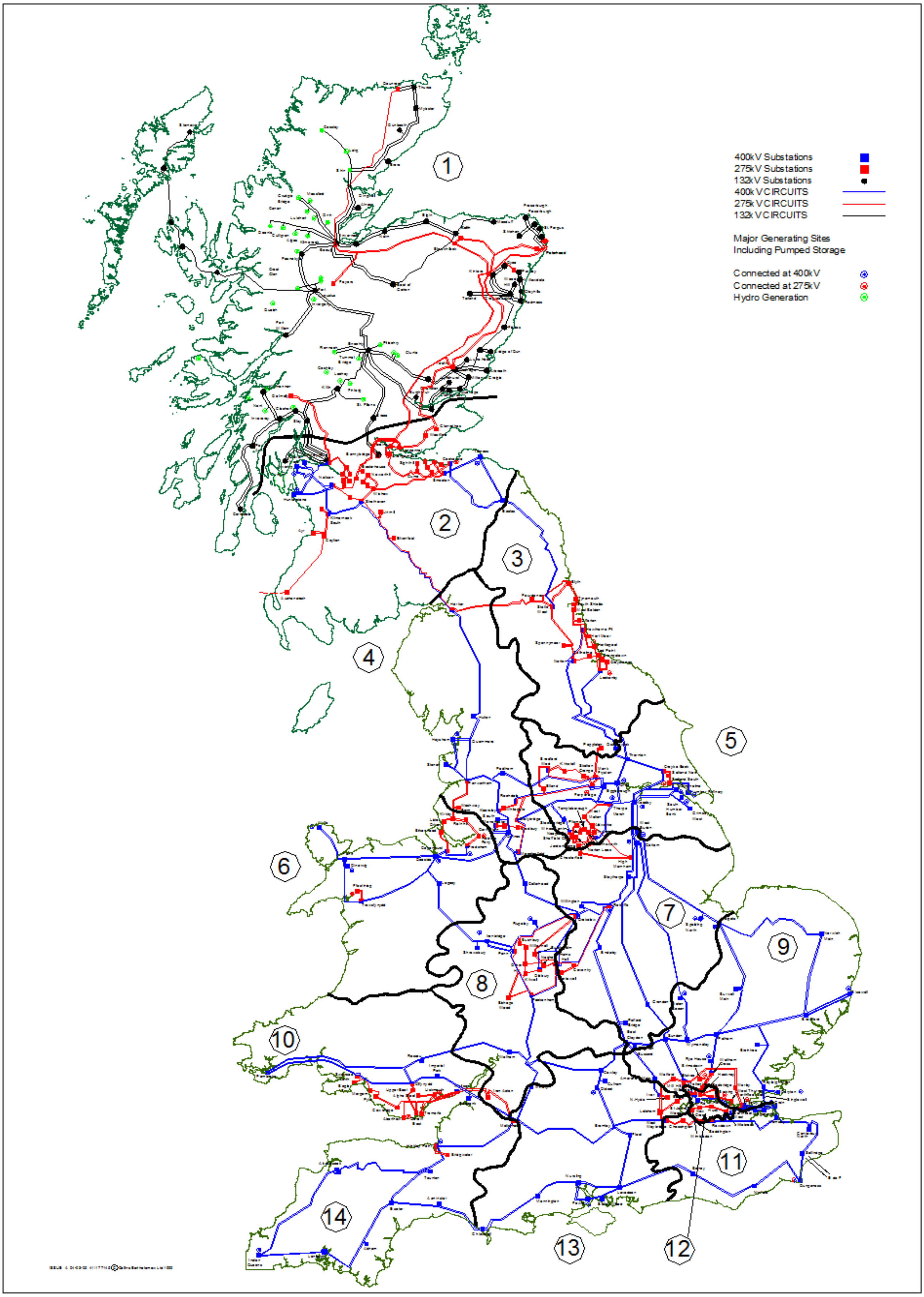
Appendix H: Generation zones map

Figure A2: GB Existing Transmission System



I

Appendix I: Demand zones map


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
1
2
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Appendix J: Quarterly Changes to TNUoS parameters

Parameters affecting TNUoS tariffs

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

<table>
<tr><th colspan="6">2021/22TNUoS Tariff Forecast</th></tr>
<tr><th colspan="2"></th><th>March 2020</th><th>August 2020</th><th>Draft Tariffs November 2020</th><th>Final Tariffs January 2021</th></tr>
<tr><td colspan="2">Methodology</td><td colspan="4">Open to industry governance</td></tr>
<tr><td rowspan="4">LOCATIONAL</td><td>DNO/DCC Demand Data</td><td colspan="2">Initial update using previous year’s data source</td><td>Week 24 updated</td><td></td></tr>
<tr><td>Contracted TEC</td><td>Latest TEC Register</td><td>Latest TEC Register</td><td>TEC Register Frozen at 31 October</td><td></td></tr>
<tr><td>Network Model</td><td colspan="2">Initial update using previous year’s data source (except local circuit changes which are updated quarterly)</td><td>Latest version based on ETYS</td><td></td></tr>
<tr><td>RPI</td><td colspan="3">forecast</td><td>actual</td></tr>
<tr><td rowspan="6">RESIDUAL</td><td>OFTO Revenue (part of allowed revenue)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>NG best view</td></tr>
<tr><td>Allowed Revenue (non OFTO changes)</td><td>Initial update using previous year’s data source</td><td>Update financial parameters</td><td>Latest TO forecasts</td><td>From TOs</td></tr>
<tr><td>Demand Charging Bases</td><td>Initial update using previous year’s data source</td><td>Revised forecast</td><td>Revised forecast</td><td>Revised by exception</td></tr>
<tr><td>Generation Charging Base</td><td>NG best view</td><td>NG best view</td><td>NG best view</td><td>NG final best view</td></tr>
<tr><td>Generation ALFs</td><td colspan="2">Previous year’s data source</td><td>New ALFs published</td><td></td></tr>
<tr><td>Generation Revenue (G/D split)</td><td>Forecast</td><td>Forecast</td><td>Forecast</td><td>Generation revenue £m fixed</td></tr>
</table>

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