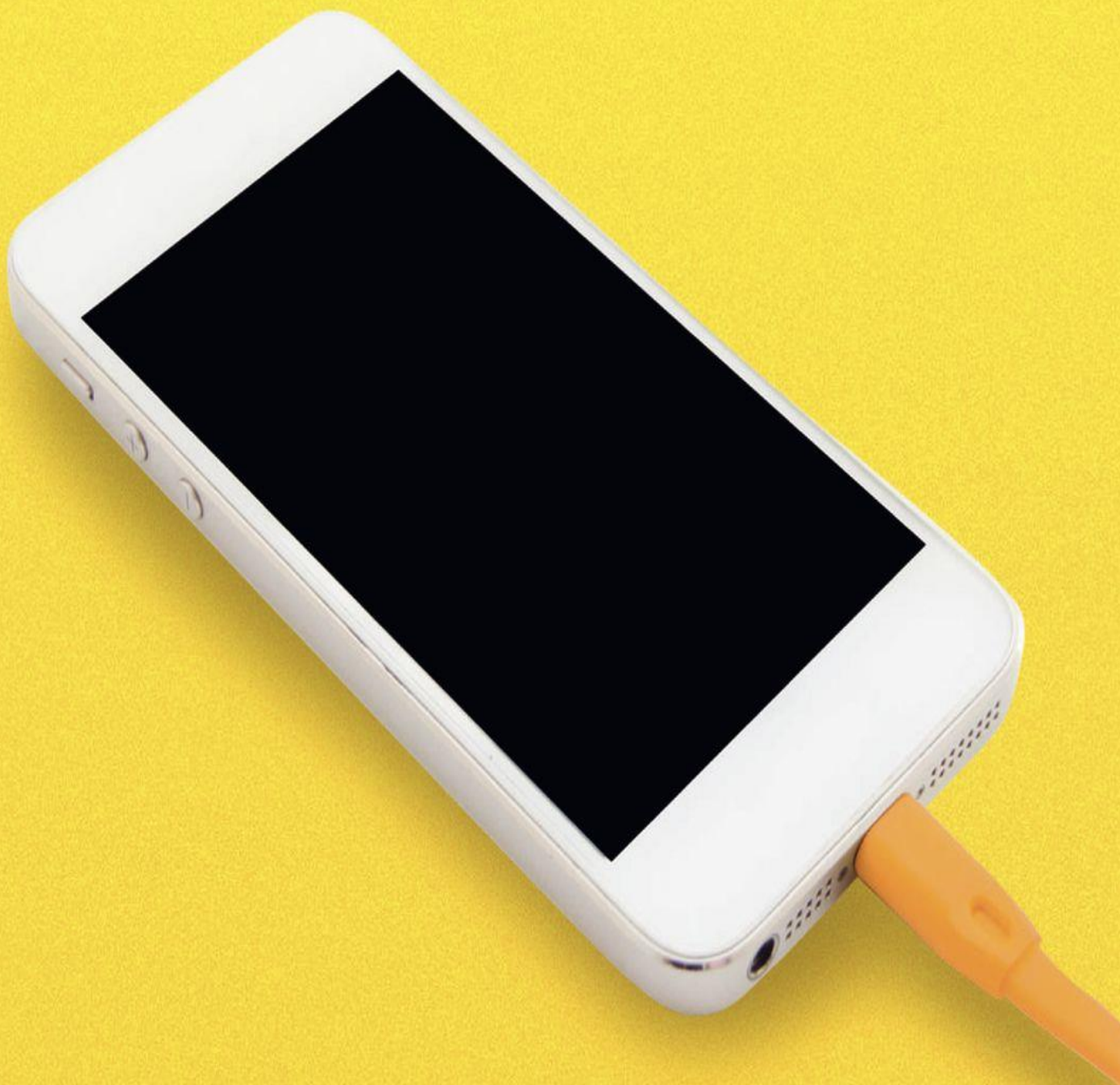


Five-Year View of TNUoS Tariffs for 2021/22 to 2025/26

National Grid Electricity System Operator

August 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 Great Britain. It is applicable to transmission network users including generators and suppliers. This document contains the five-year view on future TNUoS Tariffs for 2021/22 - 2025/26.

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish a five-year view on future TNUoS tariffs regularly on our website¹. This report provides the forecast for the period of 2021/22 - 2025/26 and also includes the second quarterly forecast of TNUoS tariffs for year 2021/22.

We fully appreciate that there are uncertainties with several ongoing charging methodology changes and price control process for the onshore Transmission Owners (TOs). We therefore have also included a number of sensitivity scenario analysis to help the industry to understand the potential implications.

Major Regulatory Changes - TCR

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). The TGR changes are planned to be implemented from April 2021 and will affect generation residual tariffs, while the TDR changes are expected to be implemented from April 2022. In this forecast, we have included TGR and TDR according to the planned implementation dates. In addition, we have provided a sensitivity analysis for phased implementation of TGR.

Price Control Impact

This report covers charging years 2021/22 – 2025/26, which is the new price control period (RIIO-2) for onshore TOs. There are various parameters that are required to be revised at the start of each price control, based on the final outcome of TOs' business plans. We are in the process of reviewing these RIIO-2 related elements, which are to

be finalised with Ofgem's Final Determinations on the TOs business plans.

In this report, we have recalculated the locational security factor, and applied RPI to some of the RIIO-1 parameters as indicative RIIO-2 parameters (listed in the Forecast Approach section).

We have also kept the same number of generation zones (27 in total) as in RIIO-1, to provide a like-for-like comparison with last year's tariffs. Generation zoning criteria are currently being reviewed by CUSC modification CMP324/325 workgroup, and the modifications have not been concluded. We have also included two sensitivities on alternative generation zone numbers (14 zones and 48 zones respectively) for the charging year 2021/22 and 2025/26, to provide an early view of the generation wider tariffs under alternative zoning criteria.

Total revenues to be recovered

The total TNUoS revenue to be collected is forecast at £3,048.6m for 2021/22 (a reduction of £4.5m from our March forecast), rising to £3,758m in 2025/26. The forecast was based on TOs' data with RIIO-1 parameter assumptions. The 2021/22 revenue forecast will be updated through the year and finalised by January Final Tariffs. We have provided a sensitivity analysis on onshore TOs' revenue with a different inflation indexation proposed in Ofgem's Draft Determination (DD).

Generation tariffs

The total revenue to be recovered from generators has increased significantly from 2020/21 due to the implementation of TGR. The generation revenue is £826.4m for year 2021/22 (an increase of ~£452m from the current charging year). It would grow to

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

£1199.8m by 2025/26, mainly driven by the increase in offshore local charges.

The generation charging base for 2021/22 has been updated to 76.9GW based on our best view, a small increase of 0.1GW from the March forecast. This view will be further refined throughout the year. The average generation tariff for 2021/22 is forecast at £10.74/kW, a slight increase by £0.05/kW from March forecast. The average generation tariff is expected to increase to £11.96/kW by 2025/26, mainly due to the increase in the generation charging base and increase in local charges.

Small Generator Discount

As defined in the NGENSO's licence, the Small Generator Discount (SGD) reduces the tariff for transmission connected generation connected at 132kV and with Transmission Export Capacity (TEC) <100MW.

The SGD is expected to expire by March 2021. As such, we have not included the SGD in the forecast tariffs.

Demand tariffs

Due to the implementation of TGR, the proportion of demand revenue would reduce. For 2021/22, demand revenue is forecast to be £2,222m, a reduction of £246m from 2020/21. The impact on the end consumer is forecast to be £31.87 in 2021/22, a small reduction of £0.15 compared to the March forecast. In line with increased TNUoS revenue, demand revenue would increase to £2,558m by 2025/26, with the consumer bill impact of £33.38.

In 2021/22, £13.6m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a reduction of £3.6m compared to March forecast, driven mainly by Avoided GSP Infrastructure Credit (AGIC) reduction. The average EET is thus lower by £0.66/kW at £1.86/kW. The EET credit is forecast to be £14.3m by 2025/26.

Not including the effect of the Small Generator Discount, the average gross HH demand tariff for 2021/22 is forecast to be

£44.81/kW, a decrease of £0.45/kW from March forecast, mainly due to locational tariff changes and the reduced EET credit. The average NHH demand tariff is 5.69p/kWh, a decrease of 0.03p/kWh.

From 2022/23, due to TDR implementation via CMP343, demand tariffs are expected to decrease significantly. The non-locational demand tariff (the demand residual) will be replaced with a £/site per year charge, applicable to final demand sites.

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:

- different numbers of generation zones are applied
- phased implementation of the Transmission Generation Residual (TGR) over three years
- Include congestion management costs in the TNUoS generation cap calculation
- Apply CPIH to the onshore TOs' revenue instead of RPI
- Include remote islands in North Scotland as part of the wider network

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

Next forecast

The timetable of TNUoS tariffs forecasts throughout year 2020/21 is available on our website².

Our next TNUoS tariff publication will be the draft forecast of 2021/22 tariffs in November 2020.

We endeavour to publish the next five-year TNUoS Forecast by March 2021.

²<https://www.nationalgrideso.com/document/162406/download>

Feedback

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

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

We strongly encourage all parties affected by the changes to the charging regime to engage with the Charging Futures Forum, or

with the specific CUSC modification workgroups to flag any concerns and suggestions.

Please contact 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



1

Forecast Approach

This report

This report contains the five-year view on TNUoS tariffs for the charging years 2021/22 – 2025/26, and the second quarterly 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 we 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 charging parameters, the latest available information and modification workgroup progress. Additionally, whenever we can, we have provided a series of sensitivity scenarios to help customers to understand the potential implications of the ongoing charging methodology changes.

COVID19 Impact

Due to the COVID19 pandemic, we have observed unprecedented levels of low demand since the lock down. We recognised that there is a risk of under recovery of TNUoS revenue for 2020/21. However, we are still in the process of understanding the overall impact to TNUoS revenue and would provide updates and insight to this impact in the following forecasts (November 2020 & January 2021). As such, we have not taken into account COVID19 impact in the demand charging base forecast for the next 5 years. The potential under recovery of revenue for 2020/21 has not been calculated into the 2022/23 forecast either (the year in which the recovery of revenue will be concluded).

Changes to the methodology as a result of Ofgem's Targeted Charging Review (TCR)

On 21 November 2019, Ofgem published their final decision³ 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 for the Transmission Generation Residual (TGR) changes and April 2022 for the Transmission Demand Residual (TDR) changes.

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

- TGR - 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 is 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
- TDR - The creation of specific NHH and HH demand residual charges, levied only to final demand (which is consumption used for purposes other than to operate a generating station, or to store and export), and on a 'site' basis. CMP343 (Transmission Demand Residual bandings and allocation) was raised to modify the CUSC methodology accordingly.

Our tariff forecast is largely based on the approved methodology in the CUSC. Although the above CUSC modifications are still on going, we have also incorporated the potential impacts by TGR which is due to take effect from April 2021, and by TDR which is due to take effect from April 2022, to illustrate the likely magnitudes of tariffs changes to customers.

The CMP317/327 workgroup has not been concluded yet, so for the purpose of this document we have assumed a negative adjustment factor is still required to ensure compliance with the EU cap, this is referred to as the generation residual in this report. It has also been assumed that all local onshore and local offshore tariffs are not included in the EU cap calculation.

³ <https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review>

Changes to the methodology due to Ofgem's Access and Forward-Looking Charges Significant Code Review (Access SCR)

In December 2018, Ofgem launched their Access SCR⁴. 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, and aims to consult on a minded-to decision and draft impact assessment in late 2020 and to publish a decision in early 2021. There are significant reforms being considered by Ofgem, and the target implementation date for these changes is currently set in 2023.

In this five-year view, we have not included Access SCR in the sensitivity analysis. We would incorporate it in the future forecast publications when the draft conclusions are available and we would be able to quantify the potential changes to tariffs.

Other charging methodology changes

There have been a few changes that have been approved to the charging methodology since March when we published the initial 2021/22 tariffs. These include

- CMP306 (Align annual connection charge rate of return to price control cost of capital)
- CMP320 (Island MITS radial link security factor)
- CMP337/338 (Impact of DNO contributions on actual project costs and expansion factors)

In this report, we have incorporated CMP320, CMP337/338 in the tariff calculation. We expect that information required to incorporate CMP306 would be provided by the TOs by January, and thus will be included in final tariff calculation for 2021/22. There are also a number of 'in-flight' proposals to change the charging methodologies. These are summarised in the CUSC modifications Table 32.

Changes to the TNUoS tariff calculation parameters due to new price control (RIIO-2)

In accordance with the CUSC, at the start of each price control, various aspects of the TNUoS parameters must be revised and updated. 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 received some of the data from the TOs to feed into the calculations. Table 1 lists the parameters to be updated for RIIO2 and the assumptions applied for this five-year view.

Table 1 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 SO-TO Code (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. Please note that CMP324/325 has been raised to review the generation zoning criteria which would determine the number of zones.	Our assumption in these tariffs is that the number of generation zones remains at 27. In the Sensitivity Analysis section, we have also included alternative generation tariffs under alternative zoning criteria (14 zones and 48 zones) ⁵ .

⁴ <https://www.ofgem.gov.uk/publications-and-updates/electricity-network-access-and-forward-looking-charging-review-significant-code-review-launch-and-wider-decision>

⁵ <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.	The collation of data from the TO's is ongoing and the further information towards the calculation of the expansion constant is required. Our assumptions for this forecast are based on the RIIO-1 parameter value uplifted by RPI.
Locational Onshore Security Factor	This is also called the "global" security factor. The value is currently 1.8. This will be recalculated by the start of RIIO-2 period.	In this forecast, we have recalculated the global security factor, and the preliminary finding is that the value remains as 1.8.
Local Substation Tariffs	Local Substation are to be recalculated in preparation for the start of the price control based on TO asset costs.	Local substation tariffs are still under review as part of the parameter refresh for the upcoming price control. Data is still being collated and the expectation is that the new tariffs will be available in our next forecast. Therefore, for the 5 year view will be based on the previous tariffs set for RIIO-1, uplifted by inflation.
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 based on that the existing discount with 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.	The AGIC has been updated for this five-year view as part of the RIIO-2 parameter refresh. The updated value is based on updated scheme data provided to us by the TO's as well as inflated historical schemes. This value will be the new base for the upcoming price control period and will be inflated by RPI as per the CUSC.

A nighttime photograph of a city skyline, likely London, featuring the Gherkin building (30 St Mary Axe) prominently in the center. The building is illuminated with warm yellow lights, and its distinctive conical shape is clearly visible. Other skyscrapers are visible in the background, also lit up. In the foreground, a large, dark, multi-story building with a grid-like facade is visible, and a street with some traffic and pedestrians is seen at the bottom right. A large white semi-circular graphic element is overlaid on the bottom left of the image, containing the number '2' and the title 'Generation tariffs'.

2

Generation tariffs

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

1. Generation tariffs summary

This section summarises our view of generation tariffs from 2021/22 to 2024/25 and how these tariffs were calculated.

For this forecast we have modelled the tariffs based on Ofgem's final decision for the Transmission Generation Residual (TGR) which would greatly increase the amount generators pay for TNUoS.

As part of our modelling of the TGR, we have assumed that local onshore and local offshore tariffs are not included in the European €2.50/MWh cap for generator transmission charges as proposed under CMP317/327, which has resulted in the increase of the generation residual.

We have included some sensitivities to model what the tariffs might be if the TGR was phased in over three years.

Table 2 Summary of average generation tariffs

Generation Tariffs (£/kW)	March	August	Five-year View			
	2021/22	2021/22	2022/23	2023/24	2024/25	2025/26
Residual	- 0.365971	- 0.232751	- 0.899494	- 1.598413	- 3.052436	- 3.263235
Average Generation Tariff*	10.690216	10.740461	11.162782	11.077140	10.986968	11.962772

*N.B These generation 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 are expected to increase from £5.30/kW in the current financial year to £10.74 in 2021/22, a slight increase of £0.05/kW since the March forecast. These average tariffs include revenues from local tariffs. This increase is driven by the implementation of CMP317/327 in 2021/22.

The generation residual is used 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. For the purpose of this report we have assumed that local onshore and offshore tariffs are not included in the European €2.50/MWh cap, as proposed under CMP317/327. However, a final decision has not been made for this code modification.

Over the next five years, it is expected that the average generation tariff will increase from £10.74/kW in 2021/22 to £11.96/kW by 2025/26. There is a slight decrease in the average tariff from 2022/23 and 2023/24, and again from 2023/24 to 2024/25. This is due to an increase in the wider tariffs driven by a larger charging base. This causes the residual to become more negative to ensure average revenues from generation is within the EU cap, decreasing the average tariff. By 2025/26 the local and offshore tariffs increase, counteracting the decrease in the residual which overall increases the average tariff from £10.99/kW in 2024/25 to £11.96/kW in 2025/26.

2. Generation wider tariffs

The following section summarises the five-year view of wider generation tariffs from 2021/22 to 2022/23. A brief description of generation wider tariff structure can be found in Appendix A.

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

The classifications of generator type are listed below:

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

The 80% and 40% ALFs, used in the tables in this section of the report, 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.

Please note that the Small Generator Discount is discontinued from 1st April 2021 and has not been included in the tariffs.

Table 3 Generation wider tariffs in 2021/22

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon	Conventional Low Carbon	Intermittent
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	80% Load Factor (£/kW)	80% Load Factor (£/kW)	40% Load Factor (£/kW)
1	North Scotland	4.342065	20.090101	18.866291	- 0.232751	35.274428	39.047686	26.669580
2	East Aberdeenshire	3.251840	10.650928	18.866291	- 0.232751	26.632864	30.406122	22.893911
3	Western Highlands	3.979920	18.288499	18.205231	- 0.232751	32.942153	36.583199	25.287880
4	Skye and Lochalsh	- 2.495443	18.288499	18.108400	- 0.232751	26.389325	30.011005	25.191049
5	Eastern Grampian and Tayside	4.450991	13.378695	15.525705	- 0.232751	27.341760	30.446901	20.644432
6	Central Grampian	4.446109	14.400194	16.644875	- 0.232751	29.049413	32.378388	22.172202
7	Argyll	3.675455	12.382620	26.117508	- 0.232751	34.242806	39.466308	30.837805
8	The Trossachs	3.827726	12.382620	14.391109	- 0.232751	25.013958	27.892180	19.111406
9	Stirlingshire and Fife	2.648027	10.835846	13.137368	- 0.232751	21.593847	24.221321	17.238955
10	South West Scotland	3.005321	11.165296	13.379006	- 0.232751	22.408012	25.083813	17.612373
11	Lothian and Borders	2.905501	11.165296	6.590487	- 0.232751	16.877376	18.195474	10.823854
12	Solway and Cheviot	2.423044	7.313546	7.402865	- 0.232751	13.963422	15.443995	10.095532
13	North East England	3.611493	5.574672	4.549843	- 0.232751	11.478354	12.388323	6.546961
14	North Lancashire and The Lakes	2.485067	5.574672	1.216187	- 0.232751	7.685003	7.928241	3.213305
15	South Lancashire, Yorkshire and Humber	4.018904	1.885191	0.352052	- 0.232751	5.575947	5.646358	0.873377
16	North Midlands and North Wales	3.384821	0.269928		- 0.232751	3.368012	3.368012	- 0.124780
17	South Lincolnshire and North Norfolk	1.810333	0.528105		- 0.232751	2.000066	2.000066	- 0.021509
18	Mid Wales and The Midlands	1.273927	0.853057		- 0.232751	1.723622	1.723622	0.108472
19	Anglesey and Snowdon	5.610335	- 0.068323		- 0.232751	5.322926	5.322926	- 0.260080
20	Pembrokeshire	9.473688	- 4.907724		- 0.232751	5.314758	5.314758	- 2.195841
21	South Wales & Gloucester	6.050596	- 5.023364		- 0.232751	1.799154	1.799154	- 2.242097
22	Cotswold	2.617863	3.820598	- 8.882383	- 0.232751	1.664316	- 3.440793	- 7.586895
23	Central London	- 4.237683	3.820598	- 5.933549	- 0.232751	6.160795	- 7.347505	- 4.638061
24	Essex and Kent	- 4.102577	3.820598		- 0.232751	- 1.278850	- 1.278850	1.295488
25	Oxfordshire, Surrey and Sussex	- 1.124600	- 2.157597		- 0.232751	- 3.083429	- 3.083429	- 1.095790
26	Somerset and Wessex	- 1.931156	- 3.151614		- 0.232751	- 4.685198	- 4.685198	- 1.493397
27	West Devon and Cornwall	- 0.361854	- 5.783941		- 0.232751	- 5.221758	- 5.221758	- 2.546327

Table 4 Generation wider tariffs in 2022/23

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	4.706208	20.831403	20.650809	- 0.899494	36.992484	41.122645	28.083876
2	East Aberdeenshire	3.876399	9.881650	20.650809	- 0.899494	27.402872	31.533034	23.703975
3	Western Highlands	4.387804	17.671200	19.317001	- 0.899494	33.078871	36.942271	25.485987
4	Skye and Lochalsh	- 2.244607	17.671200	19.225691	- 0.899494	26.373412	30.218550	25.394677
5	Eastern Grampian and Tayside	4.726125	13.126446	16.586126	- 0.899494	27.596689	30.913914	20.937210
6	Central Grampian	4.938080	13.965354	17.551499	- 0.899494	29.252068	32.762368	22.238147
7	Argyll	4.332811	11.971910	27.094379	- 0.899494	34.686348	40.105224	30.983649
8	The Trossachs	4.446102	11.971910	15.214779	- 0.899494	25.295959	28.338915	19.104049
9	Stirlingshire and Fife	3.001867	10.643552	14.081620	- 0.899494	21.882511	24.698835	17.439547
10	South West Scotland	4.009667	10.952198	14.320346	- 0.899494	23.328208	26.192277	17.801731
11	Lothian and Borders	3.034435	10.952198	7.728318	- 0.899494	17.079354	18.625017	11.209703
12	Solway and Cheviot	2.495426	7.427106	8.089647	- 0.899494	14.009334	15.627264	10.160995
13	North East England	3.771568	5.774770	5.006052	- 0.899494	11.496732	12.497942	6.416466
14	North Lancashire and The Lakes	2.585738	5.774770	1.601173	- 0.899494	7.586998	7.907233	3.011587
15	South Lancashire, Yorkshire and Humber	4.107392	2.098230	0.395580	- 0.899494	5.202946	5.282062	0.335378
16	North Midlands and North Wales	3.385708	0.549067		- 0.899494	2.925468	2.925468	- 0.679867
17	South Lincolnshire and North Norfolk	1.766784	0.649415		- 0.899494	1.386822	1.386822	- 0.639728
18	Mid Wales and The Midlands	1.167098	0.974951		- 0.899494	1.047565	1.047565	- 0.509514
19	Anglesey and Snowdon	5.831537	0.263271		- 0.899494	5.142660	5.142660	- 0.794186
20	Pembrokeshire	9.656231	- 4.959365		- 0.899494	4.789245	4.789245	- 2.883240
21	South Wales & Gloucester	6.155996	- 5.087984		- 0.899494	1.186115	1.186115	- 2.934688
22	Cotswold	2.644227	3.976449	- 9.113637	- 0.899494	- 2.365017	- 4.187745	- 8.422551
23	Central London	- 4.414260	3.976449	- 6.079252	- 0.899494	- 6.995996	- 8.211847	- 5.388166
24	Essex and Kent	- 4.264800	3.976449		- 0.899494	- 1.983135	- 1.983135	0.691086
25	Oxfordshire, Surrey and Sussex	- 1.118364	- 2.243515		- 0.899494	- 3.812670	- 3.812670	- 1.796900
26	Somerset and Wessex	- 2.053398	- 3.347345		- 0.899494	- 5.630768	- 5.630768	- 2.238432
27	West Devon and Cornwall	- 0.142047	- 6.384412		- 0.899494	- 6.149071	- 6.149071	- 3.453259

Table 5 Generation wider tariffs in 2023/24

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	4.642210	20.132937	22.815048	- 1.598413	37.402185	41.965195	29.269810
2	East Aberdeenshire	3.729960	9.482540	22.815048	- 1.598413	27.969617	32.532627	25.009651
3	Western Highlands	4.270532	17.063149	21.480510	- 1.598413	33.507046	37.803148	26.707357
4	Skye and Lochalsh	- 0.551272	17.063149	23.418530	- 1.598413	30.235658	34.919364	28.645377
5	Eastern Grampian and Tayside	4.595510	12.553349	18.713503	- 1.598413	28.010579	31.753279	22.136430
6	Central Grampian	4.774767	13.369498	19.663026	- 1.598413	29.602373	33.534978	23.412412
7	Argyll	4.107779	11.276119	31.274863	- 1.598413	36.550152	42.805124	34.186898
8	The Trossachs	4.256500	11.276119	17.182641	- 1.598413	25.425095	28.861623	20.094676
9	Stirlingshire and Fife	2.884573	10.083025	16.141070	- 1.598413	22.265436	25.493650	18.575867
10	South West Scotland	3.580495	10.151159	16.195048	- 1.598413	23.059048	26.298057	18.657099
11	Lothian and Borders	2.983860	10.151159	10.069784	- 1.598413	17.562201	19.576158	12.531835
12	Solway and Cheviot	2.235191	7.121880	9.326582	- 1.598413	13.795548	15.660864	10.576921
13	North East England	3.248057	5.660889	5.869826	- 1.598413	10.874216	12.048181	6.535769
14	North Lancashire and The Lakes	2.513352	5.660889	2.209889	- 1.598413	7.211561	7.653539	2.875832
15	South Lancashire, Yorkshire and Humber	3.564028	2.398838	0.861612	- 1.598413	4.573975	4.746297	0.222734
16	North Midlands and North Wales	3.175351	0.594717		- 1.598413	2.052712	2.052712	- 1.360526
17	South Lincolnshire and North Norfolk	0.221491	2.298628		- 1.598413	0.461980	0.461980	- 0.678962
18	Mid Wales and The Midlands	0.589816	2.370168		- 1.598413	0.887537	0.887537	- 0.650346
19	Anglesey and Snowdon	6.785952	- 0.433573		- 1.598413	4.840681	4.840681	- 1.771842
20	Pembrokeshire	10.219978	- 4.958521		- 1.598413	4.654748	4.654748	- 3.581821
21	South Wales & Gloucester	6.626153	- 5.075633		- 1.598413	0.967234	0.967234	- 3.628666
22	Cotswold	3.017531	4.012881	- 9.132321	- 1.598413	- 2.676434	- 4.502898	- 9.125582
23	Central London	- 6.281919	4.012881	- 8.615931	- 1.598413	- 11.562772	- 13.285958	- 8.609192
24	Essex and Kent	- 4.055391	4.012881		- 1.598413	- 2.443499	- 2.443499	0.006739
25	Oxfordshire, Surrey and Sussex	- 1.127945	- 2.210208		- 1.598413	- 4.494524	- 4.494524	- 2.482496
26	Somerset and Wessex	- 1.568899	- 3.553881		- 1.598413	- 6.010417	- 6.010417	- 3.019965
27	West Devon and Cornwall	- 0.013469	- 6.473775		- 1.598413	- 6.763964	- 6.763964	- 4.187923

Table 6 Generation wider tariffs in 2024/25

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	3.642164	21.304738	32.912535	- 3.052436	43.963546	50.546053	38.381994
2	East Aberdeenshire	1.698588	1.907017	32.912535	- 3.052436	26.501794	33.084301	30.622906
3	Western Highlands	3.433365	15.350738	25.661469	- 3.052436	33.190695	38.322988	28.749328
4	Skye and Lochalsh	- 1.526749	15.350738	27.692516	- 3.052436	29.855418	35.393921	30.780375
5	Eastern Grampian and Tayside	5.260410	12.443309	21.600743	- 3.052436	29.443216	33.763364	23.525631
6	Central Grampian	4.304481	12.665956	22.046770	- 3.052436	29.022226	33.431580	24.060716
7	Argyll	3.234347	11.259478	35.471337	- 3.052436	37.566563	44.660830	36.922692
8	The Trossachs	3.280871	11.259478	19.199009	- 3.052436	24.595225	28.435026	20.650364
9	Stirlingshire and Fife	2.133754	10.332427	17.769237	- 3.052436	21.562649	25.116497	18.849772
10	South West Scotland	2.042810	10.310720	17.738367	- 3.052436	21.429644	24.977317	18.810219
11	Lothian and Borders	2.637857	10.310720	11.093322	- 3.052436	16.708655	18.927319	12.165174
12	Solway and Cheviot	1.859269	7.569785	10.011831	- 3.052436	12.872126	14.874492	9.987309
13	North East England	2.647756	6.128402	5.894909	- 3.052436	9.213969	10.392951	5.293834
14	North Lancashire and The Lakes	1.826035	6.128402	2.901768	- 3.052436	5.997735	6.578089	2.300693
15	South Lancashire, Yorkshire and Humber	3.207752	3.327270	0.592597	- 3.052436	3.291210	3.409729	- 1.128931
16	North Midlands and North Wales	2.423090	2.063356	- 0.045531	- 3.052436	0.984914	0.975808	- 2.272625
17	South Lincolnshire and North Norfolk	0.025081	2.852042	- 0.011788	- 3.052436	- 0.755152	- 0.757509	- 1.923407
18	Mid Wales and The Midlands	1.236300	3.228910	- 0.008291	- 3.052436	0.760359	0.758701	- 1.769163
19	Anglesey and Snowdon	2.911346	3.619446	- 0.045531	- 3.052436	2.718042	2.708936	- 1.650189
20	Pembrokeshire	10.008160	- 5.263494		- 3.052436	2.744929	2.744929	- 5.157834
21	South Wales & Gloucester	6.133388	- 5.729039		- 3.052436	- 1.502279	- 1.502279	- 5.344052
22	Cotswold	3.247874	3.561252	- 9.608139	- 3.052436	- 4.642072	- 6.563699	- 11.236074
23	Central London	- 3.570355	3.561252	- 6.718253	- 3.052436	- 9.148392	- 10.492042	- 8.346188
24	Essex and Kent	- 2.560401	3.561252		- 3.052436	- 2.763835	- 2.763835	- 1.627935
25	Oxfordshire, Surrey and Sussex	- 0.764559	- 3.097787		- 3.052436	- 6.295225	- 6.295225	- 4.291551
26	Somerset and Wessex	- 1.507727	- 4.470129		- 3.052436	- 8.136266	- 8.136266	- 4.840488
27	West Devon and Cornwall	- 0.743767	- 8.353923		- 3.052436	- 10.479341	- 10.479341	- 6.394005

Table 7 Generation wider tariffs in 2025/26

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80%	Conventional Low Carbon 80%	Intermittent 40%
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	Load Factor (£/kW)	Load Factor (£/kW)	Load Factor (£/kW)
1	North Scotland	3.095193	22.574888	32.289041	- 3.263235	43.723101	50.180909	38.055761
2	East Aberdeenshire	3.576290	3.018119	32.289041	- 3.263235	28.558783	35.016591	30.233054
3	Western Highlands	3.264373	17.435972	25.140861	- 3.263235	34.062604	39.090777	28.852015
4	Skye and Lochalsh	3.347292	17.435972	31.660782	- 3.263235	39.361460	45.693617	35.371936
5	Eastern Grampian and Tayside	6.303349	13.664784	21.459311	- 3.263235	31.139390	35.431252	23.661990
6	Central Grampian	5.335746	13.733689	21.560925	- 3.263235	30.308202	34.620387	23.791166
7	Argyll	5.236788	11.948683	35.231194	- 3.263235	39.717455	46.763693	36.747432
8	The Trossachs	4.313075	11.948683	18.901484	- 3.263235	25.729974	29.510270	20.417722
9	Stirlingshire and Fife	3.186898	10.792452	17.494382	- 3.263235	22.553130	26.052007	18.548128
10	South West Scotland	3.273522	10.876731	17.590400	- 3.263235	22.783992	26.302072	18.677857
11	Lothian and Borders	3.530029	10.876731	10.342300	- 3.263235	17.242019	19.310479	11.429757
12	Solway and Cheviot	2.888139	7.860882	10.427309	- 3.263235	14.255457	16.340919	10.308427
13	North East England	3.739236	5.977309	5.676046	- 3.263235	9.798685	10.933894	4.803735
14	North Lancashire and The Lakes	2.581054	5.977309	3.162757	- 3.263235	6.629872	7.262423	2.290446
15	South Lancashire, Yorkshire and Humber	4.768576	2.681590	0.081877	- 3.263235	3.716115	3.732490	- 2.108722
16	North Midlands and North Wales	3.390470	2.443887	- 0.042042	- 3.263235	2.048711	2.040303	- 2.327722
17	South Lincolnshire and North Norfolk	0.210896	2.531723	- 0.037918	- 3.263235	- 1.057295	- 1.064879	- 2.288464
18	Mid Wales and The Midlands	1.074678	3.243964	- 0.027836	- 3.263235	0.384345	0.378778	- 1.993485
19	Anglesey and Snowdon	3.394760	3.925795	- 0.042042	- 3.263235	3.238527	3.230119	- 1.734959
20	Pembrokeshire	9.550242	- 5.598850		- 3.263235	1.807927	1.807927	- 5.502775
21	South Wales & Gloucester	5.452625	- 6.054003		- 3.263235	- 2.653812	- 2.653812	- 5.684836
22	Cotswold	2.659088	3.865019	- 10.168283	- 3.263235	- 5.646758	- 7.680415	- 11.885510
23	Central London	- 5.874151	3.865019	- 1.847942	- 3.263235	- 7.523724	- 7.893313	- 3.565169
24	Essex and Kent	- 3.526557	3.865019		- 3.263235	- 3.697777	- 3.697777	- 1.717227
25	Oxfordshire, Surrey and Sussex	- 0.945766	- 2.639674		- 3.263235	- 6.320740	- 6.320740	- 4.319105
26	Somerset and Wessex	- 1.987839	- 4.363028		- 3.263235	- 8.741496	- 8.741496	- 5.008446
27	West Devon and Cornwall	- 1.171085	- 8.467811		- 3.263235	- 11.208569	- 11.208569	- 6.650359

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

The following section provides details of the wider generation tariffs for 2021/22 to 2025/26 and how these could change over the next five years. We have compared the example tariffs for Conventional Carbon generators with an ALF of 80%, Conventional Low Carbon generators with an ALF of 80%, and Intermittent generators with an ALF of 40% for illustration purposes only

The Generation tariffs in the below tables include the potential impact of the TCR, where the generation residual has increased and 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 Ofgem's final decision.

Table 8 Comparison of Conventional Carbon (80%) tariffs

Wider Tariffs for a Conventional Carbon 80% Generator		2021/22	2022/23	2023/24	2024/25	2025/26
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	35.274	36.992	37.402	43.964	43.723
2	East Aberdeenshire	26.633	27.403	27.970	26.502	28.559
3	Western Highlands	32.942	33.079	33.507	33.191	34.063
4	Skye and Lochalsh	26.389	26.373	30.236	29.855	39.361
5	Eastern Grampian and Tayside	27.342	27.597	28.011	29.443	31.139
6	Central Grampian	29.049	29.252	29.602	29.022	30.308
7	Argyll	34.243	34.686	36.550	37.567	39.717
8	The Trossachs	25.014	25.296	25.425	24.595	25.730
9	Stirlingshire and Fife	21.594	21.883	22.265	21.563	22.553
10	South West Scotland	22.408	23.328	23.059	21.430	22.784
11	Lothian and Borders	16.877	17.079	17.562	16.709	17.242
12	Solway and Cheviot	13.963	14.009	13.796	12.872	14.255
13	North East England	11.478	11.497	10.874	9.214	9.799
14	North Lancashire and The Lakes	7.685	7.587	7.212	5.998	6.630
15	South Lancashire, Yorkshire and Humber	5.576	5.203	4.574	3.291	3.716
16	North Midlands and North Wales	3.368	2.925	2.053	0.985	2.049
17	South Lincolnshire and North Norfolk	2.000	1.387	0.462	- 0.755	- 1.057
18	Mid Wales and The Midlands	1.724	1.048	0.888	0.760	0.384
19	Anglesey and Snowdon	5.323	5.143	4.841	2.718	3.239
20	Pembrokeshire	5.315	4.789	4.655	2.745	1.808
21	South Wales & Gloucester	1.799	1.186	0.967	- 1.502	- 2.654
22	Cotswold	- 1.664	- 2.365	- 2.676	- 4.642	- 5.647
23	Central London	- 6.161	- 6.996	- 11.563	- 9.148	- 7.524
24	Essex and Kent	- 1.279	- 1.983	- 2.443	- 2.764	- 3.698
25	Oxfordshire, Surrey and Sussex	- 3.083	- 3.813	- 4.495	- 6.295	- 6.321
26	Somerset and Wessex	- 4.685	- 5.631	- 6.010	- 8.136	- 8.741
27	West Devon and Cornwall	- 5.222	- 6.149	- 6.764	- 10.479	- 11.209

Figure 1 Wider tariffs for a Conventional Carbon (80%) generator

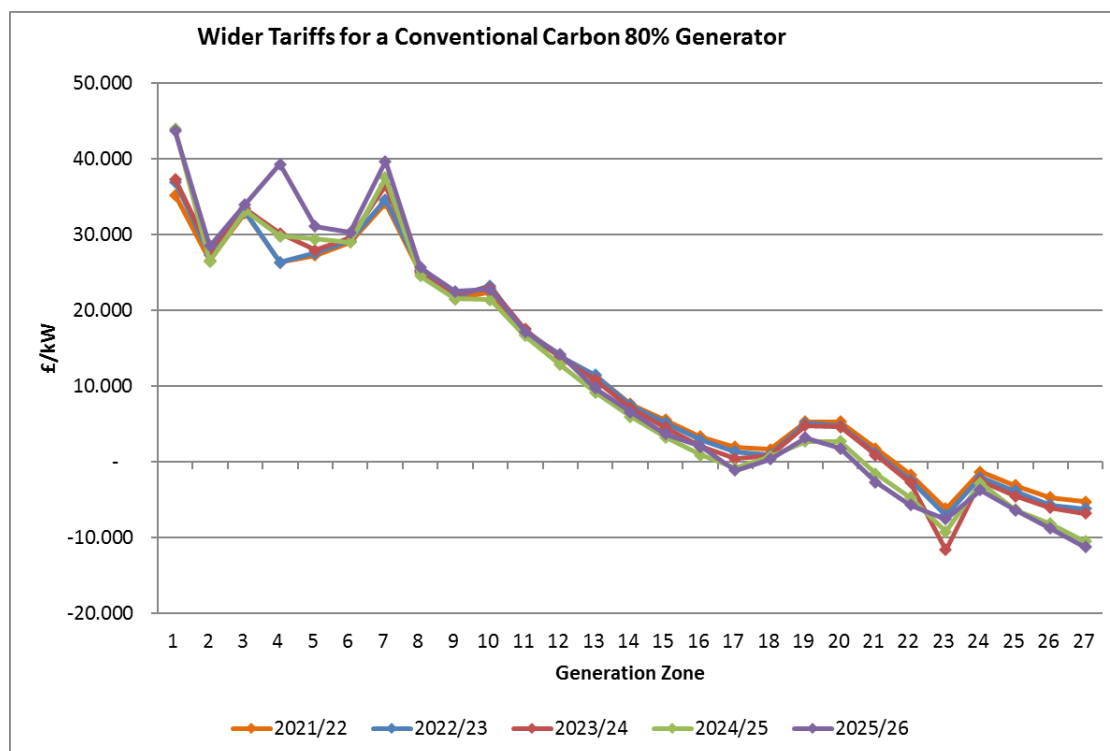


Table 9 Comparison of Conventional Low Carbon (80%) tariffs

Wider Tariffs for a Conventional Low Carbon 80% Generator		2021/22	2022/23	2023/24	2024/25	2025/26
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	39.048	41.123	41.965	50.546	50.181
2	East Aberdeenshire	30.406	31.533	32.533	33.084	35.017
3	Western Highlands	36.583	36.942	37.803	38.323	39.091
4	Skye and Lochalsh	30.011	30.219	34.919	35.394	45.694
5	Eastern Grampian and Tayside	30.447	30.914	31.753	33.763	35.431
6	Central Grampian	32.378	32.762	33.535	33.432	34.620
7	Argyll	39.466	40.105	42.805	44.661	46.764
8	The Trossachs	27.892	28.339	28.862	28.435	29.510
9	Stirlingshire and Fife	24.221	24.699	25.494	25.116	26.052
10	South West Scotland	25.084	26.192	26.298	24.977	26.302
11	Lothian and Borders	18.195	18.625	19.576	18.927	19.310
12	Solway and Cheviot	15.444	15.627	15.661	14.874	16.341
13	North East England	12.388	12.498	12.048	10.393	10.934
14	North Lancashire and The Lakes	7.928	7.907	7.654	6.578	7.262
15	South Lancashire, Yorkshire and Humber	5.646	5.282	4.746	3.410	3.732
16	North Midlands and North Wales	3.368	2.925	2.053	0.976	2.040
17	South Lincolnshire and North Norfolk	2.000	1.387	0.462	0.758	1.065
18	Mid Wales and The Midlands	1.724	1.048	0.888	0.759	0.379
19	Anglesey and Snowdon	5.323	5.143	4.841	2.709	3.230
20	Pembrokeshire	5.315	4.789	4.655	2.745	1.808
21	South Wales & Gloucester	1.799	1.186	0.967	1.502	2.654
22	Cotswold	- 3.441	- 4.188	- 4.503	- 6.564	- 7.680
23	Central London	- 7.348	- 8.212	- 13.286	- 10.492	- 7.893
24	Essex and Kent	- 1.279	- 1.983	- 2.443	- 2.764	- 3.698
25	Oxfordshire, Surrey and Sussex	- 3.083	- 3.813	- 4.495	- 6.295	- 6.321
26	Somerset and Wessex	- 4.685	- 5.631	- 6.010	- 8.136	- 8.741
27	West Devon and Cornwall	- 5.222	- 6.149	- 6.764	- 10.479	- 11.209

Figure 2 Wider tariffs for a Conventional Low Carbon (80%) generator

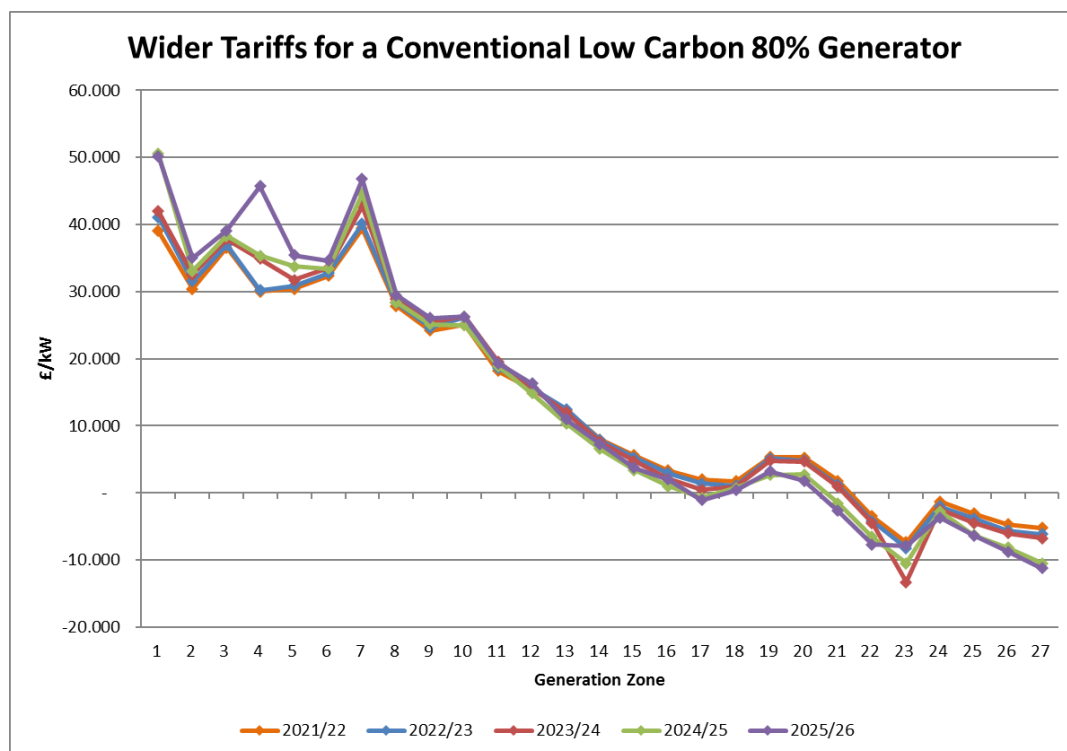
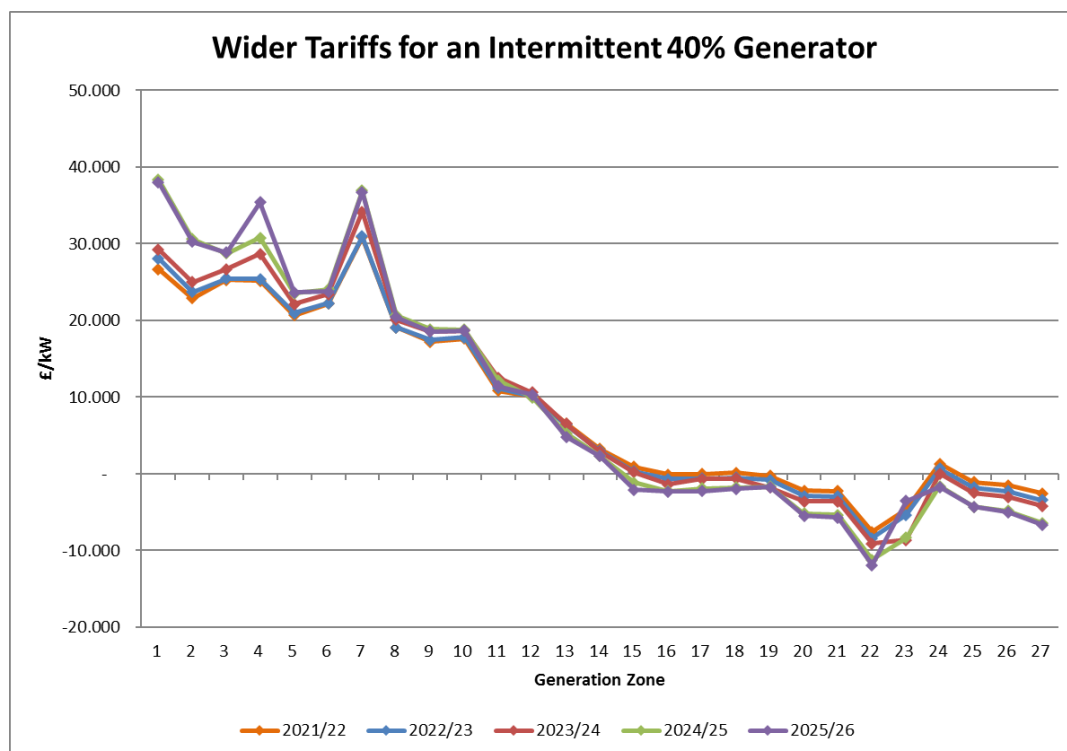


Table 10 Comparison of Intermittent (40%) tariffs

Wider Tariffs for an Intermittent 40% Generator		2021/22	2022/23	2023/24	2024/25	2025/26
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	26.670	28.084	29.270	38.382	38.056
2	East Aberdeenshire	22.894	23.704	25.010	30.623	30.233
3	Western Highlands	25.288	25.486	26.707	28.749	28.852
4	Skye and Lochalsh	25.191	25.395	28.645	30.780	35.372
5	Eastern Grampian and Tayside	20.644	20.937	22.136	23.526	23.662
6	Central Grampian	22.172	22.238	23.412	24.061	23.791
7	Argyll	30.838	30.984	34.187	36.923	36.747
8	The Trossachs	19.111	19.104	20.095	20.650	20.418
9	Stirlingshire and Fife	17.239	17.440	18.576	18.850	18.548
10	South West Scotland	17.612	17.802	18.657	18.810	18.678
11	Lothian and Borders	10.824	11.210	12.532	12.165	11.430
12	Solway and Cheviot	10.096	10.161	10.577	9.987	10.308
13	North East England	6.547	6.416	6.536	5.294	4.804
14	North Lancashire and The Lakes	3.213	3.012	2.876	2.301	2.290
15	South Lancashire, Yorkshire and Humber	0.873	0.335	0.223	1.129	2.109
16	North Midlands and North Wales	- 0.125	- 0.680	- 1.361	- 2.273	- 2.328
17	South Lincolnshire and North Norfolk	- 0.022	- 0.640	- 0.679	- 1.923	- 2.288
18	Mid Wales and The Midlands	0.108	- 0.510	- 0.650	- 1.769	- 1.993
19	Anglesey and Snowdon	- 0.260	- 0.794	- 1.772	- 1.650	- 1.735
20	Pembrokeshire	- 2.196	- 2.883	- 3.582	- 5.158	- 5.503
21	South Wales & Gloucester	- 2.242	- 2.935	- 3.629	- 5.344	- 5.685
22	Cotswold	- 7.587	- 8.423	- 9.126	- 11.236	- 11.886
23	Central London	- 4.638	- 5.388	- 8.609	- 8.346	- 3.565
24	Essex and Kent	1.295	0.691	0.007	- 1.628	- 1.717
25	Oxfordshire, Surrey and Sussex	- 1.096	- 1.797	- 2.482	- 4.292	- 4.319
26	Somerset and Wessex	- 1.493	- 2.238	- 3.020	- 4.840	- 5.008
27	West Devon and Cornwall	- 2.546	- 3.453	- 4.188	- 6.394	- 6.650

Figure 3 Wider tariffs for an Intermittent (40%) generator



Locational changes

Locational tariffs are forecasted to increase in Scotland due to an increase in renewable generation. We have also anticipated a plateau in conventional generation over the five years of the forecast, which causes little change in tariffs in zones 8-18.

In England and Wales, the increasingly negative residual offsets increase in locational tariffs. There are some fluctuations in zones 22-27 due to generation connecting in later years.

To view the changes in generation in each zone, please see Table 42 on page 73 and Table 43 on page 86.

Residual changes

The residual tariff would significantly increase from the current financial year from £-4.85/kW to £-0.23/kW in 2021/22 due to the expected implementation of CMP317/327 in April 2021. The residual then decreases again over the five-year period, becoming more negative due to the increase each year in the wider tariffs. This is driven by the increasing charging base. For a full breakdown of the generation revenues, please see Table 29 on page 38.

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 five-year view, we have applied RPI to the onshore substation tariffs set in RIIO-1. Over the coming months, we would refine the RIIO-2 parameters with updated TO's data and provide more accurate value in our next forecast. Our initial observations are that, with the data that we have collated to date, the Local Substation Tariffs for RIIO-2 would be lower than the current RPI uplifted RIIO-1 values.

Since the March forecast the local substation tariff has reduced due to a lower forecasted RPI inflation value for 2021/22. We have published the inflation indices in Table 26 on page 35.

Table 11 Local substation tariffs

2021/22 Local substation tariff (£/kW)				
Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.205851	0.117760	0.084849
<1320 MW	Redundancy	0.453473	0.280567	0.204051
>=1320 MW	No redundancy	-	0.369230	0.267028
>=1320 MW	Redundancy	-	0.606181	0.442462

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 2021/22 March Tariffs. The 2021/22- 2025/26 Onshore local circuit tariffs are listed in below in Table 12.

Table 12 Onshore local circuit tariffs

Connection Point	2021/22 (£/kW)	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)
Aberarder	1.696824	1.738276	1.790439	1.844152	1.898429
Aberdeen Bay	2.673272	2.738577	2.820757	2.905380	2.990892
Achrach	- 2.620252	- 2.683967	- 2.764056	- 2.847272	- 2.931159
Aigas	0.670565	0.686947	0.707561	0.728788	0.750237
An Suidhe	- 0.982228	- 1.005926	- 1.035665	- 1.067024	- 1.098515
Arecleoch	2.129462	2.181483	2.246945	2.314354	2.382470
Baglan Bay	0.780164	0.799223	- 0.158400	- 0.163139	- 0.167935
Beinneun Wind Farm	1.539935	1.577549	1.624886	1.673630	1.722885
Beaw Field				64.543199	67.433697
Bhlaraidh Wind Farm	0.661978	0.678150	0.698500	0.719455	0.740630
Black Hill	1.592263	1.631160	1.680109	1.730512	1.781445
Black Law	1.791561	1.835327	1.890402	1.947114	2.004422
BlackCraig Wind Farm	6.454244	6.611914	6.810327	7.014636	7.221092
BlackLaw Extension	3.799237	3.892049	4.008843	4.129108	4.250636
Branxton			0.402328	0.416041	0.428874
Clash Gour				1.227106	0.254928
Clyde (North)	0.112440	0.115187	0.118643	0.122203	0.125799
Clyde (South)	0.130032	0.133208	0.137205	0.141322	0.145481
Corriegarth	2.970302	3.042864	3.134175	3.228200	3.323213
Corriemoillie	1.707529	1.749068	1.801539	1.855568	1.910159
Coryton	0.050975	0.052439	0.053914	0.055627	0.057289
Costa Head				47.318401	48.710890
Creag Riabhach		3.523316	3.629044	3.737916	3.847931
Cruachan	1.871050	1.916814	1.974373	2.033679	2.093533
Crystal Rig	0.140321	0.144440	0.150851	0.156138	0.160997
Culligran	1.777014	1.820425	1.875053	1.931304	1.988147
Deanie	2.919380	2.990698	3.080443	3.172857	3.266241
Dersalloch	2.469724	2.530057	2.605979	2.684159	2.763159
Dinorwig	2.459954	2.520048	2.595671	2.673541	2.752229
Dorenell	2.151707	2.204271	2.270417	2.338529	2.407357
Dumnaglass	1.162066	1.190454	1.226177	1.262963	1.300134
Dunhill	1.468540	1.504415	1.549560	1.596046	1.643021
Dunlaw Extension	1.548177	1.586971	1.635212	1.685247	1.734856
Edinbane	7.018600	7.190069	7.406127	7.628315	1.058256
Elchies				1.944472	2.001702
Energy Isle				69.300546	72.331064
Enoch Hill			0.669662	0.849526	0.874530
Ewe Hill	2.495409	2.556369	2.633081	2.712073	2.791896
Fallago	0.446800	0.458965	0.476368	0.492043	0.507010

Connection Point	2021/22 (£/kW)	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)
Farr	3.655572	3.744874	3.857251	3.972968	4.089902
Fernoch	4.509963	4.620138	4.758782	4.901546	5.045811
Ffestiniogg	0.259396	0.265733	0.273707	0.281918	0.290216
Finlarig	0.328297	0.336316	0.346409	0.356801	0.367302
Foyers	0.300324	0.307661	0.316893	0.326400	0.336006
Galawhistle	3.587584	3.675225	3.785512	3.899077	4.013836
Gills Bay				2.806235	2.888829
Glen Kyllachy	- 0.468995	- 0.480452	- 0.494870	- 0.509716	- 0.524718
Glendoe	1.885932	1.932004	1.989980	2.049679	2.110006
Glenglass	4.933204	5.053717	5.205371	5.361532	5.519334
Glenshero				0.068323	0.070334
GLMU PS				0.744932	0.766857
Gordonbush	0.089748	0.112074	0.127529	0.160492	0.206859
Griffin Wind	9.958452	10.200746	10.506631	10.822444	11.140325
Hadyard Hill	2.837888	2.907214	2.994455	3.084289	3.175066
Harestanes	2.591055	2.655394	2.734760	2.818039	2.901382
Hartlepool	0.211097	0.216751	0.279587	0.288222	0.296817
Hesta Head				57.026127	58.704336
Invergarry	0.375196	0.384362	0.395896	0.407773	0.419774
Kergord				58.966372	61.692733
Kilgallioch	1.079063	1.105423	1.138595	1.172753	1.207269
Kilmorack	0.202487	0.207433	0.213658	0.220068	0.226545
Kype Muir	1.520761	1.557911	1.604661	1.652801	1.701447
Langage	- 0.347274	- 0.355838	- 0.366461	- 0.377361	- 0.388284
Limekilns		0.640603	0.659826	0.679621	0.699624
Lochay	0.375196	0.384362	0.395896	0.407773	0.419774
Luichart	0.589714	0.603945	0.622054	0.640697	0.659532
Marchwood	0.391269	0.400674	0.412704	- 0.256757	- 0.264312
Mark Hill	0.897708	0.919638	0.947234	0.975651	1.004367
Middle Muir	2.032312	2.081959	2.144435	2.208768	2.273777
Middleton	0.153069	0.157837	0.160906	- 0.006164	- 0.005828
Millbrook		0.411796	0.424636	0.437789	0.450544
Millennium Wind	1.872516	1.918255	1.975816	2.035087	2.094980
Moffat	0.194491	0.200284	0.205976	0.213392	0.220074
Mossford	2.953820	3.025804	3.116588	3.210068	3.304525
Mossy Hill				62.024667	64.841040
Nant	2.573124	- 1.290501	- 1.329230	- 1.369110	- 1.409411
Necton	- 0.362064	- 0.370203	1.215292	0.527643	0.543001
New Deer	0.287311	0.294395	0.303232	0.313542	0.321723
Porters Wood					- 0.699636
Progress Power		0.125250	0.129666	0.135410	0.139494
Rhigos	0.106031	0.108656	0.111930	0.115304	0.118704
Rocksavage	0.018147	0.018591	0.019148	0.019723	0.020303
Saltend	0.017789	0.018224	- 0.002221	- 0.002288	- 0.002356
South Humber Bank	- 0.191238	- 0.195894	- 0.201772	- 0.207812	- 0.213916
Spalding	0.291374	0.299080	0.307787	0.317339	0.326835
Strathbrora	- 0.032447	- 0.014582	- 0.003783	0.021847	0.062330
Strathy Wind	1.802485	1.862187	1.927394	2.011286	2.099525
Stronelairg	1.097161	1.124890	1.159540	1.208056	1.231766
Wester Dod	0.489202	0.501844	0.518979	0.535310	0.551329
Whitelee	0.108813	0.111471	0.114816	0.118261	0.121741
Whitelee Extension	0.302500	0.309890	0.319189	0.328765	0.338441

As part of their connection offer, generators can make 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 on these one-off charges, please see CUSC sections 2.14.4, 14.4, and 14.15.15.

Table 13 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	Corriearth 132kV	4km Cable	4km OHL	Corriearth
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
Enoch Hill 132kV	New Cumnock 132kV	5km of Cable	5km of OHL	Enoch Hill
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 OFTO.

Please note that all offshore local 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. We have published an open letter (Reflecting variations in OFTO revenue in Offshore Local TNUoS Tariffs) on our webpage⁶. It explains how the offshore local tariffs are reset for the new price control.

The indicative Offshore Substation Discount has now been calculated for RIIO2 and is included in the Offshore Local Substation Tariffs presented below. This value will be further refined and incorporated in our future forecasts as more input data becomes available. Each tariff has also decreased slightly in line with our updated inflation forecast.

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

Table 14 Offshore local tariffs 2021/22

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.860362	46.745901	1.160765
Burbo Bank	11.096526	21.420771	-
Dudgeon	16.285326	25.527890	-
Gallopier	16.601223	26.236091	-
Greater Gabbard	16.480033	38.103364	-
Gunfleet	19.327148	17.810471	3.328879
Gwynt Y Mor	20.507799	20.271496	-
Humber Gateway	11.959852	27.442117	-
Lincs	17.067160	67.060926	-
London Array	11.474417	39.309493	-
Ormonde	27.219353	50.856510	0.405284
Race Bank	9.939735	27.553210	-
Robin Rigg	- 0.585205	33.893199	10.859165
Robin Rigg West	- 0.585205	33.893199	10.859165
Sheringham Shoal	25.471365	29.984861	0.651783
Thanet	19.443486	36.405353	0.876405
Walney 1	23.511515	46.981548	-
Walney 2	21.879971	44.503267	-
Walney 3	10.060437	20.359385	-
Walney 4	10.060437	20.359385	-
West of Duddon Sands	8.944809	44.550087	-
Westermest Rough	18.340048	31.190626	-

⁶ Alternatively, the document can be accessed directly using the following link:
<https://www.nationalgrideso.com/document/94076/download>

A nighttime photograph of the London skyline. The Gherkin building is prominently featured in the center, illuminated with warm yellow lights. To its left, the Shard is visible, also lit up. In the foreground, a large, dark building with many windows is visible, some of which are lit. A street with a few cars and pedestrians is visible in the lower right corner. A large white semi-circle is overlaid on the bottom left of the image, containing the number 3 and the title text.

3

Demand tariffs

Half-Hourly, Non-Half-Hourly, Non-Locational Banded tariffs and the Embedded Export Tariff

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).

For 2021/22, the current calculation methodology for demand tariffs remains the same. As of 2022/23, through the implementation of TDR there will be changes to the demand tariffs i.e. the existing non-locational element in demand tariffs (the demand residual) will be replaced with a new set of £/site non-locational demand tariffs. The demand residual tariffs will be based on banding and applied to final demand. Final demand is the consumption used for purposes other than to operate a generating station, or to store and export. The methodology for demand locational tariffs would continue as it, however flooring on negative locational tariffs is being considered and assessed by the CMP343 workgroup.

In this report, we have calculated demand tariffs for 2022/23 – 2025/26 under the proposed TDR, and assumed flooring on negative demand locational tariffs (which will continue to apply on the triad HH demand and 4-7pm NHH demand). For more information on the details of CMP343 please refer to the workgroup reports published on the ESO's website.⁷

As a confirmation, the Small Generator Discount no longer applies for 2021/22 onwards, due to it being discontinued at the end of 2020/21.

Table 15 HH, NHH and EET Summary

HH Tariffs	2021/22	2022/23	2023/24	2024/25	2025/26
Average Tariff (£/kW)	44.81	2.18	2.16	2.08	2.28
Residual (£/kW)	46.55	-	-	-	-
EET	2021/22	2022/23	2023/24	2024/25	2025/26
Average Tariff (£/kW)	1.86	2.04	2.10	2.10	2.32
Phased residual (£/kW)	-	-	-	-	-
AGIC (£/kW)	2.29	2.34	2.41	2.49	2.49
Total Credit (£m)	13.60	13.56	13.43	13.95	14.33
NHH Tariffs	2021/22	2022/23	2023/24	2024/25	2025/26
Average (p/kWh)	5.69	0.27	0.26	0.26	0.28

For 2022/23 onwards, we have assumed 21 bandings and unmetered demand for the demand residual tariffs. The banding scenario is based on 4 transmission connected bands to provide the greatest granularity of data. Please note that there are also alternatives with 1 and 2 transmission connected bands discussed in the CMP343 workgroup. We will incorporate the approved methodology in our future forecasts when the final decision is confirmed.

⁷ <https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp343>.

Table 16 Non-Locational banded charges

Band	Tariff	2021/22	2022/23	2023/24	2024/25	2025/26
Domestic	£/Site per year		28.18	29.85	30.97	31.81
LV_NoMIC_1			13.66	14.47	15.01	15.42
LV_NoMIC_2			69.77	73.90	76.66	78.76
LV_NoMIC_3			163.42	173.10	179.56	184.47
LV_NoMIC_4			487.42	516.27	535.55	550.19
LV1			1013.47	1073.47	1113.54	1143.99
LV2			1687.82	1787.74	1854.48	1905.19
LV3			2621.57	2776.76	2880.43	2959.19
LV4			5894.17	6243.10	6476.18	6653.26
HV1			4221.63	4471.55	4638.49	4765.32
HV2			14617.99	15483.37	16061.42	16500.60
HV3			28437.68	30121.18	31245.71	32100.08
HV4			70056.57	74203.88	76974.17	79078.91
EHV1			24595.92	26051.99	27024.60	27763.54
EHV2			146997.12	155699.27	161512.07	165928.37
EHV3			313355.45	331905.92	344297.13	353711.41
EHV4			842667.28	892552.74	925874.84	951191.49
T-Demand1			127818.59	135385.38	140439.79	144279.90
T-Demand2			453761.31	480623.74	498567.10	512199.67
T-Demand3			892643.23	945487.25	980785.58	1007603.68
T-Demand4			2690673.70	2849960.18	2956359.11	3037196.29
Unmetered demand	p/kWh per year					
Unmetered	p/kWh per year		0.832403	0.881681	0.914597	0.939606

8. Forecast Tariffs for 2021/22

There have been various updates since our March forecast that have resulted in an overall decrease to the demand tariffs for 2021/22. Both HH and NHH tariffs have seen small adjustments, with the average HH tariff reducing by £0.47/kW to £44.79/kW and NHH by 0.03p/kWh to 5.68p/kWh. The two key factors for this change is due to an updated demand charging base and reduced overall revenue from demand.

For HH demand, there is a slight increase in Gross Triad Demand, but due to a forecasted higher volume of Embedded Export, Net Triad Demand has seen an overall reduction.

For NHH demand, there is an increase in NHH charging base, resulting in a reduction in the NHH tariffs. The EET has seen the largest proportional change since the March forecast with the average tariff expected to decrease by £0.66/kW to £1.86/kW. This is due to the reduction in the AGIC which has been re-calculated as part of the RIIO-2 parameter refresh.

Table 17 HH, NHH and EET Summary (2021/22 Forecast variation)

HH Tariffs	2021/22 March	2021/22 August	Change
Average Tariff (£/kW)	45.257946	44.812728	-0.445218
Residual (£/kW)	46.816636	46.554085	-0.262551
EET	2021/22 March	2021/22 August	Change
Average Tariff (£/kW)	2.516587	1.859122	-0.657465
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	3.513565	2.287880	-1.225685
Embedded Export Volume (GW)	6.819955	7.312920	0.492965
Total Credit (£m)	17.163009	13.595610	-3.567399
NHH Tariffs	2021/22 March	2021/22 August	Change
Average (p/kWh)	5.716624	5.690194	-0.026430

9. Half-Hourly demand tariffs

The upcoming implementation of TDR via CMP343 will have a significant impact on both the HH and NHH tariffs due to the new charging methodology for the demand residual tariffs from 2022/23 onwards. For HH demand tariffs, the introduction of this methodology will replace the current demand residual, which is a £/kW charge based on the average demand taken over the three triad periods. Going forwards the demand residual tariff will be a £/site charge based on bandings. The locational charges will still be based on average demand taken over the triad periods. The HH demand tariffs methodology has stayed the same to the current financial year 2021/22. Table 17 shows the forecast HH tariffs for 2021/22.

From 2022/23, the changes in the average locational HH tariffs remain fairly consistent with the average locational tariff reducing year or year, up until 2025/26 when the average locational tariff increases to £0.28/kW.

We have assumed that locational tariffs will be floored at £0/kW, although this is still subject to the outcome of CMP343. This has caused the locational tariffs for zones 1 to 7 to be £0/kW. Small fluctuations can be seen in the remaining zones that have not been floored. These fluctuations are within the normal bounds, but due to the removal of the residual element these variations will be more prominent in comparison.

Table 18 Gross Half-Hourly locational demand tariffs by demand zone (5-year view)

Zone	Zone Name	2021/22 (£/kW)	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	-	-	-	-	-
8	Midlands	0.913192	0.643733	0.427801	0.646652	-
9	Eastern	1.443548	1.505102	1.577970	0.740827	1.027628
10	South Wales	-	-	-	-	0.339370
11	South East	4.620170	4.729457	4.489555	4.692284	4.946248
12	London	6.701361	6.856094	7.181561	6.091014	7.471724
13	Southern	6.077072	6.269121	6.132991	6.540061	6.587823
14	South Western	5.375289	5.536007	5.213821	6.742072	7.245279

From 2022/23, through the implementation of TDR, the demand residual tariffs would be based on a set of £/site/year bandings and applied to final demand. Final demand is the consumption used for purposes other than to operate a generating station, or to store and export. Table 16 lists the demand residual tariffs for 2022/23 – 2025/26.

Compared to our March forecast, the HH demand tariff for 2021/22 has decreased across all zones, excluding Zone 1 which has seen a slight increase.

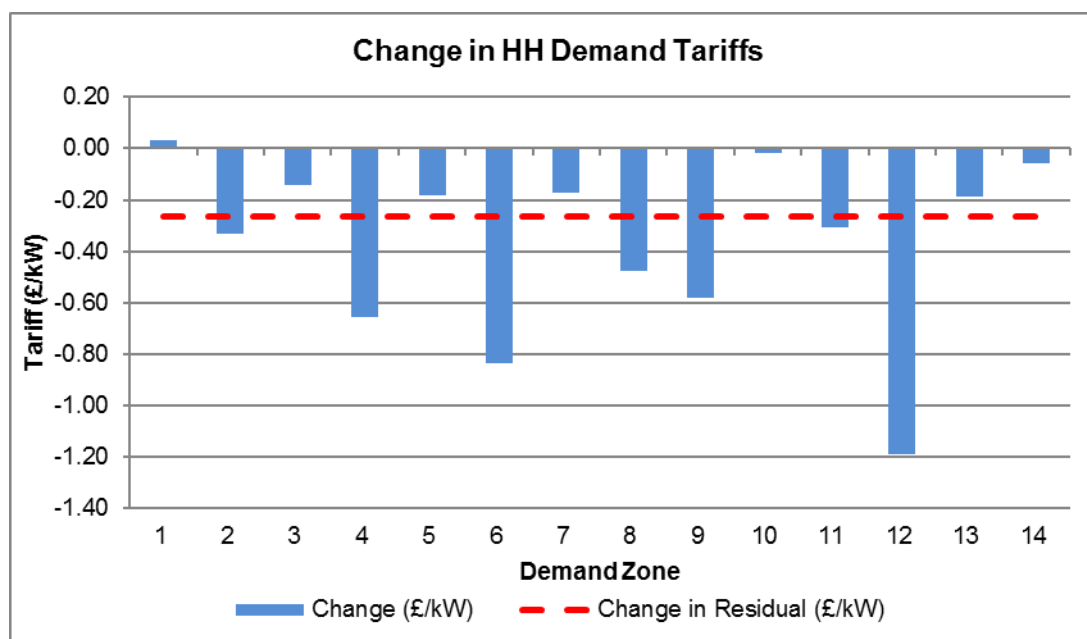
The level of gross HH chargeable demand has decreased by 0.56GW in comparison to the 2021/22 March forecast and is currently forecasted at 18.9GW. This reduction does not take into consideration, the potential impact of COVID-19 in 2021/22 but is reflective of updated demand forecast simulations and adjustments made related to CMP266. CMP266⁸ seeks to prevent double charging of TNUoS for a meter electing to be HH settled, all demand within Measurement Class F & G will be charged under the TNUoS NHH methodology until 2023.

⁸ https://www.ofgem.gov.uk/system/files/docs/2016/12/cmp266_decision.pdf

Table 19 Half-Hourly demand tariffs (2021/22 Forecast variation)

Zone	Zone Name	2021/22 March (£/kW)	2021/22 August (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	15.013659	15.045719	0.032060	-0.262551
2	Southern Scotland	22.823089	22.489331	-0.333758	-0.262551
3	Northern	35.205172	35.064719	-0.140453	-0.262551
4	North West	41.853367	41.194336	-0.659031	-0.262551
5	Yorkshire	42.705231	42.524945	-0.180286	-0.262551
6	N Wales & Mersey	44.132320	43.295059	-0.837261	-0.262551
7	East Midlands	46.383978	46.211767	-0.172211	-0.262551
8	Midlands	47.942227	47.467277	-0.474950	-0.262551
9	Eastern	48.577436	47.997633	-0.579803	-0.262551
10	South Wales	45.290920	45.274604	-0.016316	-0.262551
11	South East	51.480819	51.174255	-0.306564	-0.262551
12	London	54.446552	53.255446	-1.191106	-0.262551
13	Southern	52.819783	52.631157	-0.188626	-0.262551
14	South Western	51.987570	51.929374	-0.058196	-0.262551

Figure 4 Changes to gross Half-Hourly demand tariffs (2021/22 Forecast variation)



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

10. Embedded Export Tariffs (EET)

The EET were introduced in 2018/19 to replace the “Triad benefit”. It is designed to make credit payment to embedded generators (who are not eligible to be charged generation TNUoS tariffs with TEC lower than 100MW) for their metered exports over the triad periods.

These embedded generators are paid either directly by the ESO or through their supplier when the initial demand reconciliation has been completed in accordance with CUSC (see 14.17.19 onwards). The payment to the EET is recovered through demand revenue, which will affect the price of HH and NHH demand tariffs.

Table 20 and Figure 6 show the forecasted Embedded Export Tariffs by zone in the years 2021/22 to 2025/26.

Table 20 Embedded Export Tariffs 2021/22 to 2025/26

Zone	Zone Name	2021/22 (£/kW)	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	1.945563	1.853183	1.879169	1.913014	1.598662
8	Midlands	3.201072	2.987504	2.841905	3.133179	2.552564
9	Eastern	3.731428	3.848873	3.992074	3.227354	3.587339
10	South Wales	1.008400	1.016376	0.608455	1.549460	2.899081
11	South East	6.908051	7.073228	6.903659	7.178811	7.505959
12	London	8.989242	9.199865	9.595665	8.577541	10.031435
13	Southern	8.364952	8.612892	8.547095	9.026588	9.147534
14	South Western	7.663170	7.879778	7.627925	9.228599	9.804990

These tariffs include:

Phased residual (£/kW)	-	-	-	-	-
AGIC (£/kW)	2.287880	2.343771	2.414104	2.486527	2.559711

Figure 5 Embedded Export Tariffs 2021/22 to 2025/26

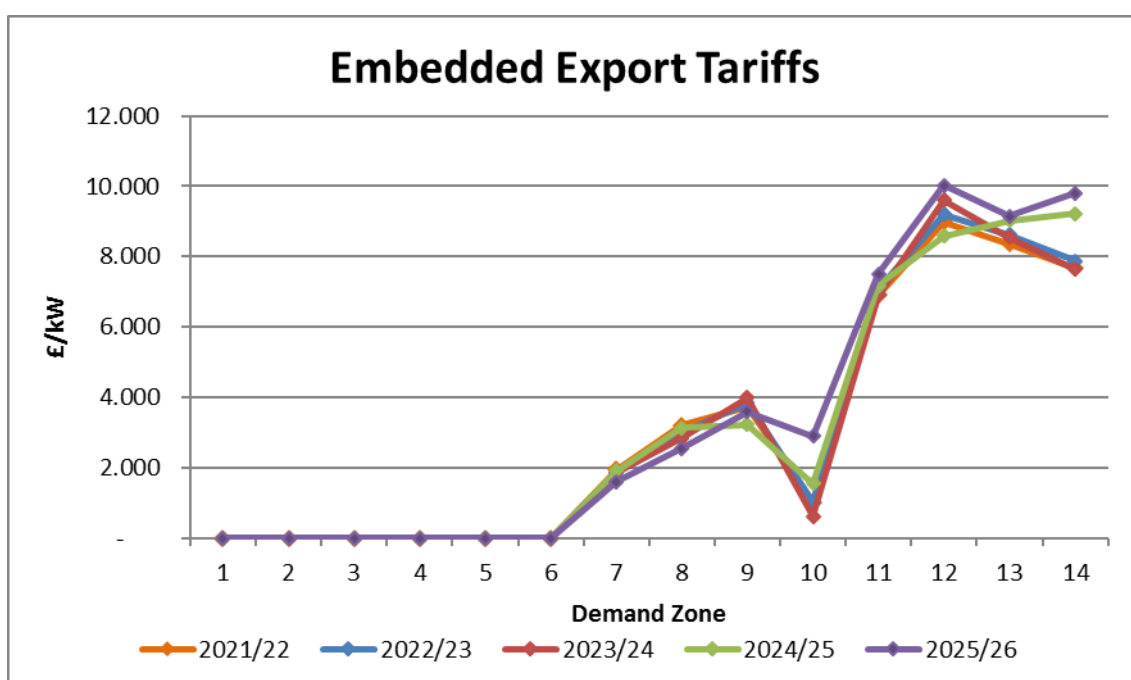


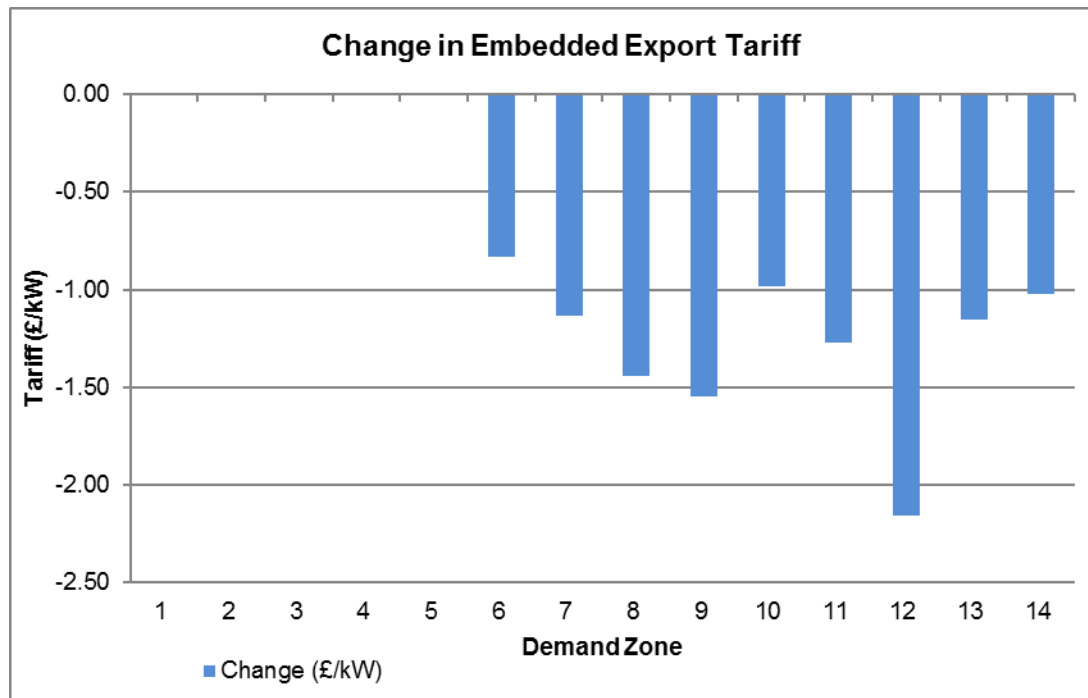
Table 21 and Figure 6 show the forecasted Embedded Export Tariffs and variance from the March forecast for 2021/22.

Table 21 Embedded Export Tariffs (2021/22 Forecast Variation)

Zone	Zone Name	2021/22 March (£/kW)	2021/22 August (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	0.829249	-	-0.829249
7	East Midlands	3.080907	1.945563	-1.135344
8	Midlands	4.639156	3.201072	-1.438084
9	Eastern	5.274364	3.731428	-1.542936
10	South Wales	1.987848	1.008400	-0.979448
11	South East	8.177748	6.908051	-1.269697
12	London	11.143481	8.989242	-2.154239
13	Southern	9.516711	8.364952	-1.151759
14	South Western	8.684499	7.663170	-1.021329

Zone 6 EET – N Wales & Mersey is now floored at £0/kW for 2021/22.

Figure 6 Embedded export tariff changes (2021/22 Forecast Variation)



In this forecast, the key change to the EET is the updated AGIC. In the March forecast, the AGIC was based on an inflated RIIO-1 figure for 2021/22, which was forecasted at £3.51/kW. The latest view of the AGIC is currently £2.29/kW, a reduction of £1.22/kW. Subsequently to this, there has been a large decrease in the average EET tariff for 2021/22 compared to the March forecast, with a decrease of £0.66/kW to £1.86/kW. With these changes, the forecasted EET revenue has decreased significantly to £13.6m, down ~£3.6m from the March Forecast (£17.2m). In addition,

the EET charging base for 2021/22 has increased to 7.3GW, an increase of 0.5GW in comparison to the March forecast.

The impact of the AGIC reduction will also be seen in the following years (2022/23 – 2025/26), resulting in the average EET and EET revenue increasing slowly.

11. Non-Half-Hourly demand tariffs

As with HH demand, the new TDR methodology will also significantly impact the NHH tariffs, introducing a new set of bandings for the demand residual tariffs. NHH demand users will be subject to a p/kWh charge based on their consumption between 4pm-7pm every day of the year as they are currently, though the p/kWh charge is significantly lower from 2022/23 with the implementation of the TDR. NHH demand users will then also be subject to an additional £/site charge which is the demand residual charge. For the demand residual tariffs for 2022/23 to 2025/26, please see Table 16.

Table 22 below shows what the tariffs would be for NHH for the next five years with the TDR being implemented in 2022/23. We have assumed that zonal tariffs will be floored at £0/kW, although this is still subject to the outcome of CMP343.

Table 22 Non-half hourly demand tariffs from 2021/22 to 2025/26

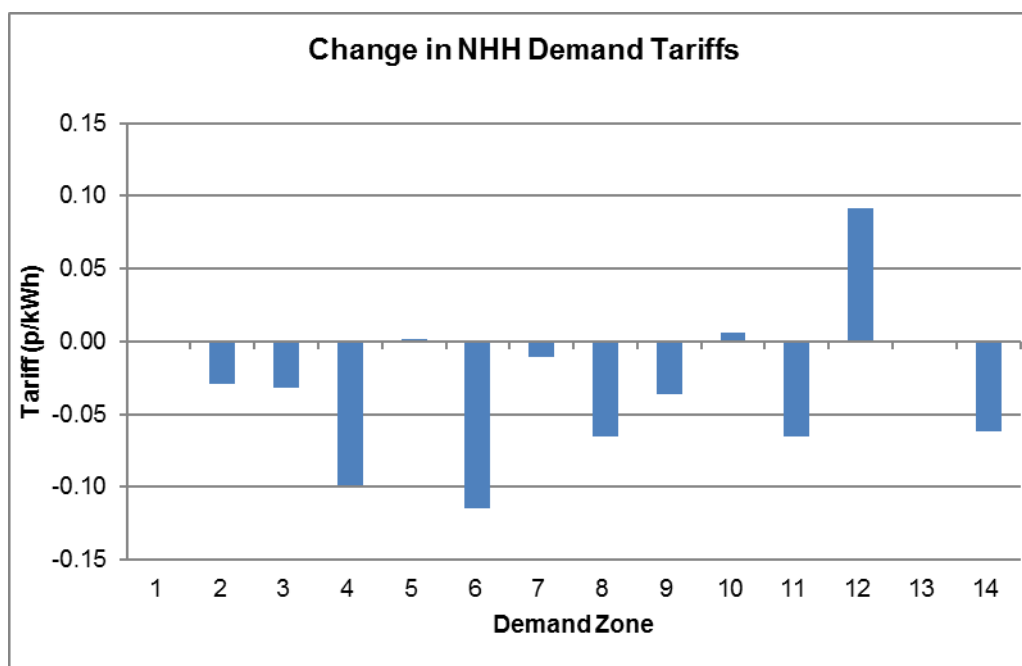
Zone	Zone Name	2021/22 (p/kWh)	2022/23 (p/kWh)	2023/24 (p/kWh)	2024/25 (p/kWh)	2025/26 (p/kWh)
1	Northern Scotland	2.045854	-	-	-	-
2	Southern Scotland	2.913497	-	-	-	-
3	Northern	4.357130	-	-	-	-
4	North West	5.207812	-	-	-	-
5	Yorkshire	5.257421	-	-	-	-
6	N Wales & Mersey	5.393179	-	-	-	-
7	East Midlands	5.897278	-	-	-	-
8	Midlands	6.131826	0.083836	0.055837	0.084459	-
9	Eastern	6.576802	0.207804	0.217531	0.102495	0.142358
10	South Wales	5.259660	-	-	-	0.038944
11	South East	7.062878	0.658112	0.627588	0.654999	0.692279
12	London	5.580801	0.726469	0.751695	0.631334	0.784324
13	Southern	6.795285	0.815947	0.798417	0.850915	0.859251
14	South Western	7.157069	0.770740	0.726852	0.942932	1.013372

The average NHH tariff for 2021/22 is currently forecasted at 5.69p/kWh, a reduction of 0.02p/kWh from the March forecast. Although there has been an overall reduction in revenue to be recovered through demand in 2021/22, a lower proportion of that reduction is attributed to NHH revenue. This is due to the adjustments made to the HH and NHH charging bases for this forecast to incorporate CMP266. This table and chart below show the difference from our March forecast.

Table 23 Non-Half-Hourly demand tariffs (2021/22 Forecast Variation)

Zone	Zone Name	2021/22 March (p/kWh)	2021/22 August (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.044827	2.045854	0.001027
2	Southern Scotland	2.942453	2.913497	-0.028956
3	Northern	4.389070	4.357130	-0.031940
4	North West	5.306145	5.207812	-0.098333
5	Yorkshire	5.255794	5.257421	0.001627
6	N Wales & Mersey	5.508067	5.393179	-0.114888
7	East Midlands	5.907568	5.897278	-0.010290
8	Midlands	6.197093	6.131826	-0.065267
9	Eastern	6.612843	6.576802	-0.036041
10	South Wales	5.253280	5.259660	0.006380
11	South East	7.128290	7.062878	-0.065412
12	London	5.488955	5.580801	0.091846
13	Southern	6.796496	6.795285	-0.001211
14	South Western	7.218883	7.157069	-0.061814

Figure 7 Changes to Non-Half Hourly demand tariffs





4

Overview of data input

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

12. Changes affecting the locational element of tariffs

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

- Contracted generation and nodal demand;
- Local and MITS circuits as in the ETYS;
- Inflation;
- Locational security factor

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2021/22 period onwards, which can be found on the TEC register.⁹ The contracted TEC volumes are based on the July 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 and use the TEC as published in the TEC register as of 31st October 2020, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 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 24 Generation contracted, modelled and chargeable TEC

Best View	2021/22	2022/23	2023/24	2024/25	2025/26
Contracted TEC (GW)	92.70	102.04	116.08	140.63	151.71
Modelled TEC (GW)	86.68	89.48	95.78	108.91	113.82
Chargeable TEC (GW)	76.94	79.24	84.61	96.13	100.29

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 onwards as stated in the interconnector register as of July 2020.

⁹ See the Registers, Reports and Updates section at <https://www.nationalgrideso.com/connections/after-you-have-connected>

Table 25 Interconnectors

Interconnector	Node	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Aquind Interconnector	LOVE40	25		2,000	2,000	2,000	2,000
Auchencrosh (interconnector CCT)	AUCH20	10	490	990	990	990	990
Britned	GRAI40	24	1,200	1,200	1,200	1,200	1,200
Cronos	KEMS40	24					1,400
East West Interconnector	CONQ40	16	505	505	505	505	505
ElecLink	SELL40	24	1,000	1,000	1,000	1,000	1,000
EuroLink	LEIS40	18				1,600	1,600
FAB Link Interconnector	EXET40	26					1,400
Greenlink	PEMB40	20		504	504	504	504
Gridlink Interconnector	KINO40	24				1,500	1,500
IFA Interconnector	SELL40	24	2,000	2,000	2,000	2,000	2,000
IFA2 Interconnector	CHIL40	26	1,100	1,100	1,100	1,100	1,100
MARES	BODE40	16					750
Nemo Link	RICH40	24	2,040	2,040	2,040	2,040	2,040
NeuConnect Interconnector	GRAI40	24			1,400	1,400	1,400
NorthConnect	PEHE40	2				1,400	1,400
NS Link	BLYT4A	13	1,400	1,400	1,400	1,400	1,400
Viking Link Denmark Interconnector	BICF4A	17		1,500	1,500	1,500	1,500

14. Expansion Constant

The Expansion Constant (EC) is the annuitised value of the cost required to transport 1 MW over 1 km. It is required to be reset at the start of each price control and then inflated with RPI through the price control period.

Through the forecasting process, we have noticed a discrepancy between the STCP and the CUSC. This relates to the data that we obtain from the TO's and the methodology defined in the CUSC to calculate the Expansion Constant and Factors. The current STCP only permits the ESO to request from the TOs the information on projects that have occurred in the past 10 years whilst the CUSC defines that we should use more forward looking costs/data to calculate the Expansion Constant and Factors. We have raised this issue to the STC Panel and are working with the TOs to develop a proposal for a potential STCP change.

Based on the very limited historical data received so far from some of the TOs, the EC would be close to £27/MWkm for 2021/22. However, we don't believe that this value is correct nor suitable to feed into tariff calculations as it may create disproportionate tariffs, sending misleading signal to the industry. As such, we have used the current EC inflated by RPI for this five-Year view. They are listed in the table below.

Table 26 Expansion Constant

£/MWkm		2021/22	2022/23	2023/24	2024/25	2025/26
Expansion Constant		15.132042	15.501702	15.966882	16.445888	16.929926
	2009/10	2021/22	2022/23	2023/24	2024/25	2025/26
Base Revenue Inflation indices	1	1.399000	1.423000	1.459000	1.503000	1.549000

15. Locational onshore security factor

The locational onshore security factor (also called the global security factor), currently at 1.8, is applied to locational tariffs, and approximately represent the redundant network capacity to secure energy flows under network contingencies. This parameter is reviewed at the start of each price control period, and will be fixed for the RIIO-2 duration.

We have recalculated this figure based on the approach as described in CUSC 14.15.88, and the preliminary result is about 1.75, thus rounded to the existing value of 1.8. We will publish the detailed calculation assumption on our guidance webpage.

16. Onshore substation

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

For this five-year view, onshore substation tariffs are based on the values set for RIIO-1 inflated by RPI. We are working with the TO's to gather the relevant data to re-calculate the tariffs for the RIIO-2 period and would provide an update in the next forecast.

17. Offshore local tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant OFTO. These tariffs 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.

18. Allowed revenues

The majority of the TNUoS charges is to recover the allowed revenue for the onshore and offshore TOs in Great Britain. It also recovers some other revenue for example, Network Innovation Competition. The total amount recovered is adjusted for interconnector revenue recovery or redistribution.

In this report, the allowed revenues have been based on TOs forecast of their RIIO-T2 revenue, and their forecasts were based on RIIO-1 parameters including rate of return and inflation index. The 2021/22 revenue figures will be updated by November Draft tariffs, and finalised by January 2021 in the Final tariffs.

In addition, the implementation of CMP306 (align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital) may lead to one-off reduction to the allowed revenue figure for year 2021/22. The exact amount will be advised by the relevant TOs later this year. A preliminary analysis done by the CMP306 workgroup suggested the one-off adjustment would be up to £20m.

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

Table 27 Allowed revenues

Allowed Revenues					
£m Nominal	2021/22	2022/23	2023/24	2024/25	2025/26
National Grid Electricity Transmission					
Price controlled revenue	1,753.7	1,806.3	1,860.5	1,916.4	1,986.7
Less income from connections	29.8	29.8	29.8	29.8	29.8
Income from TNUoS	1,723.9	1,776.5	1,830.7	1,886.5	1,956.9
Scottish Power Transmission					
Price controlled revenue	384.2	395.5	405.3	430.1	443.0
Less income from connections	12.7	13.1	13.5	13.9	14.3
Income from TNUoS	371.5	382.3	391.8	416.2	428.6
SHE Transmission					
Price controlled revenue	383.4	392.4	406.7	421.2	421.2
Less income from connections	3.4	3.4	3.4	3.4	3.4
Income from TNUoS	380.0	389.0	403.3	417.8	417.8
National Grid Electricity System Operator					
Pass-through from TNUoS	17.5	17.6	17.7	17.8	17.8
Offshore (+ Interconnector cap&floor)	555.8	593.5	695.2	802.3	937.0
Total to Collect from TNUoS	3,048.6	3,158.8	3,338.6	3,540.6	3,758.1

Please note these figures are rounded to one decimal place.

19. Generation / Demand (G/D) Split

The revenue to be collected from generators and demand suppliers for 2021/22 will be updated throughout quarterly tariff forecasts, and will be finalised in the Final Tariffs.

The G/D split forecast is shown in Table 29. In this forecast, we assume CMP317/327 is implemented, and have built in the proposed methodology changes in the G/D split forecast. This forecast is subject to further potential methodology changes and an alternative option (instead of the original CUSC mod proposal option) may be chosen to be taken forward.

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 20.8% is also applied to reflect revenue and output forecasting accuracy. This revenue limit figure is normally referred to as the “EU gen cap”.

CMP317/327 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 £826.4m in 2021/22, an increase of £5.8m compared to March forecast. This figure is expected to rise to £1.2bn by 2025/26, mainly driven by increased offshore local charges.

Exchange Rate

As prescribed by the TNUoS charging methodology, the exchange rate for 2021/22 was taken from the Economic and Fiscal March Outlook, published by the Office of Budgetary Responsibility. The value is €1.210793/£ for 2021/22. Future years' forecast, from the same source, are listed in Table 29.

Generation Output

The forecast output of generation has been updated following the latest FES (Future Energy scenarios) publication. This figure is the average of the five scenarios (four FES scenarios, plus FES five-year forecast) in 2020 Future Energy Scenarios. For year 2021/22 tariff forecast, the generation output figure has now been locked down.

Error Margin

The error margin has been updated at 20.8%, following outturn of 2019/20 data.

Table 28 shows the error margin calculation, based on the last five full years' generation revenue and generation TWh output variance figures.

Table 28 Error Margin Calculation

Calculation for 2021/22			
Data from year:	Revenue inputs		Generation output variance
	Revenue variance	Adjusted variance	
2015/16	-8.7%	-0.1%	-12.2%
2016/17	-5.1%	3.5%	-7.9%
2017/18	-5.2%	3.4%	-1.5%
2018/19	-9.2%	-0.6%	-7.5%
2019/20	-14.6%	-6.1%	-4.1%
Systemic error:	-8.6%		
Adjusted error:		6.1%	12.2%
Error margin =			20.8%
Adjusted variance = the revenue variance - systemic error Systemic error = the average of all the values in the series Adjusted error = the average of the values in the series			

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

Table 29 Generation and demand revenue proportions

		2021/22	2022/23	2023/24	2024/25	2025/26
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
y	Error Margin	20.8%	20.8%	20.8%	20.8%	20.8%
ER	Exchange Rate (€/£)	1.21	1.20	1.18	1.17	1.17
MAR	Total Revenue (£m)	3048.6	3158.8	3338.6	3540.6	3758.1
GO	Generation Output (TWh)	222.8	210.0	206.5	207.9	214.0
G	% of revenue from generation	27%	28%	28%	30%	32%
D	% of revenue from demand	73%	72%	72%	70%	68%
G.MAR	Revenue recovered from generation (£m)	826.4	884.6	937.2	1056.2	1199.8
D.MAR	Revenue recovered from demand (£m)	2222.2	2274.2	2401.4	2484.3	2558.3

20. Charging bases for 2021/22- 2025/26

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.

Based on our best view and the Future Energy Scenarios, the generation charging base is forecast 76.9GW for 2021/22 and increase up to 100GW by 2025/26 ([see table 23](#)).

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated to follow forecasted out-turn for 2021/22 and for the subsequent 4 years (up to 2025/26). 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 2020)
- 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. The impact of COVID-19 on demand will begin to factor our forecast and modelling when the data becomes available.

Table 30 Demand charging bases

	2021/22	2022/23	2023/24	2024/25	2025/26
Average System Demand at Triad (GW)	50.16	50.60	50.37	50.07	50.30
Average HH Metered Demand at Triad (GW)	18.87	18.97	19.64	19.61	19.49
Chargeable Export Volume (GW)	7.31	6.66	6.39	6.64	6.18
NHH Annual Energy between 4pm and 7pm (TWh)	24.43	24.57	23.87	23.64	23.90

21. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 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.¹⁰

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

22. Generation and demand residuals

Under the existing CUSC methodology, 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

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

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)

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

Ofgem decided on 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 is managed

¹⁰<https://www.nationalgrideso.com/document/157476/download>

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.

The workgroup has not been concluded yet, so for the purpose of this document we have assumed a negative adjustment is still required to ensure compliance with the EU cap, this is referred to as the residual in this report. It has also been assumed that all local onshore and local offshore tariffs are not included in the EU cap, so removing these from Z_G .

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

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

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 AGIC¹¹ and phased residual.

Under the TDR, Ofgem also decided on some changes to the demand residual tariffs, i.e. the existing demand non-locational tariff will be replaced with a new set of £/site charges on final demand users, based on site banding.

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

Demand customers will continue paying the locational elements of demand tariffs, based on their triad demand for HH demand or their aggregated annual consumption during 4-7pm each day for their NHH demand. Under the CUSC modification proposal CMP343, options are being considered as to whether to “floor” the demand locational tariffs to zero in areas where the demand locational tariffs are negative. In this report, we assumed the “floored” option, and negative HH and NHH demand locational tariffs are floored at zero.

¹¹ Avoided Grid Supply Point Infrastructure Credit

Table 31 Residual components calculation

	Component	2021/22	2022/23	2023/24	2024/25	2025/26
G	Proportion of revenue recovered from generation (%)	12.0%	11.0%	10.4%	9.9%	9.6%
D	Proportion of revenue recovered from demand (%)	72.9%	72.0%	71.9%	70.2%	68.1%
R	Total TNUoS revenue (£m)	3048.6	3158.8	3338.6	3540.6	3758.1
Generation Residual						
R_G	Generator residual tariff (£/kW)	-6.24	-7.68	-8.59	-10.38	-11.61
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	382.3	418.8	481.1	645.5	689.6
O	Revenue recovered from offshore local tariffs (£m)	426.9	497.3	552.6	645.5	750.6
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.6	20.6	21.0	24.4	26.0
S_G	Revenue recovered from onshore local circuit tariffs (£m)	15.6	19.1	17.7	34.2	60.9
B_G	Generator charging base (GW)	76.9	79.2	84.6	96.1	100.3
Gross Demand Residual						
R_D	Demand residual tariff (£/kW)	46.55	47.13	50.10	52.28	53.62
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-99.2	-110.5	-122.1	-133.2	-138.9
EE	Amount to be paid to Embedded Export Tariffs (£m)	13.6	13.6	13.4	14.0	14.5
B_D	Demand Gross charging base (GW)	50.2	50.6	50.4	50.1	50.3



5

Sensitivity Analysis

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 the 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 2021/22-2025/26 tariffs include -

1. A scenario where the TGR (CMP317/327) changes are implemented over three years.
2. A scenario where congestion management costs are considered when setting the TNUoS tariffs to comply with the EU Gen Cap.
3. A scenario where a different inflation index is applied for the onshore TOs' revenue
4. A scenario where generators are grouped into 14 zones (by DNO's areas).
5. A scenario where generators are grouped into 48 zones (approximate scenario if we use the existing $\pm£1/\text{kW}$ zoning criteria).
6. A scenario where Small Generator Discount was extended to 2021/22.
7. A scenario where the remote Scottish isles become part of the wider network.

Caveats

The charging years 2021/22 – 2025/26 are in RIIO-T2 price control period, and a few TNUoS parameters are yet to be reset and finalised. 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 several 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.

23. Transmission Generator Residual Sensitivities

Phased TGR Implementation

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

Ofgem decided on the removal of the generation residual, which is currently used to keep total TNUoS recovery from generators within the range of $\text{€}0\text{-}2.50/\text{MWh}$. This change is 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.

For the purpose of this document, in our base case we have assumed a negative adjustment is still required to ensure compliance with the EU cap, this is referred to as the residual in this report. It has also been assumed that all local onshore and local offshore tariffs are not included in the EU cap.

The workgroup has not been concluded yet and one of the options being considered is a phased implementation to remove the generation residual over three years by including a $\text{£}/\text{kW}$ Transition Allowance Tariff (TAT) in addition to the negative generation residual as below:

- For charging year 2021/22: $\text{-£}3.71/\text{kW}$
- For charging year 2022/23: $\text{-£}1.85/\text{kW}$
- For all subsequent charging years: $\text{£}0/\text{kW}$

The table below shows the effect on TNUoS tariffs of including the TAT in addition to the negative residual calculated in the base case, which is shown in the main body of this report. Please note

that due to the implementation of the TDR in 2022/23 we are unable to show the impact of the average HH and NHH tariffs.

Table S1 The effect of phased implementation of TGR

		2021/22	2022/23	2023/24	2024/25	2025/26
Generation Residual	£/kW	- 3.942751	- 2.749494	- 1.598413	- 3.052436	- 3.263235
	Change	- 3.710000	- 1.850000	-	-	-
Average Generation Tariff*	£/kW	7.030461	9.281187	11.077140	10.986968	11.962772
	Change	- 3.710000	- 1.881594	-	-	-
Average HH demand tariff	£/kW	50.504205				
	Change	5.691477				
Average NHH demand tariff	p/kWh	6.419032				
	Change	0.728839				
Average EET tariff	£/kW	1.859122	2.035501	2.102387	2.102971	2.350862
	Change	-	-	-	-	-
Revenue from Generation	£m	540.95	735.47	937.21	1,056.20	1,199.79
	Change	- 285.46	- 149.10	-	-	-
Revenue from Demand	£m	2,507.64	2,423.35	2,401.43	2,484.35	2,558.27
	Change	285.46	149.10	-	-	-

*N.B These generation tariffs include local tariffs

The above table shows that with phased implementation generation would pay £285m less in 2021/22 and £149m less in 2022/23 compared to full implementation in 2021/22, reducing the generation residual and the average generation tariff. This revenue is added to the demand revenue, increase the average HH and NHH demand tariffs due to the increase in the demand residual. The EET is not impacted.

Inclusion of Congestion Management Costs

Whilst reviewing European legislation with regards with what is included in the report, it was found the definition is changing for ancillary services, which is excluded from the cap. It was found that the definition of ancillary services excludes congestion management costs, suggesting these costs should be included in the generation EU cap. Congestion management costs are currently paid through Balancing Services Use of System (BSUoS) charges.

We are aware that there is ongoing discussion as part of the CMP317/327 workgroup regarding the definition of congestion management costs and whether it should be included in the calculation for the generator charges EU cap. To help the industry to understand the implications of including congestion management cost in the TNUoS charges, we have provided a sensitivity analysis for 2021/22 illustrating its impact.

Based on the workgroup discussion around the definition and using the published Balancing Services Use of System (BSUoS) charge forecast¹², for this sensitivity we have assumed that congestion management costs include the following, which are estimated to total £463.7m for 2021/22.

- Energy imbalance
- Constraints – E&W
- Constraints – Cheviot
- Constraints – Scotland
- Constraints – Ancillary Services (AS)

¹² <https://data.nationalgrideso.com/balancing/bsuos-monthly-forecast>

Please note that the definition of congestion management costs has not been agreed and may be subject to change.

Table S2 The effect of including congestion management

		2021/22 Base Case	2021/22 Congestion Management Sensitivity	Change
Generation Residual	£/kW	- 0.232751	- 6.258778	- 6.026026
Average Generation Tariff*	£/kW	10.740461	4.714435	- 6.026026
Average HH demand tariff	£/kW	44.812728	54.057199	9.244471
Demand Residual	£/kW	46.554085	55.798556	9.244471
Average NHH demand tariff	p/kWh	5.690194	6.874021	1.183828
Average EET tariff	£/kW	1.859122	1.859122	-
Revenue from Generation	£m	826.40	362.74	- 463.661378
Revenue from Demand	£m	2,222.18	2,685.84	463.661378

*N.B These generation tariffs include local tariffs

The table above shows that the inclusion of the assumed congestion management costs would significantly decrease the amount of revenue collected from generation, a reduction of £463.7m. This would decrease the generation residual from £-0.23/kW to £-6.25/kW. This in turn increases the amount of revenue to be collected from demand users which increases the demand residual by £9.24/kW. The EET is not impacted.

24. Onshore TOs revenue sensitivity

Under the SO-TO Code (STC), we receive revenue forecast from the TOs, and combine TO's revenue with a few other miscellaneous pass-through items (e.g. Network Innovation Competition fund, interconnectors cap & floor adjustments), to work out the TNUoS revenue forecast.

Each OFTO has its own licence conditions which set out the allowed revenue stream, and the framework normally remain unchanged for typically 20 or 25 years.

For onshore TOs, their allowed revenue framework would be reviewed periodically via the price control process. The RIIO-2 price control period for onshore TOs is 2021/22 – 2025/26, and the final determination on the price control parameters will be published by Ofgem in December this year. For this report, the revenue forecast is based on TOs submission earlier this year, and the onshore TOs have used RIIO-1 financial parameters in their revenue calculation.

To illustrate the potential impacts from RIIO-2 financial parameters, we have undertaken a sensitivity where the onshore TOs' Base Revenue (BR) is inflated by CPIH instead of RPI, as proposed in the Ofgem's RIIO-T2 Draft Determination.

Under this sensitivity, the revenue figure would be lower by up to £107m (by 2025/26) compared to the values with RPI. But as we do not have adequate information to undertake the rate of return sensitivity, we did not alter the allowed rate of return for onshore TOs, which as suggested in Ofgem's DD, would also be lower than that in RIIO-T1,

The table below shows the reduction to revenue under the CPIH sensitivity, and the impact on TNUoS tariffs (TDR tariffs only)

Table S3 The effect of TO base revenue inflation by CPIH (as opposed to RPI)

Base Case		2021/22	2022/23	2023/24	2024/25	2025/26
Total TNUoS Revenue	£m	3,048.6	3,158.8	3,338.6	3,540.6	3,758.1
where Onshore TOs' Base Revenue (inflation index-linked)	£m	2,422.9	2,526.9	2,610.8	2,704.1	2,785.4
Inflation Index Assumption						
RPIf forecast (base year 2009/10)		1.399	1.423	1.459	1.503	1.549
RPIf year on year (re-base from 2021/22)			1.72%	2.53%	3.02%	3.06%
CPIH year on year (re-base from 2021/22)			0.72%	1.53%	2.02%	2.06%
CPIH forecast (re-base from 2021/22 RPIf)		1.399	1.409	1.431	1.459	1.489
CPIH Sensitivity						
Onshore TO Base Revenue linked to CPIH	£m	2,422.9	2,502.1	2,559.9	2,625.6	2,678.4
Reduction to the revenue from Base Case	£m	n/a	24.8	50.9	78.4	107.0
Reduction to TDR tariffs						
Domestic reduction	£/Site		0.32	0.66	1.02	1.38
LV_NoMIC_1 reduction	£/Site		0.15	0.32	0.49	0.68
LV_NoMIC_2 reduction	£/Site		0.79	1.63	2.51	3.42
LV_NoMIC_3 reduction	£/Site		1.86	3.82	5.88	8.01
LV_NoMIC_4 reduction	£/Site		5.55	11.37	17.53	23.92
LV1 reduction	£/Site		11.53	23.65	36.45	49.72
LV2 reduction	£/Site		19.21	39.37	60.70	82.80
LV3 reduction	£/Site		29.84	61.16	94.29	128.61
LV4 reduction	£/Site		67.08	137.51	211.98	289.15
HV1 reduction	£/Site		48.04	98.49	151.83	207.11
HV2 reduction	£/Site		166.35	341.03	525.73	717.13
HV3 reduction	£/Site		323.62	663.43	1,022.76	1,395.10
HV4 reduction	£/Site		797.27	1,634.37	2,519.57	3,436.85
EHV1 reduction	£/Site		279.91	573.81	884.59	1,206.63
EHV2 reduction	£/Site		1,672.86	3,429.33	5,286.72	7,211.41
EHV3 reduction	£/Site		3,566.07	7,310.35	11,269.76	15,372.62
EHV4 reduction	£/Site		9,589.78	19,658.81	30,306.34	41,339.66
T-Demand1 reduction	£/Site		1,454.61	2,981.91	4,596.97	6,270.54
T-Demand2 reduction	£/Site		5,163.92	10,585.91	16,319.42	22,260.67
T-Demand3 reduction	£/Site		10,158.51	20,824.71	32,103.72	43,791.38
T-Demand4 reduction	£/Site		30,620.57	62,771.44	96,769.48	131,999.36
Unmetered demand (p/kWh)						
Unmetered reduction	p/kWh		0.01	0.02	0.03	0.04

25. 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 final decision on financial parameters (e.g. rate of return, asset depreciation) will feed into TNUoS tariffs via the Expansion Constant (EC) / Expansion Factors (EFs) 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 the network 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, i.e. 14 generation zones in total;
- 2) To group generators that are within the same $\pm£1/\text{kW}$ nodal price range, into one zone. In our March forecast, we undertook this assessment which gave us 48 generation zones, and published the generator nodes to zones mapping¹³. In this report, we used the same mapping, and derived the indicative zonal tariffs under 48 generation zones.

¹³ <https://www.nationalgrideso.com/document/167311/download>

Table S4 Indicative generation wider tariffs under option 1 (14 zones) for 2021/22

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Gen Zone (Sensitivity)	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	Northern Scotland	3.702670	17.198452	16.137980	-0.139237	30.232578	33.460174	22.878123
2	Southern Scotland	3.068363	11.725641	9.569646	-0.139237	19.965355	21.879284	14.120664
3	Northern	3.610116	6.934381	3.135932	-0.139237	11.527129	12.154315	5.770447
4	North West	2.523208	4.796191	0.660405	-0.139237	6.749247	6.881328	2.439644
5	Yorkshire	4.046460	2.138685	0.043164	-0.139237	5.652702	5.661335	0.759401
6	N Wales & Mersey	3.807137	0.113387	0.000000	-0.139237	3.758609	3.758609	-0.093883
7	East Midlands	3.366833	-0.228741	0.000000	-0.139237	3.044603	3.044603	-0.230734
8	Midlands	2.344208	-4.155185	0.000000	-0.139237	-1.119177	-1.119177	-1.801311
9	Eastern	-1.148604	1.728907	0.000000	-0.139237	0.095285	0.095285	0.552325
10	South Wales	7.434049	-0.228741	-4.751205	-0.139237	3.310855	2.360614	-4.981938
11	South East	-4.606003	3.870421	0.000000	-0.139237	-1.648904	-1.648904	1.408931
12	London	-2.949541	-0.228741	-0.468143	-0.139237	-3.646286	-3.739914	-0.698876
13	Southern	-1.690669	-2.553012	0.000000	-0.139237	-3.872316	-3.872316	-1.160442
14	South Western	0.737476	-5.113731	0.000000	-0.139237	-3.492746	-3.492746	-2.184730

A list of sites, along with the generation zones they are mapped to under both options, was published as part of the March forecast excel tables.

In order to derive the boundary sharing factors (which split year round tariffs into year round shared and not-shared tariffs), zonal connectivity has been assessed, and the connectivity map is shown in Figure 8.

Figure 8 Generation zone connectivity map under 14-zone option

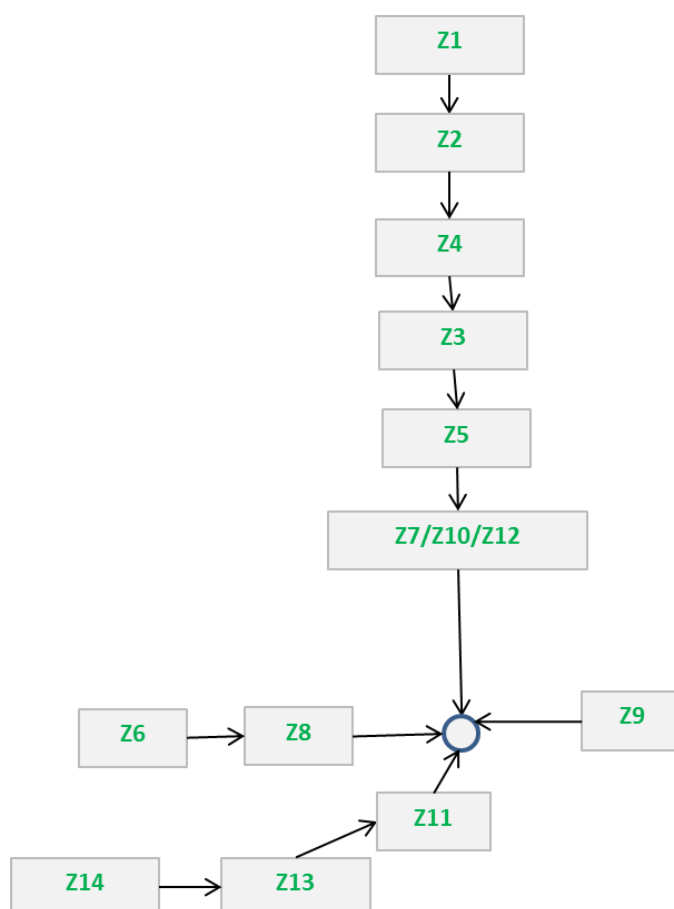


Table S5 Generation wider tariffs under 14 generation zones (2025/26 tariffs)

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Gen Zone (Sensitivity)	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	Northern Scotland	3.722012	15.644512	26.013757	-2.716637	34.331989	39.534741	29.554924
2	Southern Scotland	3.553599	9.451560	14.363203	-2.716637	19.888772	22.761412	15.427190
3	Northern	3.764109	6.945104	4.640494	-2.716637	10.315951	11.244050	4.701899
4	North West	2.338991	5.934674	3.151510	-2.716637	6.891300	7.521602	2.808742
5	Yorkshire	4.813232	2.479794	0.240926	-2.716637	4.273171	4.321356	-1.483794
6	N Wales & Mersey	2.675095	3.219354	0.000000	-2.716637	2.533941	2.533941	-1.428896
7	East Midlands	3.343078	1.720474	0.000000	-2.716637	2.002820	2.002820	-2.028448
8	Midlands	2.201635	-3.159323	0.000000	-2.716637	-3.042461	-3.042461	-3.980367
9	Eastern	-1.482477	3.156683	0.710228	-2.716637	-1.105585	-0.963540	-0.743736
10	South Wales	7.224291	1.720474	-7.534314	-2.716637	-0.143419	-1.650281	-9.562761
11	South East	-4.248353	3.717292	0.000000	-2.716637	-3.991156	-3.991156	-1.229721
12	London	-3.565958	1.720474	-3.483694	-2.716637	-7.693172	-8.389910	-5.512142
13	Southern	-1.410564	-3.281648	0.000000	-2.716637	-6.752520	-6.752520	-4.029297
14	South Western	0.368596	-6.096064	0.000000	-2.716637	-7.224892	-7.224892	-5.155063

Table S6 Generation wider tariffs under 48 generation zones (2021/22 tariffs)

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional Carbon 80% Load Factor (£/kW)	Conventional Low Carbon 80% Load Factor (£/kW)	Intermittent 40% Load Factor (£/kW)
Gen Zone (Sensitivity)	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)			
1	Zone 1	3.453949	16.023343	47.596230	0.000000	55.301299	64.820545	54.957258
2	Zone 2	1.666866	16.023343	13.821971	0.000000	26.494809	29.259203	21.183000
3	Zone 3	3.754486	16.023343	41.039376	0.000000	50.356352	58.564228	48.400405
4	Zone 4	-2.534198	24.466591	12.495561	0.000000	27.987215	30.486327	23.233888
5	Zone 5	3.302341	16.153658	13.821971	0.000000	28.234536	30.998930	21.235125
6	Zone 6	4.093634	24.049580	14.420878	0.000000	35.821691	38.705867	24.992401
7	Zone 7	4.197987	24.466591	14.466342	0.000000	36.296025	39.189293	25.204670
8	Zone 8	1.780010	20.044145	13.821971	0.000000	29.824594	32.588988	22.791320
9	Zone 9	4.378223	24.798942	14.546533	0.000000	36.806295	39.715602	25.417802
10	Zone 10	2.378456	16.377872	11.752194	0.000000	25.834200	28.184639	19.255034
11	Zone 11	4.520116	16.377872	15.075723	0.000000	30.634682	33.649827	22.578563
12	Zone 12	4.365612	19.269289	14.089768	0.000000	32.004550	34.822503	22.749175
13	Zone 13	4.103723	17.493424	12.579371	0.000000	29.113649	31.629524	20.528431
14	Zone 14	3.847798	17.035831	12.177814	0.000000	28.170405	30.605968	19.943838
15	Zone 15	3.495382	22.591964	15.010652	0.000000	34.529167	37.531297	24.999129
16	Zone 16	2.689152	12.167710	12.177814	0.000000	23.117262	25.552825	17.996589
17	Zone 17	3.051995	14.459122	10.739874	0.000000	24.162882	26.310857	17.475214
18	Zone 18	2.417404	13.331048	10.270643	0.000000	22.250448	24.304576	16.554753
19	Zone 19	2.640099	13.936724	10.552648	0.000000	23.183288	25.293818	17.079029
20	Zone 20	2.950624	9.641421	8.074403	0.000000	18.074975	19.689855	12.882662
21	Zone 21	2.810165	10.095897	8.534949	0.000000	18.666533	20.373523	13.524999
22	Zone 22	2.458474	11.773063	10.305692	0.000000	21.073169	23.134308	15.966609
23	Zone 23	2.406169	8.096024	6.288092	0.000000	14.865153	16.122772	10.478193
24	Zone 24	2.129143	7.194956	5.328174	0.000000	13.099339	14.164974	9.157848
25	Zone 25	3.340269	11.910792	0.000000	0.000000	13.820594	13.820594	5.716008
26	Zone 26	3.746953	5.187767	3.147705	0.000000	11.367023	11.996564	6.174503
27	Zone 27	2.523661	6.896323	0.000000	0.000000	8.992410	8.992410	3.710221
28	Zone 28	4.109303	2.215734	0.000000	0.000000	6.833581	6.833581	1.837985
29	Zone 29	3.385476	0.263788	0.000000	0.000000	4.548198	4.548198	1.057206
30	Zone 30	2.027682	0.475674	0.000000	0.000000	3.359912	3.359912	1.141961
31	Zone 31	5.341524	-0.019083	0.000000	0.000000	6.277949	6.277949	0.944058
32	Zone 32	3.454155	-2.287733	0.000000	0.000000	2.575659	2.575659	0.036598
33	Zone 33	2.275993	-3.306590	0.000000	0.000000	0.582413	0.582413	-0.370945
34	Zone 34	0.320683	1.557598	0.000000	0.000000	2.518453	2.518453	1.574730
35	Zone 35	-1.621055	1.479813	0.000000	0.000000	0.514487	0.514487	1.543617
36	Zone 36	9.620800	-4.990935	0.000000	0.000000	6.579744	6.579744	-1.044683
37	Zone 37	-4.303495	-2.145766	0.000000	0.000000	-5.068417	-5.068417	0.093385
38	Zone 38	-1.818412	0.166452	0.000000	0.000000	-0.733559	-0.733559	1.018272
39	Zone 39	-4.741778	4.819837	0.000000	0.000000	0.065782	0.065782	2.879626
40	Zone 40	-4.777454	3.113251	0.000000	0.000000	-1.335162	-1.335162	2.196991
41	Zone 41	-4.443633	4.369996	0.000000	0.000000	0.004055	0.004055	2.699690
42	Zone 42	-3.360975	-2.229923	0.000000	0.000000	-4.193222	-4.193222	0.059722
43	Zone 43	-0.360040	-3.798350	0.000000	0.000000	-2.447029	-2.447029	-0.567649
44	Zone 44	-3.934827	-0.072664	0.000000	0.000000	-3.041267	-3.041267	0.922625
45	Zone 45	-1.967715	-3.181280	0.000000	0.000000	-3.561048	-3.561048	-0.320821
46	Zone 46	-0.426135	-5.821013	0.000000	0.000000	-4.131254	-4.131254	-1.376714
47	Zone 47	2.658519	-5.142814	0.000000	0.000000	-0.504041	-0.504041	-1.105434
48	Zone 48	6.144564	-5.110799	0.000000	0.000000	3.007616	3.007616	-1.092628

26. Remote island sensitivity

There is a scenario that Grid Supply Points (GSPs) would be built on remote islands, at the remote end of long island links (for example, Orkney link, Shetland link and Western Isles link). In this sensitivity, we have assessed the indicative tariffs under this scenario, where the remote island links would become part of the wider network (and thus affect wider tariffs) due to the definition of MITS node under the CUSC.

Following approval of CMP320 (Island MITS radial link security factor) and CMP337/338 (impact of DNO contributions on actual project costs and expansion factors), we have incorporated CMP337/338 in this five year view, and CMP320 in this sensitivity.

Under this sensitivity, we have calculated two sets of generation wider tariffs for year 2025/26. In the first set of tariffs, remote island links are wider circuits and are part of generation zone 1. In the second set of tariffs, three new generation zones are created for the three remote island areas.

Table S7 Generation zone 1 tariffs - Remote island links in the wider network (2025/26 model)

Example tariffs for a generator of each technology type:								
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	3.095193	24.100185	34.613541	-3.367858	46.662020	53.584728	40.849461
2	East Aberdeenshire	3.576290	1.070859	34.224279	-3.367858	28.444542	35.289398	31.284765
3	Western Highlands	3.264373	17.423949	25.140861	-3.367858	33.948363	38.976535	28.742583
4	Skye and Lochalsh	3.347292	17.423949	31.660782	-3.367858	39.247219	45.579375	35.262504
5	Eastern Grampian and Tayside	6.303349	13.652762	21.459311	-3.367858	31.025149	35.317012	23.552558
6	Central Grampian	5.335746	13.721666	21.560925	-3.367858	30.193961	34.506146	23.681733
7	Argyll	5.236788	11.936661	35.231194	-3.367858	39.603214	46.649453	36.638000
8	The Trossachs	4.313075	11.936661	18.901484	-3.367858	25.615733	29.396030	20.308290
9	Stirlingshire and Fife	3.186898	10.780429	17.494382	-3.367858	22.438889	25.937765	18.438696
10	South West Scotlands	3.273522	10.864709	17.590400	-3.367858	22.669751	26.187831	18.568426
11	Lothian and Borders	3.530029	10.864709	10.342300	-3.367858	17.127778	19.196238	11.320326
12	Solway and Cheviot	2.888139	7.848860	10.427309	-3.367858	14.141216	16.226678	10.198995
13	North East England	3.739236	5.965286	5.676046	-3.367858	9.684444	10.819653	4.694302
14	North Lancashire and The Lakes	2.581054	5.965286	3.162757	-3.367858	6.515630	7.148182	2.181013
15	South Lancashire, Yorkshire and Humber	4.768576	2.669567	0.081877	-3.367858	3.601873	3.618249	-2.218154
16	North Midlands and North Wales	3.390470	2.431865	-0.042042	-3.367858	1.934470	1.926062	-2.437154
17	South Lincolnshire and North Norfolk	0.210896	2.519700	-0.037918	-3.367858	-1.171536	-1.179120	-2.397896
18	Mid Wales and The Midlands	1.074678	3.231942	-0.027836	-3.367858	0.270105	0.264538	-2.102917
19	Anglesey and Snowdon	3.394760	3.913773	-0.042042	-3.367858	3.124287	3.115878	-1.844391
20	Pembrokeshire	9.550242	-5.610873		-3.367858	1.693686	1.693686	-5.612207
21	South Wales & Gloucester	5.452625	-6.066025		-3.367858	-2.768053	-2.768053	-5.794268
22	Cotswold	2.659088	3.852996	-10.168283	-3.367858	-5.761000	-7.794656	-11.994943
23	Central London	-5.874151	3.852996	-1.847942	-3.367858	-7.637966	-8.007554	-3.674602
24	Essex and Kent	-3.526557	3.852996		-3.367858	-3.812018	-3.812018	-1.826660
25	Oxfordshire, Surrey and Sussex	-0.945766	-2.651696		-3.367858	-6.434981	-6.434981	-4.428536
26	Somerset and Wessex	-1.987839	-4.375050		-3.367858	-8.855737	-8.855737	-5.117878
27	West Devon and Cornwall	-1.171085	-8.479833		-3.367858	-11.322809	-11.322809	-6.759791

Table S8 Indicative wider tariffs for the three remote islands generation zones (2025/26 model)

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
0_1	Orkney	2.822946	18.790392	104.651511	-2.982535	98.593933	119.524235	109.185132
0_2	Shetland	1.836392	18.790392	80.679698	-2.982535	78.429929	94.565868	85.213320
0_3	Western Isles	3.136614	18.790392	102.471173	-2.982535	97.163330	117.657565	107.004795
1	North Scotland	3.095193	18.790392	27.041569	-2.982535	36.778226	42.186540	31.575190
2	East Aberdeenshire	3.576290	8.253569	27.041569	-2.982535	28.829865	34.238179	27.360461
3	Western Highlands	3.264373	17.423949	25.140861	-2.982535	34.333685	39.361858	29.127905
4	Skye and Lochalsh	3.347292	17.423949	31.660782	-2.982535	39.632542	45.964698	35.647826
5	Eastern Grampian and Tayside	6.303349	13.652762	21.459311	-2.982535	31.410472	35.702334	23.937881
6	Central Grampian	5.335746	13.721666	21.560925	-2.982535	30.579284	34.891469	24.067057
7	Argyll	5.236788	11.936661	35.231194	-2.982535	39.988537	47.034776	37.023324
8	The Trossachs	4.313075	11.936661	18.901484	-2.982535	26.001056	29.781353	20.693614
9	Stirlingshire and Fife	3.186898	10.780429	17.494382	-2.982535	22.824212	26.323088	18.824019
10	South West Scotlands	3.273522	10.864709	17.590400	-2.982535	23.055074	26.573154	18.953749
11	Lothian and Borders	3.530029	10.864709	10.342300	-2.982535	17.513101	19.581561	11.705648
12	Solway and Cheviot	2.888139	7.848860	10.427309	-2.982535	14.526539	16.612000	10.584317
13	North East England	3.739236	5.965286	5.676046	-2.982535	10.069767	11.204976	5.079626
14	North Lancashire and The Lakes	2.581054	5.965286	3.162757	-2.982535	6.900953	7.533504	2.566336
15	South Lancashire, Yorkshire and Humber	4.768576	2.669567	0.081877	-2.982535	3.987196	4.003571	-1.832831
16	North Midlands and North Wales	3.390470	2.431865	-0.042042	-2.982535	2.319793	2.311384	-2.051831
17	South Lincolnshire and North Norfolk	0.210896	2.519700	-0.037918	-2.982535	-0.786214	-0.793797	-2.012573
18	Mid Wales and The Midlands	1.074678	3.231942	-0.027836	-2.982535	0.655428	0.649860	-1.717595
19	Anglesey and Snowdon	3.394760	3.913773	-0.042042	-2.982535	3.509610	3.501201	-1.459068
20	Pembrokeshire	9.550242	-5.610873		-2.982535	2.079009	2.079009	-5.226884
21	South Wales & Gloucester	5.452625	-6.066025		-2.982535	-2.382730	-2.382730	-5.408945
22	Cotswold	2.659088	3.852996	-10.168283	-2.982535	-5.375676	-7.409333	-11.609619
23	Central London	-5.874151	3.852996	-1.847942	-2.982535	-7.252642	-7.622231	-3.289278
24	Essex and Kent	-3.526557	3.852996		-2.982535	-3.426695	-3.426695	-1.441337
25	Oxfordshire, Surrey and Sussex	-0.945766	-2.651696		-2.982535	-6.049658	-6.049658	-4.043214
26	Somerset and Wessex	-1.987839	-4.375050		-2.982535	-8.470415	-8.470415	-4.732555
27	West Devon and Cornwall	-1.171085	-8.479833		-2.982535	-10.937487	-10.937487	-6.374469

27. Small Generator Discount sensitivity

The Small Generator Discount (SGD) 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.

In the [March report](#) we forecasted what the SGD might be and the impact on demand tariffs if the discount was extended to 2021/22. Please view the March report for more details.



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 5-year view, please contact us using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

Charging webinars

We will be hosting a webinar for the five-year review on Wednesday 23rd September 2020. We will send out a communication to provide details on the webinar. For any questions please see our contact details below.

Charging model copies available

If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website 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

The ESO sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting at different locations and to recover the total allowed revenues of the onshore and offshore transmission owners.

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

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

The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and demand tariffs. The residual 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.

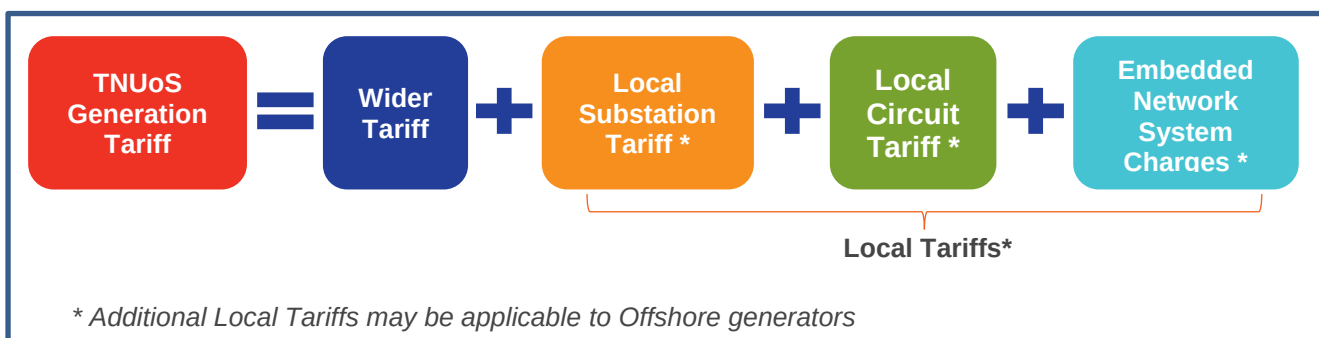
Generation charging principles

Transmission connected generators (and embedded generators with TEC $\geq 100\text{MW}$) are subject to the generation TNUoS charges.

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

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

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



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

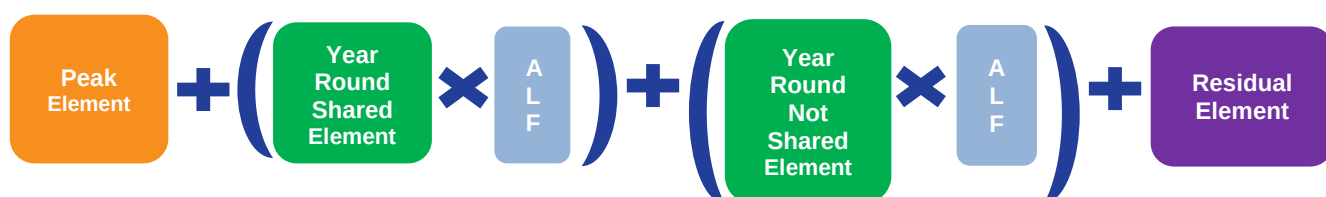
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

The Wider tariff

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

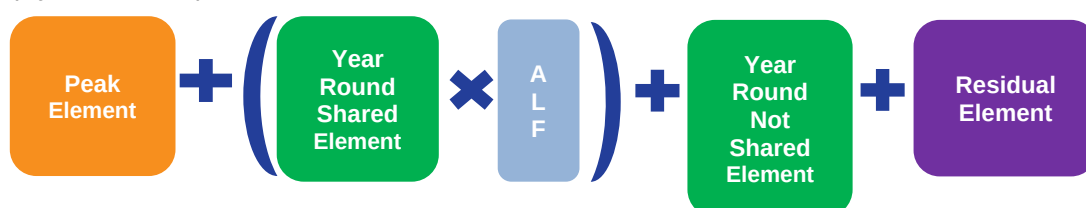
Conventional Carbon Generators

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



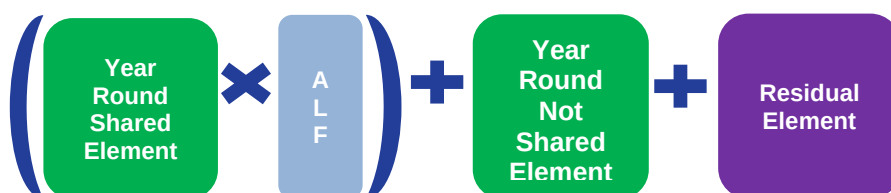
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

The ALFs used in these tariffs are listed from page 71.

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 residual charge is also used to ensure generator charges are compliant with European legislation, which requires total TNUoS recovery from generators to be within the range of €0-

2.50/MWh on average. For this report it has been assumed all local onshore tariffs (circuit and substation) and Offshore tariffs are excluded from the €2.50/MWh cap. Please note the code modification CMP317/327 has not been approved yet so this methodology may change. It is also expected that there will still be a requirement for a negative adjustment as part of the outcome for CMP317/327 when the TGR is set to £0/kW. For the purposes of this report we have referred to the negative adjustment as the residual for consistency.

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 BEGA¹⁴ if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS¹⁵ 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:

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

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.

¹⁴ Bilateral Embedded Generation Agreement. For more information about connections, please visit our website: <https://www.nationalgrid.com/uk/electricity/connections/applying-connection>

¹⁵ Distribution network Use of System charges

Generators with negative TNUoS tariffs

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

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

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

Demand charging principles

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

HH gross demand tariffs

HH gross demand tariffs are made up of locational and residual charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.¹⁶ 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 website¹⁷.

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 website¹⁸.

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.

¹⁶ <https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges/triads-data>

¹⁷ <https://www.nationalgrideso.com/document/130641/download>

¹⁸ <https://www.nationalgrideso.com/charging/charging-guidance>

NHH demand tariffs

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

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

TCR changes on Transmission Demand Residual (TDR) tariffs

For 2021/22, the current calculation methodology for demand tariffs remains the same. As of 2022/23, through the implementation of TDR, there will be changes to the demand tariffs i.e. the existing non-locational element in demand tariffs (the demand residual) will be replaced with a new set of £/site/year non-locational demand tariffs. The demand residual tariffs will be based on banding and applied to final demand. Final demand is the consumption used for purposes other than to operate a generating station, or to store and export. The methodology for demand locational tariffs would continue as it, however flooring on negative locational tariffs is being considered and assessed by the CMP343 workgroup.

I



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 – 2025/26. 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.

Table 32 Summary of in flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
<u>CMP280</u>	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
<u>CMP306</u>	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	Approved and will adjust 21/22 revenue.
<u>CMP316</u>	TNUoS Arrangements for Co-located Generation Sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types	to be confirmed
<u>CMP317 & CMP327</u>	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
<u>CMP324 & CMP325</u>	Generation Re-zoning	Revise TNUoS generation zoning methodology	April 2021, if approved
<u>CMP330</u>	Allowing new Transmission Connected parties to build Connection Assets greater than 2km in length	Change CUSC section 14 to enable connection assets greater than 2km in length	TBC
<u>CMP331</u>	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	TBC
<u>CMP334</u>	Transmission Demand Residual – consequential definition changes (TCR)	Replacing TNUoS demand residual tariff with fixed	April 2022, if approved

<u>CMP335/6</u>	CMP335: Transmission Demand Residual - Billing and consequential changes to CUSC Section 3 and 11 (TCR)' & CMP336 'Transmission Demand Residual - Billing and consequential changes to CUSC Section 14 (TCR)	p/site/day charge for final demand users	
<u>CMP340/343</u>	Transmission Demand Residual bandings and allocation for 1 April 2022 implementation (TCR)		
<u>CMP344</u>	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.	April 2021, if approved

We have not included the CUSC mods which may have a small or localised impact on the TNUoS charge in our forecast or in the above list.



C

Appendix C: Breakdown of locational HH and EE tariffs

Locational components of demand tariffs

The following tables show the components of the gross HH demand charge. The locational elements (peak security and year round) and residual. From 2022/23 the residual has been removed from the locational demand breakdown as per the impact of TDR (CMP343).

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

Table 33 Elements of the demand location tariff for 2021/22

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-2.284098	-27.168018	52.178588
2	Southern Scotland	-2.296205	-18.997821	52.178588
3	Northern	-3.486690	-7.369902	52.178588
4	North West	-1.557224	-2.800693	52.178588
5	Yorkshire	-2.400153	-0.934389	52.178588
6	N Wales & Mersey	-2.719694	-0.392999	52.178588
7	East Midlands	-2.219788	2.340331	52.178588
8	Midlands	-2.085716	3.210308	52.178588
9	Eastern	1.582745	0.687722	52.178588
10	South Wales	-6.391328	4.628439	52.178588
11	South East	4.322971	0.364750	52.178588
12	London	6.194452	1.924072	52.178588
13	Southern	1.944826	4.172059	52.178588
14	South Western	-0.997360	5.350683	52.178588

Table 34 Elements of the demand location tariff for 2022/23

Zone	Zone Name	Gross Half-Hourly Demand	
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)
1	Northern Scotland	-3.244375	-29.574718
2	Southern Scotland	-3.063705	-20.711837
3	Northern	-3.479816	-8.166870
4	North West	-1.969669	-3.846877
5	Yorkshire	-2.717769	-1.894985
6	N Wales & Mersey	-3.134699	-1.573485
7	East Midlands	-2.324357	1.775280
8	Midlands	-2.516972	2.717060
9	Eastern	1.921238	0.233915
10	South Wales	-6.849947	4.251570
11	South East	4.188384	0.307204
12	London	6.252706	1.560732
13	Southern	1.826993	3.856832
14	South Western	-1.197243	5.008742

Table 35 Elements of the demand location tariff for 2023/24

Zone	Zone Name	Gross Half-Hourly Demand	
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)
1	Northern Scotland	-3.089812	-29.856821
2	Southern Scotland	-3.198521	-20.880399
3	Northern	-3.958760	-8.101157
4	North West	-1.790805	-3.448129
5	Yorkshire	-3.385677	-1.577703
6	N Wales & Mersey	-2.866654	-0.994455
7	East Midlands	-2.503720	2.279024
8	Midlands	-2.103183	3.013047
9	Eastern	1.570958	0.517478
10	South Wales	-5.779460	5.677275
11	South East	4.517471	0.176265
12	London	6.642990	1.888350
13	Southern	2.119717	4.373732
14	South Western	-0.343869	6.189173

Table 36 Elements of the demand location tariff for 2024/25

Zone	Zone Name	Gross Half-Hourly Demand	
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)
1	Northern Scotland	-1.881896	-34.304403
2	Southern Scotland	-2.126992	-25.419466
3	Northern	-3.115240	-9.863410
4	North West	-0.938504	-4.046835
5	Yorkshire	-2.721129	-2.218991
6	N Wales & Mersey	-1.348915	-1.345812
7	East Midlands	-2.314642	2.152231
8	Midlands	-1.275688	2.870586
9	Eastern	0.581904	1.142231
10	South Wales	-5.288137	6.632581
11	South East	3.741160	0.662147
12	London	5.655827	2.693404
13	Southern	1.581334	4.708654
14	South Western	-1.295754	4.757286

Table 37 Elements of the demand location tariff for 2025/26

Zone	Zone Name	Gross Half-Hourly Demand	
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)
1	Northern Scotland	-1.529777	-35.408341
2	Southern Scotland	-1.738227	-26.113666
3	Northern	-3.281247	-10.537684
4	North West	-1.117157	-4.381060
5	Yorkshire	-2.923124	-2.430793
6	N Wales & Mersey	-0.782029	-0.729634
7	East Midlands	-2.092416	1.965054
8	Midlands	-1.176530	3.192612
9	Eastern	0.780863	1.026032
10	South Wales	-5.953834	6.593990
11	South East	3.495939	1.139299
12	London	5.460860	3.287033
13	Southern	1.435088	5.216113
14	South Western	-1.405748	5.339115

Table 38 shows the locational demand tariff elements used in the gross HH demand tariff and the EET, and the associated changes from the 2020/21 March Tariffs to the 2021/22 August Tariffs.

Table 38 Demand HH locational tariffs (2021/22 Forecast variation)

Demand Zone		2021/22 March		2021/22 August		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-1.755398	-30.047579	-1.559501	-29.948864	0.195897	0.098715
2	Southern Scotland	-2.660625	-21.332921	-2.564159	-21.500595	0.096466	-0.167673
3	Northern	-3.432121	-8.179343	-3.241022	-8.248344	0.191099	-0.069001
4	North West	-1.351652	-3.611617	-2.185331	-3.174417	-0.833679	0.437200
5	Yorkshire	-2.477629	-1.633776	-2.329010	-1.700130	0.148620	-0.066354
6	N Wales & Mersey	-2.205760	-0.478556	-2.476767	-0.782259	-0.271006	-0.303704
7	East Midlands	-2.321682	1.889024	-2.269741	1.927424	0.051940	0.038400
8	Midlands	-1.768773	2.894364	-2.160602	3.073794	-0.391829	0.179430
9	Eastern	1.447674	0.313126	1.375979	0.067569	-0.071695	-0.245557
10	South Wales	-6.473050	4.947334	-6.270157	4.990677	0.202893	0.043343
11	South East	3.872936	0.791247	4.133843	0.486328	0.260907	-0.304919
12	London	5.951036	1.678881	5.761676	0.939686	-0.189360	-0.739195
13	Southern	1.898214	4.104932	2.129560	3.947512	0.231346	-0.157420
14	South Western	-0.661798	5.832732	-0.409925	5.785214	0.251874	-0.047518

Table 39 shows the breakdown of the components that make up the EET.

Table 39 Breakdown of the EET (2021/22 Forecast variation)

Demand Zone		2021/22 March			2021/22 August			Changes		
		Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)
1	Northern Scotland	-31.802977	3.513565	-	-31.508365	2.287880	-	0.294612	-1.225685	-
2	Southern Scotland	-23.993547	3.513565	-	-24.064754	2.287880	-	-0.071207	-1.225685	-
3	Northern	-11.611464	3.513565	-	-11.489366	2.287880	-	0.122098	-1.225685	-
4	North West	-4.963269	3.513565	-	-5.359748	2.287880	-	-0.396479	-1.225685	-
5	Yorkshire	-4.111405	3.513565	-	-4.029140	2.287880	-	0.082265	-1.225685	-
6	N Wales & Mersey	-2.684316	3.513565	-	-3.259026	2.287880	-	-0.574710	-1.225685	-
7	East Midlands	-0.432658	3.513565	-	-0.342317	2.287880	-	0.090340	-1.225685	-
8	Midlands	1.125591	3.513565	-	0.913192	2.287880	-	-0.212399	-1.225685	-
9	Eastern	1.760799	3.513565	-	1.443548	2.287880	-	-0.317252	-1.225685	-
10	South Wales	-1.525717	3.513565	-	-1.279480	2.287880	-	0.246236	-1.225685	-
11	South East	4.664183	3.513565	-	4.620171	2.287880	-	-0.044013	-1.225685	-
12	London	7.629916	3.513565	-	6.701362	2.287880	-	-0.928555	-1.225685	-
13	Southern	6.003146	3.513565	-	6.077072	2.287880	-	0.073926	-1.225685	-
14	South Western	5.170934	3.513565	-	5.375290	2.287880	-	0.204356	-1.225685	-

The locational element is the sum of the peak and year round elements for the HH tariff in that zone (see Table 39 above).

The AGIC is the Avoided GSP Infrastructure Credit, which is indexed by average May to October RPI each year. The AGIC has been updated in this forecast as part of the RIIO-2 parameter reset.



D

Appendix D: Locational demand profiles

Locational demand profiles

Table 40 below shows the latest locational demand and demand charging base forecast used for the 2021/22 August forecast as well as the previous forecast (March).

The gross half-hourly (HH) demand forecast has decreased to 18.9GW and the non-half-hourly (NHH) demand forecast has increased to 24.4TWh. Embedded export volumes have also increased and are forecast to be 7.3GW.

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

Table 40 Demand profile (2021/22 Forecast Variation)

Zone	Zone Name	2021/22 March					2021/22 August				
		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	198	1,457	445	0.74	1,233	167	1,465	435	0.76	1,375
2	Southern Scotland	2,399	3,343	1,229	1.64	634	2,314	3,335	1,191	1.66	577
3	Northern	2,031	2,509	1,056	1.17	484	2,046	2,497	1,032	1.18	487
4	North West	2,869	3,927	1,501	1.91	368	2,881	3,931	1,470	1.95	441
5	Yorkshire	3,984	3,736	1,594	1.74	684	4,002	3,748	1,541	1.79	783
6	N Wales & Mersey	2,788	2,568	1,053	1.21	562	2,841	2,558	1,008	1.24	625
7	East Midlands	5,279	4,553	1,800	2.16	534	5,445	4,581	1,745	2.22	585
8	Midlands	4,433	4,140	1,598	1.97	228	4,445	4,155	1,560	2.01	268
9	Eastern	5,601	6,268	2,093	3.07	640	5,672	6,268	2,013	3.10	620
10	South Wales	1,604	1,775	815	0.83	368	1,642	1,778	799	0.84	419
11	South East	3,194	3,795	1,169	1.90	322	3,217	3,830	1,155	1.94	354
12	London	5,056	4,080	2,261	1.80	124	5,171	4,082	2,167	1.83	127
13	Southern	7,178	5,340	2,055	2.55	386	7,684	5,384	2,014	2.61	394
14	South Western	2,151	2,537	762	1.28	252	2,167	2,544	735	1.31	259
Total		48,765	50,028	19,431	23.97	6,820	49,694	50,156	18,866	24.43	7,313



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 three years 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 41 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

The data in Table 42 is taken from the TEC register from July 2020.

Please note that these values were not used for generation volumes in the best view models and were not used to derive the tariffs in this report, as they may be commercially sensitive.

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.

Table 42 Contracted generation TEC

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Aquind Interconnector	Interconnectors	LOVE40	25	0	2000	2000	2000	2000
Auchencrosh (interconnector CCT)	Interconnectors	AUCH20	10	490	990	990	990	990
Britned	Interconnectors	GRAI40	24	1200	1200	1200	1200	1200
Cronos	Interconnectors	KEMS40	24	0	0	0	0	1400
East West Interconnector	Interconnectors	CONQ40	16	505	505	505	505	505
ElecLink	Interconnectors	SELL40	24	1000	1000	1000	1000	1000
EuroLink	Interconnectors	LEIS40	18	0	0	0	1600	1600
FAB Link Interconnector	Interconnectors	EXET40	26	0	0	0	0	1400
Greenlink	Interconnectors	PEMB40	20	0	504	504	504	504
Gridlink Interconnector	Interconnectors	KINO40	24	0	0	0	1500	1500
IFA Interconnector	Interconnectors	SELL40	24	2000	2000	2000	2000	2000
IFA2 Interconnector	Interconnectors	CHIL40	26	1100	1100	1100	1100	1100
MARES	Interconnectors	BODE40	16	0	0	0	0	750
Nemo Link	Interconnectors	RICH40	24	2040	2040	2040	2040	2040
NeuConnect Interconnector	Interconnectors	GRAI40	24	0	0	1400	1400	1400
NorthConnect	Interconnectors	PEHE40	2	0	0	0	1400	1400
NS Link	Interconnectors	BLYT4A	13	1400	1400	1400	1400	1400
Viking Link Denmark Interconnector	Interconnectors	BICF4A	17	0	1500	1500	1500	1500
A'Chruach Wind Farm	Wind Onshore	ACHR1R	7	43	43	43	43	43
Aberarder Wind Farm	Wind Onshore	ABED10	1	49.99	49.99	49.99	49.99	49.99
Aberdeen Offshore Wind Farm	Wind Offshore	ABBA10	1	95.5	95.5	95.5	95.5	95.5
Abergelli Power Limited	OCGT	SWAN20_SPM	21	0	299	299	299	299
Aberthaw	Coal	ABTH20	21	1610	1610	1610	1610	1610
Aberthaw (Tertiary)	Wind Onshore	ABTH20	21	0	0	0	57	57

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Afton Wind Farm	Wind Onshore	BLAH10	10	50	50	50	50	50
Aigas (part of the Beaulieu Cascade)	Hydro	AIGA1Q	1	20	20	20	20	20
Aikengall Ila Wind Farm	Wind Onshore	WDOD10	11	81.2	81.2	81.2	81.2	81.2
Aikengall II Windfarm	Wind Onshore	WDOD10	11	63.8	63.8	63.8	63.8	63.8
Alverdiscott	Pump Storage	ALVE4A	27	0	0	49.9	49.9	49.9
An Suidhe Wind Farm, Argyll (SRO)	Wind Onshore	ANSU10	7	19.3	19.3	19.3	19.3	19.3
Arecleoch	Wind Onshore	AREC10	10	114	114	114	114	114
Arecleoch Windfarm Extension	Wind Onshore	AREC10	10	0	0	0	0	72.8
Axminster	Pump Storage	AXMI40_SEP	26	0	49.9	49.9	49.9	49.9
Axminster Tertiary	Pump Storage	AXMI40_SEP	26	0	49.9	49.9	49.9	49.9
Bad a Cheo Wind Farm	Wind Onshore	MYBS11	1	26.65	26.65	26.65	26.65	26.65
Baglan Bay	CCGT	BAGB20	21	552	593	593	593	593
Barrow Offshore Wind Farm	Wind Offshore	HEYS40	14	90	90	90	90	90
Beatrice Wind Farm	Wind Offshore	BLHI40	1	588	588	588	588	588
Beaw Field Wind Farm	Wind Onshore	BEWF10	1	0	0	0	72	72
Beinneun Wind Farm	Wind Onshore	BEIN10	3	109	109	109	109	109
Beinn Tharsuinn Extension	Wind Onshore	FYRI2J	1	0	0	0	44.8	44.8
Benbrack Wind Farm	Wind Onshore	KEOO10	10	0	0	72	72	72
Bhlaraidh Extension Wind Farm	Wind Onshore	BHLA10	3	0	0	0	100.8	100.8
Bhlaraidh Wind Farm	Wind Onshore	BHLA10	3	108	108	108	108	108
Blackcraig Wind Farm	Wind Onshore	BLCW10	10	52.9	52.9	52.9	52.9	52.9
Blacklaw	Wind Onshore	BLKL10	11	118	118	118	118	118
Blacklaw Extension	Wind Onshore	BLKX10	11	60	60	60	60	60
Bolney	Pump Storage	BOLN40	25	0	49.9	49.9	49.9	49.9
Bolney (tertiary)	Wind Onshore	BOLN40	25	0	0	0	57	57
Braintree	Pump Storage	BRAI4A	18	0	0	0	49.9	49.9
Braintree (Tertiary)	Wind Onshore	BRAI4A	18	0	0	0	0	49.9
Bramford (Tertiary PP)	Pump Storage	BRFO40	18	49.9	49.9	49.9	49.9	49.9
Bramford Tertiary	Wind Onshore	BRFO40	18	0	0	0	57	57
Bramley (tertiary)	Wind Onshore	BRLE40	25	0	0	0	57	57
Bredbury	Pump Storage	BRED20	16	0	49.9	49.9	49.9	49.9
Bridgwater (tertiary)	Wind Onshore	BRWA40	26	0	0	0	57	57
Broken Cross Windfarm	Wind Onshore	COAL10	11	0	0	48	48	48

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Burbo Bank Extension Offshore Wind Farm	Wind Offshore	BODE40	16	258	258	258	258	258
Burwell (Tertiary)	Pump Storage	BURW40	18	49.9	49.9	49.9	49.9	49.9
Bustleholme	Pump Storage	BUST20	18	49.9	49.9	49.9	49.9	49.9
Capenhurst Gas	CCGT	CAPE20	16	0	49.5	49.5	49.5	49.5
Carraig Gheal Wind Farm	Wind Onshore	FERO10	7	46	46	46	46	46
Carrington	Pump Storage	CARR20	16	0	49.9	49.9	49.9	49.9
Carrington Power Station	CCGT	CARR40	16	910	910	910	910	910
CDCL	CCGT	COTT40	16	445	445	445	445	445
Chirmorie Wind Farm	Wind Onshore	MAHI10	10	0	0	80	80	80
Clash Gour	Wind Onshore	CLGO20	1	0	0	0	210	210
Clashindarroch Extension	Wind Onshore	CAIN20	1	0	0	37.5	37.5	37.5
Clauchrie Windfarm	Wind Onshore	MAHI20	10	0	0	0	0	84
Cleve Hill Solar Park	Wind Onshore	CLEH40	24	0	350	350	350	350
Cloiche Wind Farm	Wind Onshore	MELG10	5	0	0	0	0	200
Clunie (part of the Clunie Cascade)	Hydro	CLUN1S	5	61.2	61.2	61.2	61.2	61.2
Clyde North	Wind Onshore	CLYN2Q	11	374.5	374.5	374.5	374.5	374.5
Clyde South	Wind Onshore	CLYS2R	11	128.8	128.8	128.8	128.8	128.8
Codling Park Wind Farm	Wind Offshore	PENT40	19	0	0	0	1000	1000
Coire Glas Pumped Storage	Pump Storage	COGL40	3	0	0	0	0	612
Connahs Quay	CCGT	CONQ40	16	1380	1380	1380	1380	1380
Coopers Lane Kirkby	CCGT	KIBY20	15	0	49.5	49.5	49.5	49.5
Corby	CCGT	GREN40_EME	18	401	401	401	401	401
Corriegarth	Wind Onshore	COGA10	1	69	69	69	69	69
Corriegarth 2 Wind Farm	Wind Onshore	COGA10	1	0	0	0	96	96
Corriemoillie Wind Farm	Wind Onshore	CORI10	1	47.5	47.5	47.5	47.5	47.5
Coryton	CCGT	COSO40	24	800	800	800	800	800
Costa Head Wind Farm	Wind Onshore	COST10	1	0	0	0	20.4	20.4
Cour Wind Farm	Wind Onshore	CRSS10	7	20.5	20.5	20.5	20.5	20.5
Coventry	Pump Storage	COVE20	18	49.9	49.9	49.9	49.9	49.9
Cowes	OCGT	FAWL40	26	140	140	140	140	140
Cowley	Pump Storage	COWL40	25	49.9	49.9	49.9	49.9	49.9
Cowley (Tertiary)	Wind Onshore	COWL40	25	0	0	0	57	57
CPG Power	CCGT	CARR40	16	0	49.9	49.9	49.9	49.9

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Creag Riabhach Wind Farm	Wind Onshore	CREA10	1	0	79.2	79.2	79.2	79.2
Crookedstane Windfarm	Wind Onshore	CLYS2R	11	25.4	25.4	25.4	25.4	25.4
Crossdykes	Wind Onshore	EWEH1Q	12	46	46	46	46	46
Crossdykes Extension	Wind Onshore	EWEH1Q	12	0	0	0	40	40
Cruachan	Pump Storage	CRUA20	8	440	440	440	440	440
Crystal Rig III Wind Farm	Wind Onshore	CRYR40	11	13.8	13.8	13.8	13.8	13.8
Crystal Rig II Wind Farm	Wind Onshore	CRYR40	11	138	138	138	138	138
Crystal Rig IV Wind Farm	Wind Onshore	CRYR40	11	0	48.2	48.2	48.2	48.2
Culligran (part of the Beaully Cascade)	Hydro	CULL1Q	1	19.1	19.1	19.1	19.1	19.1
Cumberhead	Wind Onshore	COAL10	11	0	50	50	50	50
Cumberhead West Wind Farm	Wind Onshore	COAL10	11	0	0	0	100	100
Dalquhandy Wind Farm	Wind Onshore	COAL10	11	0	45	45	45	45
Damhead Creek	CCGT	KINO40	24	812	812	812	812	812
Damhead Creek 2	CCGT	KINO40	24	1800	1800	1800	1800	1800
Deanie (part of the Beaully Cascade)	Hydro	DEAN1Q	1	38	38	38	38	38
Deeside Power Station	CCGT	CONQ40	16	1	1	1	1	1
Dersalloch Wind Farm	Wind Onshore	DERS1Q	10	69	69	69	69	69
Derwent	CHP	WILE40	18	162	162	162	162	162
Didcot B	CCGT	DIDC40	25	1450	1450	1450	1450	1450
Dinorwig	Pump Storage	DINO40	19	1644	1644	1644	1644	1644
Dogger Bank Project 1	Wind Offshore	CREB40	15	0	0	1200	1200	1200
Dogger Bank Project 2	Wind Offshore	CREB40	15	0	0	0	1500	1500
Dogger Bank Project 4	Wind Offshore	CREB40	15	0	0	1200	1200	1200
Dorenell Windfarm	Wind Onshore	DORE11	1	177	177	177	177	177
Douglas West	Wind Onshore	COAL10	11	45	45	45	45	45
Douglas West Extension	Wind Onshore	COAL10	11	0	0	0	60	60
Drakelow	Wind Onshore	DRAK40	18	0	0	0	57	57
Drax (Biomass)	Biomass	DRAX40	15	1905	1905	1905	1905	1905
Drax (CCGT)	CCGT	DRAX40	15	0	0	1190	1190	1190
Drax (Coal)	Coal	DRAX40	15	2001	2001	1936	1936	1936
Dudgeon Offshore Wind Farm	Wind Offshore	NECT40	17	400	400	400	400	400
Dungeness B	Nuclear	DUNG40	24	1120	1120	1120	1120	1120
Dunlaw Extension	Wind Onshore	DUNE10	11	29.75	29.75	29.75	29.75	29.75

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Dunmaglass Wind Farm	Wind Onshore	DUNM10	1	94	94	94	94	94
East Anglia 3	Wind Offshore	BRFO40	18	0	0	1200	1200	1200
East Anglia One	Wind Offshore	BRFO40	18	680	680	680	680	680
East Claydon	Wind Onshore	ECLA40_EME	18	0	0	0	0	500
Edinbane Wind, Skye	Wind Onshore	EDIN10	4	41.4	41.4	41.4	41.4	41.4
Eggborough	CCGT	EGGB40	15	0	0	0	2450	2450
Elchies Wind Farm	Wind Onshore	ELCH10	1	0	0	0	99	99
Elstree (tertiary)	Wind Onshore	ELST40	25	0	0	0	57	57
Energy Isles	Wind Offshore	ENEI10	1	0	0	0	120.3	120.3
Enfield	CCGT	BRIM2A_EPN	24	442	442	442	442	442
Enoch Hill	Wind Onshore	ENHI10	10	0	0	69	69	69
Equinor	Wind Offshore	NORM40	18	0	0	0	0	719
Errochty	Hydro	ERRO10	5	75	75	75	75	75
Ewe Hill	Wind Onshore	EWEH1Q	12	39	39	39	39	39
Exeter (Tertiary)	Pump Storage	EXET40	26	49.9	49.9	49.9	49.9	49.9
Fallago Rig 2	Wind Onshore	FALL40	11	41.4	41.4	41.4	41.4	41.4
Fallago Rig Wind Farm	Wind Onshore	FALL40	11	144	144	144	144	144
Farr Wind Farm, Tomatin	Wind Onshore	FAAR1Q	1	92	92	92	92	92
Fasnakyle G1 & G2	Hydro	FASN20	3	46	46	46	46	46
Fasque Windfarm	Wind Onshore	FASQ10	5	0	0	0	0	90
Fawley CHP	CHP	FAWL40	26	158	158	158	158	158
Faw Side Community Wind Farm	Wind Onshore	GRNA10	12	0	0	0	0	250
Feckenham	Pump Storage	FECK40	18	0	12	12	12	12
Ffestiniog	Pump Storage	FFES20	16	360	360	360	360	360
Finlarig	Hydro	FINL1Q	6	16.5	16.5	16.5	16.5	16.5
Firth of Forth Offshore Wind Farm 2A	Wind Offshore	BRNX40	11	0	0	700	700	700
Firth of Forth Offshore Wind Farm 2B	Wind Offshore	BRNX40	11	0	0	0	700	700
Firth of Forth Phase 1	Wind Offshore	TEAL20	5	1075	1075	1075	1075	1075
Fleet (Tertiary)	Wind Onshore	FLEE40	25	0	0	0	49.9	49.9
Foyers	Pump Storage	FOYE20	1	300	300	300	300	300
Freasdail	Wind Onshore	CRSS10	7	22.2	22.2	22.2	22.2	22.2
Galawhistle Wind Farm	Wind Onshore	GAWH10	11	55.2	55.2	55.2	55.2	55.2
Galloper Wind Farm	Wind Offshore	LEIS10	18	348	348	348	348	348

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Gateway Energy Centre Power Station	Pump Storage	COSO40	24	0	0	619.99	1000	1000
Glen App Windfarm	Wind Onshore	AREC10	10	32.2	32.2	32.2	32.2	32.2
Glendoe	Hydro	GLDO1G	3	99.9	99.9	99.9	99.9	99.9
Glen Kyllachy Wind Farm	Wind Onshore	GLKO10	1	48.5	48.5	48.5	48.5	48.5
Glenmoriston (part of the Moriston Cascade)	Hydro	GLEN1Q	3	40	40	40	40	40
Glenmuckloch Pumped Storage	Pump Storage	GLMU10	10	0	0	0	210	210
Glenmuckloch Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	33.6	33.6
Glenshero	Wind Onshore	GLSH10	5	0	0	0	168	168
Glenshimmeroch Windfarm	Wind Onshore	NECU10	10	0	0	48	48	48
Glen Ullinish Wind Farm	Wind Onshore	GLNU10	3	0	0	0	0	49.9
Gordonbush Wind Farm	Wind Onshore	GORW20	1	108	108	108	108	108
Grain	CCGT	GRAI40	24	1517	1517	1517	1517	1517
Grangemouth CHP	CHP	GRMO20	9	120	120	120	120	120
Greater Gabbard Offshore Wind Farm	Wind Offshore	LEIS10	18	500	500	500	500	500
Great Yarmouth	CCGT	NORM40	18	420	420	420	420	420
Griffin Wind Farm	Wind Onshore	GRIF1S	5	188.6	188.6	188.6	188.6	188.6
Gunfleet Sands II Offshore Wind Farm	Wind Offshore	BRFO40	18	64	64	64	64	64
Gunfleet Sands Offshore Wind Farm	Wind Offshore	BRFO40	18	99.9	99.9	99.9	99.9	99.9
Gwynt Y Mor Offshore Wind Farm	Wind Offshore	BODE40	16	574	574	574	574	574
Hadyard Hill	Wind Onshore	HADH10	10	99.9	99.9	99.9	99.9	99.9
Hagshaw Hill Phase 1	Wind Onshore	COAL10	11	0	0	0	30	30
Hagshaw Hill Phase 2	Wind Onshore	COAL10	11	0	0	0	54	54
Halsary Wind Farm	Wind Onshore	MYBS11	1	28.5	28.5	28.5	28.5	28.5
Harestanes	Wind Onshore	HARE10	12	163.3	163.3	163.3	163.3	163.3
Harker	Pump Storage	HARK40	12	0	0	0	49.9	49.9
Harting Rig Wind Farm	Wind Onshore	KYPE10	11	0	0	0	61.2	61.2
Hartlepool	Nuclear	HATL20	13	1207	1207	1207	1207	1207
Hesta Head Wind Farm	Wind Onshore	HEST10	1	0	0	0	20.4	20.4
Heysham Power Station	Nuclear	HEYS40	14	2388	2388	2388	2388	2388
Hinkley Point B	Nuclear	HINP40	26	1061	1061	1061	1061	1061
Hinkley Point C	Nuclear	HINP40	26	0	0	0	1670	3340
Hirwaun Power Station	OCGT	RHIG40	21	299	299	299	299	299
Hollandmey Windfarm	Wind Onshore	GILB10	1	0	0	0	0	49.5

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Holyhead	Biomass	WYLF40	19	150	150	150	150	150
Hopsrig Wind Farm	Wind Onshore	EWEH1Q	12	0	48	48	48	48
Hornsea Power Station 1A	Wind Offshore	KILL40	15	400	400	400	400	400
Hornsea Power Station 1B	Wind Offshore	KILL40	15	400	400	400	400	400
Hornsea Power Station 1C	Wind Offshore	KILL40	15	400	400	400	400	400
Hornsea Power Station 2A	Wind Offshore	KILL40	15	440	440	440	440	440
Hornsea Power Station 2B	Wind Offshore	KILL40	15	440	440	440	440	440
Hornsea Power Station 2C	Wind Offshore	KILL40	15	440	440	440	440	440
Hornsea Power Station 3A-1 (formerly 3A)	Wind Offshore	NORM40	18	0	0	500	500	500
Hornsea Power Station 3A-2 (formerly 3B)	Wind Offshore	NORM40	18	0	0	500	500	500
Hornsea Power Station 4	Wind Offshore	CREB40	15	0	0	0	0	1100
Hornsea Power Station Project 3B-1 (formerly 3C)	Wind Offshore	NORM40	18	0	0	0	500	500
Hornsea Power Station Project 3B-2 (formerly 3D)	Wind Offshore	NORM40	18	0	0	0	500	500
Humber Gateway Offshore Wind Farm	Wind Offshore	HEDO20	15	220	220	220	220	220
Hunterston	Nuclear	HUER40	10	1000	1000	1000	1000	1000
Hutton	Pump Storage	HUTT40	14	0	0	49.9	49.9	49.9
Immingham	CHP	HUMR40	15	1268	1268	1268	1268	1268
Inch Cape Offshore Wind Farm Platform 1	Wind Offshore	COCK20	11	0	0	1080	1080	1080
Inch Cape Offshore Wind Farm Platform 2	Wind Offshore	COCK20	11	0	0	1080	1080	1080
Indian Queens PP	OCGT	INDQ40	27	140	140	140	140	140
Indian Queens Battery	Pump Storage	INDQ40	27	0	0	49.9	49.9	49.9
Indian Queens	Pump Storage	INDQ40	27	0	0	49.9	49.9	49.9
Invergarry (part of the Garry Cascade)	Hydro	INGA1Q	3	20	20	20	20	20
Iron Acton	Wind Onshore	IROA10	18	120	120	120	120	120
Iver	Pump Storage	IVER4A	25	0	0	49.9	49.9	49.9
J G Pears	CHP	HIGM20	16	13	13	13	13	13
Keadby	CCGT	KEAD40	16	755	755	755	755	755
Keadby II	CCGT	KEAD40	16	893	893	893	893	893
Kearsley	Pump Storage	KEAR40	15	0	49.9	49.9	49.9	49.9
Keith Hill Wind Farm	Wind Onshore	DUNE10	11	4.5	4.5	4.5	4.5	4.5
Kemsley PP	Pump Storage	KEMS40	24	49.9	49.9	49.9	49.9	49.9
Kennoxhead Wind Farm	Wind Onshore	COAL10	11	0	0	112	112	112
Kennoxhead Wind Farm Extension	Wind Onshore	MIDM10	11	60	60	60	60	60

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Kestrel Meadow BCA	Pump Storage	BURW40	18	0	0	0	0	500
Kilbraur Wind Farm	Wind Onshore	STRB20	1	67	67	67	67	67
Kilgallioch	Wind Onshore	KILG20	10	228	274	274	274	274
Killingholme	OCGT	KILL40	15	600	600	600	600	600
Kilmorack (part of the Beaully Cascade)	Hydro	KIOR1Q	1	20	20	20	20	20
King's Lynn 'B' Power Station	CCGT	KINL49	17	0	0	0	1700	1700
Kings Lynn A	CCGT	WALP40_EME	17	380	380	380	380	380
Kirkby (Tertiary)	Pump Storage	KIBY20	15	49.9	49.9	49.9	49.9	49.9
Kype Muir	Wind Onshore	KYPE10	11	88.4	88.4	88.4	88.4	88.4
Laleham	Pump Storage	LALE20_SEP	25	0	49.9	49.9	49.9	49.9
Landulph	Pump Storage	LAND4A	27	0	49.9	49.9	49.9	49.9
Langage	CCGT	LAGA40	27	905	905	905	905	905
Lethans Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	132	132
Limekiln	Wind Onshore	LIMK10	1	0	84	84	84	84
Lincs Offshore Wind Farm	Wind Offshore	WALP40_EME	17	256	256	256	256	256
Lister Drive Battery	Pump Storage	LISD20	15	49.9	49.9	49.9	49.9	49.9
Lister Drive	Pump Storage	LISD20	15	0	0	50	50	50
Little Barford	CCGT	EASO40	18	740	740	740	740	740
Llanwern Phase 1	Wind Onshore	WHSO20	21	0	0	49.9	49.9	49.9
Llanwern Phase 2	Wind Onshore	WHSO20	21	0	0	190	190	190
Lochay (Part of Killin Cascade Hydro Scheme)	Hydro	LOCH10	6	47	47	47	47	47
Lochgoin Solar Farm	Wind Onshore	WLEE20	10	0	0	89	89	89
Lochluichart	Wind Onshore	CORI10	1	69	69	69	69	69
Loch Luichart Extension II	Wind Onshore	LUIC1Q	1	0	0	0	36	36
London Array Offshore Wind Farm	Wind Offshore	CLEH40	24	630	630	630	630	630
Lorg Wind Farm	Wind Onshore	KEOO10	10	0	0	0	49.5	49.5
Lovedean	Pump Storage	LOVE40	25	0	49.9	49.9	49.9	49.9
Lovedean (Tertiary)	Wind Onshore	LOVE40	25	0	0	0	57	57
Luichart (part of the Conon Cascade)	Hydro	LUIC1Q	1	34	34	34	34	34
Lynemouth Power Station	Biomass	BLYT20	13	396	396	396	396	396
Mannington	Pump Storage	MANN40	26	0	0	0	49.9	49.9
Mannington Tertiary	Pump Storage	MANN40	26	0	0	0	49.9	49.9
Marchwood	CCGT	MAWO40	26	920	920	920	920	920

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Mark Hill Wind Farm	Wind Onshore	MAHI20	10	53	53	53	53	53
Medway Power Station	CCGT	GRAI40	24	735	735	735	735	735
Melksham	Wind Onshore	MELK40_SEP	21	0	0	0	49.99	49.99
Melksham (Tertiary)	Wind Onshore	MELK40_SEP	21	0	0	0	57	57
Melksham 1 Tertiary	Pump Storage	MELK40_SEP	21	0	0	0	49.9	49.9
Melksham 2 Tertiary	Pump Storage	MELK40_SEP	21	0	0	0	49.9	49.9
MeyGen Tidal	Tidal	GILB10	1	0	0	0	71	154
Middle Muir Wind Farm	Wind Onshore	MIDM10	11	51	51	51	51	51
Milford Haven	Biomass	PEMB40	20	0	350	350	350	350
Millbrook Power	OCGT	MILB49	18	0	299	299	299	299
Millennium South	Wind Onshore	MILS1Q	3	25	25	25	25	25
Millennium Wind	Wind Onshore	MILW1Q	3	65	65	65	65	65
Minety Tertiary(2)	CCGT	MITY40	21	0	0	0	49.99	49.99
Minnygap	Wind Onshore	MOFF10	12	25	25	25	25	25
Monquhill Wind Farm	Wind Onshore	ENHI10	10	0	0	0	0	10
Moray East Offshore Wind Farm	Wind Offshore	NEDE20	2	900	900	900	900	900
Moray West Offshore Windfarm	Wind Offshore	BLHI40	1	0	0	0	800	800
Mossford (part of the Conon Cascade)	Hydro	MOSS1S	1	18.7	18.7	18.7	18.7	18.7
Mossy Hill Wind Farm	Wind Onshore	BLHI40	1	0	0	0	49.9	49.9
Muaitheabhal Wind Farm	Wind Onshore	MUAI10	1	0	0	0	0	150
Nant	Hydro	NANT1Q	7	15	15	15	15	15
Near Na Gaoithe Offshore Wind Farm	Wind Offshore	CRYR40	11	150	448	448	448	448
North Hyde	CCGT	NHYD20	25	0	0	49.5	49.5	49.5
North Killingholme Power Project	CCGT	KILL40	15	540	540	540	540	540
North Kyle New Cumnock	Wind Onshore	NECU10	10	0	0	0	212	212
North Lowther Energy Initiative	Wind Onshore	ELVA2Q	11	0	0	0	151.2	151.2
Norwich	CCGT	NORM40	18	0	49.5	49.5	49.5	49.5
Norwich Battery	Pump Storage	NORM40	18	0	0	0	49.9	49.9
Nursling Tertiary	Pump Storage	NURS40	26	49.9	49.9	49.9	49.9	49.9
Oldbury (Tertiary)	Pump Storage	OLDB4A	18	49.9	49.9	49.9	49.9	49.9
Ormonde Offshore Wind Farm	Wind Offshore	HEYS40	14	150	150	150	150	150
Orrin (part of the Conon Cascade)	Hydro	ORRI10	1	18	18	18	18	18
Osballdwick	Pump Storage	OSBA40	15	49.9	49.9	49.9	49.9	49.9

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Overhill Wind Farm	Wind Onshore	NECU10	10	0	0	48	48	48
Pembroke Power Station	CCGT	PEMB40	20	2199	2199	2199	2199	2199
Pencloe Windfarm	Wind Onshore	BLAH10	10	0	79.8	79.8	79.8	79.8
Pen Y Cymoedd Wind Farm	Wind Onshore	RHIG40	21	228	228	228	228	228
Peterborough	CCGT	WALP40_EPN	17	245	245	245	245	245
Peterhead	CCGT	PEHE20	2	1180	1180	1180	1180	1180
Pogbie Wind Farm	Wind Onshore	DUNE10	11	9.6	9.6	9.6	9.6	9.6
Porters Wood	Wind Onshore	PORW49	23	0	0	0	0	500
Port of Mostyn	Tidal	CONQ40	16	0	0	0	210	210
Powersite @ Drakelow	CCGT	DRAK40	18	380	380	380	380	380
Priestgill Wind Farm	Wind Onshore	ELVA40	11	0	41	41	41	41
Progress Power Station	OCGT	YAXL49	18	0	299	299	299	299
Race Bank Wind Farm	Wind Offshore	WALP40_EME	17	565	565	565	565	565
Rampion Offshore Wind Farm	Wind Offshore	BOLN40	25	400	400	400	400	400
Ratcliffe on Soar	Coal	RATS40	18	2021	2021	2021	2021	2021
Richborough 1	Pump Storage	RICH40	24	0	50	50	50	50
Richborough 2	Pump Storage	RICH40	24	0	50	50	50	50
Robin Rigg East Offshore Wind Farm	Wind Offshore	HARK40	12	86	86	86	86	86
Robin Rigg West Offshore Wind Farm	Wind Offshore	HARK40	12	92	92	92	92	92
Rochdale	Pump Storage	ROCH40	15	0	0	49.9	49.9	49.9
Rocksavage	CCGT	ROCK40	16	810	810	810	810	810
Rye House	CCGT	RYEH40	24	715	715	715	715	715
Sallachy Wind Farm	Wind Onshore	SALA10	1	0	0	0	50	50
Saltend	CCGT	SAES20	15	1100	1100	1100	1100	1100
Sandy Knowe Wind Farm	Wind Onshore	GLGL1Q	10	51	51	51	90	90
Sanquhar II Wind Farm	Wind Onshore	GLGL1Q	10	0	0	0	250	250
Sanquhar Wind Farm	Wind Onshore	GLGL1Q	10	30	30	30	30	30
Scoop Hill Wind Farm	Wind Onshore	MOFF10	12	0	0	0	0	500
Seabank	CCGT	SEAB40	22	1234	1234	1234	1234	1234
Seabank (Tertiary)	Pump Storage	SEAB40	22	49.9	49.9	49.9	49.9	49.9
Seagreen Project 1+	Wind Offshore	COCK20	11	0	0	360	360	360
Sellafeld	CHP	HUTT40	14	155	155	155	155	155
Sellindge (Tertiary)	Pump Storage	SELL40	24	49.9	49.9	49.9	49.9	49.9

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Severn Power	CCGT	USKM20	21	850	850	850	850	850
SHBEC	CCGT	SHBA40	15	0	83	83	83	83
Sheirdrim Wind Farm	Wind Onshore	CRSS10	7	0	0	0	84	84
Shepherds Rig Wind Farm	Wind Onshore	NECU10	10	0	0	0	84.6	84.6
Sheringham Shoal Offshore Wind Farm	Wind Offshore	NORM40	18	315	315	315	315	315
Shoreham	CCGT	BOLN40	25	420	420	420	420	420
Shrewsbury Solar	Wind Onshore	SHRE4A	18	0	0	0	49.99	49.99
Sizewell B	Nuclear	SIZE40	18	1230	1230	1230	1230	1230
Sloy G2 and G3	Hydro	SLOY10	8	80	80	80	80	80
Sofia Offshore Wind Farm	Wind Offshore	LACK40	13	0	0	600	1200	1200
South Humber Bank	CCGT	SHBA40	15	1365	1365	1365	1365	1365
South Kyle	Wind Onshore	NECU10	10	0	235	235	235	235
Spalding	CCGT	SPLN40	17	950	950	950	950	950
Spalding Energy Expansion	CCGT	SPLN40	17	850	850	850	850	850
Spennymoor	Pump Storage	SPEN4A	13	0	0	49.9	49.9	49.9
Staythorpe C	CCGT	STAY40	16	1752	1752	1752	1752	1752
St Dennis Hendra PV	Wind Onshore	INDQ40	27	0	0	0	0	49.9
Stornoway Wind Farm	Wind Onshore	STOR10	1	0	0	0	0	180
Stranoch Wind Farm	Wind Onshore	MAHI10	10	0	0	0	102	102
Strathy North and South Wind	Wind Onshore	STRW10	1	67.65	67.65	67.65	225.25	275.25
Strathy Wood	Wind Onshore	STRW10	1	0	0	0	54.4	54.4
Stronelairg	Wind Onshore	STRL10	5	227.8	227.8	227.8	227.8	227.8
Sundon	CCGT	SUND40	18	0	49.5	49.5	49.5	49.5
Sundon Pivoted Power	Pump Storage	SUND40	18	0	49.9	49.9	49.9	49.9
Sutton Bridge	CCGT	WALP40_EME	17	850	850	850	850	850
Swansea Bay	Tidal	BAGB20	21	0	0	320	320	320
Tangy III Wind Farm	Wind Onshore	CAAD1Q	7	0	0	39.1	39.1	39.1
Taunton	Pump Storage	TAUN4A	26	0	0	49.9	49.9	49.9
Taylors Lane	CCGT	WISD20_LPN	23	144	144	144	144	144
Tees CCGP	CCGT	GRSA20	13	0	0	0	850	850
Tees Renewable Energy Plant	Biomass	LACK20	13	285	285	285	285	285
Templeborough	CCGT	TEMP2A	16	0	0	49.5	49.5	49.5
Thanet Extension Offshore Wind Farm	Wind Offshore	RICH40	24	0	0	340	340	340

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Thanet Offshore Wind Farm	Wind Offshore	CANT40	24	300	300	300	300	300
Thurrock	CCGT	TILB20	24	0	0	300	750	750
Toddleburn Wind Farm	Wind Onshore	DUNE10	11	27.6	27.6	27.6	27.6	27.6
Torness	Nuclear	TORN40	11	1250	1250	1250	1250	1250
Tottenham	Pump Storage	TOTT20	24	0	49.9	49.9	49.9	49.9
Trafford Power	CCGT	CARR40	16	2050	2050	2050	2050	2050
Triton Knoll Offshore Wind Farm	Wind Offshore	BICF4A	17	900	900	900	900	900
Troston Wind Farm	Wind Onshore	NECU10	10	0	0	0	0	68
Twentysilling Wind Farm	Wind Onshore	GLGL1Q	10	37.8	37.8	37.8	37.8	37.8
Upware Solar Farm	Wind Onshore	BURW40	18	49.99	49.99	49.99	49.99	49.99
Uskmouth	Coal	USKM20	21	230	230	230	230	230
Vanguard	Wind Offshore	NECT40	17	0	0	0	1800	1800
Viking Wind Farm	Wind Onshore	KERG20	1	0	0	0	457	457
Walney 3 Offshore Wind Farm	Wind Offshore	MIDL40	14	330	330	330	330	330
Walney 4 Offshore Wind Farm	Wind Offshore	MIDL40	14	330	330	330	330	330
Walney II Offshore Wind Farm	Wind Offshore	STAH4A	14	182	182	182	182	182
Walney I Offshore Wind Farm	Wind Offshore	HEYS40	14	182	182	182	182	182
Walpole	Pump Storage	WALP40_EME	17	0	49.9	49.9	49.9	49.9
Walpole 1 (Tertiary)	Wind Onshore	WALP40_EME	17	0	0	0	57	57
Walpole 2 (tertiary)	Wind Onshore	WALP40_EME	17	0	0	0	57	57
Warley	CCGT	WARL20	18	0	49.5	49.5	49.5	49.5
Warley (tertiary)	Wind Onshore	WARL20	18	0	0	0	57	57
Waterbeach Solar Farm	Wind Onshore	BURW40	18	0	49.99	49.99	49.99	49.99
West Burton A	Coal	WBUR40	16	1975	1975	1975	1975	1975
West Burton B	CCGT	WBUR40	16	1333	1333	1333	1333	1333
Westermest Rough Offshore Wind Farm	Wind Offshore	HEDO20	15	206.5	206.5	206.5	206.5	206.5
West of Duddon Sands Offshore Wind Farm	Wind Offshore	HEYS40	14	382	382	382	382	382
West Weybridge	Pump Storage	WWEY20	25	0	0	49.9	49.9	49.9
Whitelaw Brae Windfarm	Wind Onshore	CLYS2R	11	0	57	57	57	57
Whitelee	Wind Onshore	WLEE20	10	305	305	305	305	305
Whitelee Extension	Wind Onshore	WLEX20	10	206	206	206	206	206
Whiteside Hill Wind Farm	Wind Onshore	GLGL1Q	10	27	27	27	27	27
Willington	OCGT	WILE40	18	1145	1973	1973	1973	1973

Generator	Technology	Nodes	Zone	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
Willington Battery	Pump Storage	WILE40	18	0	49.9	49.9	49.9	49.9
Wilton	CCGT	GRSA20	13	141	141	141	141	141
Windy Rig Wind Farm	Wind Onshore	BLAH10	10	42.8	42.8	42.8	42.8	42.8
Windy Standard II (Brockloch Rig) Wind Farm	Wind Onshore	DUNH1R	10	61.5	75	75	75	75
Windy Standard III Wind Farm	Wind Onshore	DUNH1Q	10	0	0	43.5	43.5	43.5
Worset Solar Park	Wind Onshore	HARM20	13	38	38	38	38	38
Wylfa Substation	Wind Onshore	WYLF40	19	0	0	0	120	120
Wymondley	Pump Storage	WYMO40	18	0	49.9	49.9	49.9	49.9

Table 43 Contracted TEC by generation zone

Zone	Zone Name	2021/22 (MW)	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)
1	North Scotland	2,096.1	2,259.3	2,296.8	4,655.6	5,168.1
2	East Aberdeenshire	2,080.0	2,080.0	2,080.0	3,480.0	3,480.0
3	Western Highlands	512.9	512.9	512.9	613.7	1,275.6
4	Skye and Lochalsh	41.4	41.4	41.4	41.4	41.4
5	Eastern Grampian and Tayside	1,627.6	1,627.6	1,627.6	1,795.6	2,085.6
6	Central Grampian	63.5	63.5	63.5	63.5	63.5
7	Argyll	166.0	166.0	205.1	289.1	289.1
8	The Trossachs	520.0	520.0	520.0	520.0	520.0
9	Stirlingshire and Fife	120.0	120.0	120.0	120.0	120.0
10	South West Scotland	2,950.1	3,824.4	4,273.9	5,386.6	5,621.4
11	Lothian and Borders	2,960.0	3,499.2	6,879.2	8,035.6	8,035.6
12	Solway and Cheviot	451.3	499.3	499.3	589.2	1,339.2
13	North East England	3,467.0	3,467.0	4,116.9	5,566.9	5,566.9
14	North Lancashire and The Lakes	4,189.0	4,189.0	4,238.9	4,238.9	4,238.9
15	South Lancashire, Yorkshire and Humber	11,875.2	12,057.6	15,682.5	19,632.5	20,732.5
16	North Midlands and North Wales	14,014.0	14,213.2	14,262.7	14,472.7	15,222.7
17	South Lincolnshire and North Norfolk	5,396.0	6,945.9	6,945.9	10,559.9	10,559.9
18	Mid Wales and The Midlands	8,925.4	10,711.6	12,911.6	15,832.4	17,601.3
19	Anglesey and Snowdon	1,794.0	1,794.0	1,794.0	2,914.0	2,914.0
20	Pembrokeshire	2,199.0	3,053.0	3,053.0	3,053.0	3,053.0
21	South Wales & Gloucester	3,769.0	4,109.0	4,668.9	4,982.7	4,982.7
22	Cotswold	1,283.9	1,283.9	1,283.9	1,283.9	1,283.9
23	Central London	144.0	144.0	144.0	144.0	644.0
24	Essex and Kent	15,210.8	15,710.7	18,370.7	20,700.7	22,100.7
25	Oxfordshire, Surrey and Sussex	2,319.9	4,469.6	4,618.9	4,953.8	4,953.8
26	Somerset and Wessex	3,478.8	3,578.6	3,628.5	5,455.3	8,525.3
27	West Devon and Cornwall	1,045.0	1,094.9	1,244.6	1,244.6	1,294.5



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Appendix G Transmission company revenues

Transmission Owner revenue forecasts

In this report, the revenue forecasts are based on figures submitted in February by all onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs. We have updated the RPI forecast, thus the figures have changed slightly from March forecast. The revenue forecast for 2021/22 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, interconnector revenue adjustments under cap & floor, and site-specific adjustments by TOs etc, and these figures would also be updated in November and January.

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

Notes:

All monies are quoted in millions of pounds, accurate to 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 in Table 44 below shows details of the pass-through TNUoS revenue items under NGESO's licence conditions. We have assumed the same pass-through items under NGESO's licence during RIIO-2.

Table 44 NGESO revenue breakdown

Term	NGESO TNUoS Other Pass-Through				
	2021/22	2022/23	2023/24	2024/25	2025/26
RPIft	1.399	1.423	1.459	1.503	1.549
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6	0.6	0.6
Network Innovation Competition (NICFt)	13.9	13.9	13.9	13.9	13.9
ESO Network Innovation Allowance (NIAft)	3.0	3.1	3.2	3.3	3.3
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	555.8	593.5	695.2	802.3	937.0
Financial facility (FINt)	-	-	-	-	-
Site Specific Charges Discrepancy (DISft)	-	-	-	-	-
Termination Sums (TSt)	-	-	-	-	-
NGET revenue pas-through (NGETTOt)*	1,723.9	1,776.5	1,830.7	1,886.5	1,956.9
SPT revenue pass-through (TSPTt)	371.5	382.3	391.8	416.2	428.6
SHE TL revenue pass-through (TSHTt)	380.0	389.0	403.3	417.8	417.8
Total	3,048.6	3,158.8	3,338.6	3,540.6	3,758.1

A few items (including FINt, DISft and TSt) are set to zero in the August forecast cycle for 2021/22. FINt was introduced as a "bridging" financial facility, following the legal separation of ESO from NGET, and will be reviewed for RIIO-2. DISft 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) provided preliminary revenue forecast for year 2021/22 – 2025/26 in February 2020, 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 £550.8m, an increase of £25.9m since to our March Forecast. This increase is driven by the inclusion of final revenues for sites that have asset transferred since March and also the availability of additional information used in forecasts for sites which have not yet asset transferred. Revenues have been adjusted to take into account an updated inflation forecast (as defined in the relevant OFTO licences).

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.

Typically, IFA's adjustment for these arrangements reduces the total TNUoS revenue. On its own IFA revenue contribution for 2021/22 would have reduced the TNUoS charges by £12.2m. However, for year 2021/22, the forecasted IFA interconnector adjustment, is a one-off payment to recover the Capacity Allocation and Congestion Management (CACM) pilot project costs¹⁹. This is a provisional adjustment subject to the required licence change being applied. Therefore, the indicative net impact is that the interconnector revenue forecast increases 2021/22 TNUoS revenue cost by around £5.1m.

¹⁹ <https://www.ofgem.gov.uk/ofgem-publications/155391>

Table 45 NGET revenue breakdown

Description			National Grid Electricity Transmission				
Regulatory Year		Licence Term	2021/22	2022/23	2023/24	2024/25	2025/26
RPIFt							
Base Revenue $[A=(A1+A2+A3)*A4]$	A	BRt	1688.8	1747.3	1799.7	1853.7	1922.2
Pass-Through Items $[B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]$	B	PTt	40.2	41.4	42.6	43.9	45.2
Outputs Incentive Revenue $[C=C1+C2+C3+C4]$	C	OIPt	17.2	17.7	18.2	18.8	19.3
Network Innovation Allowance	D	NIAt	7.6				
Network Innovation Competition	E	NICFt					
Transmission Investment for Renewable Generation	G	TIRGt					
TO Adjustments and Correction	H+I +K	DIST+TSt-Kt	0.0				
Financial Facilities	J	FINt					
Maximum Revenue $[M= A+B+C+D+E+F+G+H+I+K+J]$	M	TOt	1753.7	1806.3	1860.5	1916.4	1986.7
Pre-vesting connection charges	S1		29.7	29.7	29.7	29.7	29.7
Rental Site	S2		0.1	0.1	0.1	0.1	0.1
Post Vesting, Pre-BETTA connection charges	S						
TNUoS Collected Revenue onshore TO $[T=M-B5-S]$	T		1723.9	1776.5	1830.7	1886.5	1956.9

Table 46 SPT revenue breakdown

Description			Scottish Power Transmission				
Regulatory Year		Licence Term	2021/22	2022/23	2023/24	2024/25	2025/26
RPIFt							
Base Revenue $[A=(A1+A2+A3)*A4]$	A	BRt	351.6	388.2	405.3	430.1	443.0
Pass-Through Items $[B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]$	B	PTt	4.1	3.8	0.0	0.0	0.0
Outputs Incentive Revenue $[C=C1+C2+C3+C4]$	C	OIPt	3.4	3.5	0.0	0.0	0.0
Network Innovation Allowance	D	NIAt					
Network Innovation Competition	E	NICFt					
Transmission Investment for Renewable Generation	G	TIRGt	32.5	0.0	0.0	0.0	0.0
TO Adjustments and Correction	H+I +K	DIST+TSt-Kt	-7.4				
Financial Facilities	J	FINT					
Maximum Revenue $[M= A+B+C+D+E+F+G+H+I+K+J]$	M	TOt	384.2	395.5	405.3	430.1	443.0
Pre-vesting connection charges	S1						
Rental Site	S2						
Post Vesting, Pre-BETTA connection charges	S		12.7	13.1	13.5	13.9	14.3
TNUoS Collected Revenue onshore TO $[T=M-B5-S]$	T		371.5	382.3	391.8	416.2	428.6

Table 47 SHETL revenue breakdown

Description			SHE Transmission				
Regulatory Year		Licence Term	2021/22	2022/23	2023/24	2024/25	2025/26
RPIFt							
Base Revenue [A=(A1+A2+A3)*A4]	A	BRt	382.5	391.5	405.8	420.3	420.3
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	B	PTt	0.0	0.0	0.0	0.0	0.0
Outputs Incentive Revenue [C=C1+C2+C3+C4]	C	OIPt	0.0	0.0	0.0	0.0	0.0
Network Innovation Allowance	D	NIAt	0.9	0.9	0.9	0.9	0.9
Network Innovation Competition	E	NICFt					
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	0.0	0.0
TO Adjustments and Correction	H+I +K	DIST+TSt-Kt					
Financial Facilities	J	FINt					
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K+J]	M	TOt	383.4	392.4	406.7	421.2	421.2
Pre-vesting connection charges	S1						
Rental Site	S2						
Post Vesting, Pre-BETTA connection charges	S		3.4	3.4	3.4	3.4	3.4
TNUoS Collected Revenue onshore TO [T=M-B5-S]	T		380.0	389.0	403.3	417.8	417.8

Table 48 Offshore revenues

Offshore Transmission Revenue Forecast	18/08/2020					
Regulatory Year	2021/22	2022/23	2023/24	2024/25	2025/26	Notes
Barrow	6.7	6.9	7.1	7.3	7.5	Current revenues plus indexation
Gunfleet	8.4	8.6	8.8	9.1	9.4	Current revenues plus indexation
Walney 1	15.4	15.6	16.1	16.7	17.1	Current revenues plus indexation
Robin Rigg	9.4	9.7	9.9	10.2	10.5	Current revenues plus indexation
Walney 2	15.2	16.0	16.7	17.1	17.6	Current revenues plus indexation
Sheringham Shoal	23.4	23.9	24.5	25.3	26.0	Current revenues plus indexation
Ormonde	14.2	14.5	14.9	15.3	15.8	Current revenues plus indexation
Greater Gabbard	32.1	32.7	33.8	34.5	35.7	Current revenues plus indexation
London Array	44.5	45.7	47.0	48.4	49.8	Current revenues plus indexation
Thanet	20.8	21.3	22.0	22.6	23.3	Current revenues plus indexation
Lincs	30.2	30.9	31.8	32.7	33.6	Current revenues plus indexation
Gwynt y mor	30.6	31.4	32.4	33.3	34.3	Current revenues plus indexation
West of Duddon Sands	24.3	24.9	25.6	26.4	27.2	Current revenues plus indexation
Humber Gateway	13.0	13.3	13.7	14.1	14.5	Current revenues plus indexation
Westernmost Rough	14.1	14.5	14.9	15.3	15.8	Current revenues plus indexation
Burbo Bank	14.1	14.5	14.9	15.4	15.8	Current revenues plus indexation
Dudgeon	20.0	20.4	21.0	21.6	22.2	Current revenues plus indexation
Race Bank	27.8	28.5	29.3	30.2	31.1	Current revenues plus indexation
Galloper	17.1	17.5	18.1	18.6	19.2	Current revenues plus indexation
Walney 3	13.5	13.9	14.4	14.8	15.2	Current revenues plus indexation
Walney 4	13.5	13.9	14.4	14.8	15.2	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2020/21	103.7	106.3	109.5	112.8	116.1	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2021/22	38.7	77.6	79.9	82.3	84.8	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2022/23		39.2	92.2	92.9	95.7	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2023/24			0.0	0.0	0.0	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2024/25				99.9	159.7	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2025/26					53.1	National Grid ESO Forecast
Offshore Transmission Pass-Through (B7)	550.7	641.6	712.8	831.5	966.2	

Notes: Figures for historic years represent National Grid ESO'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

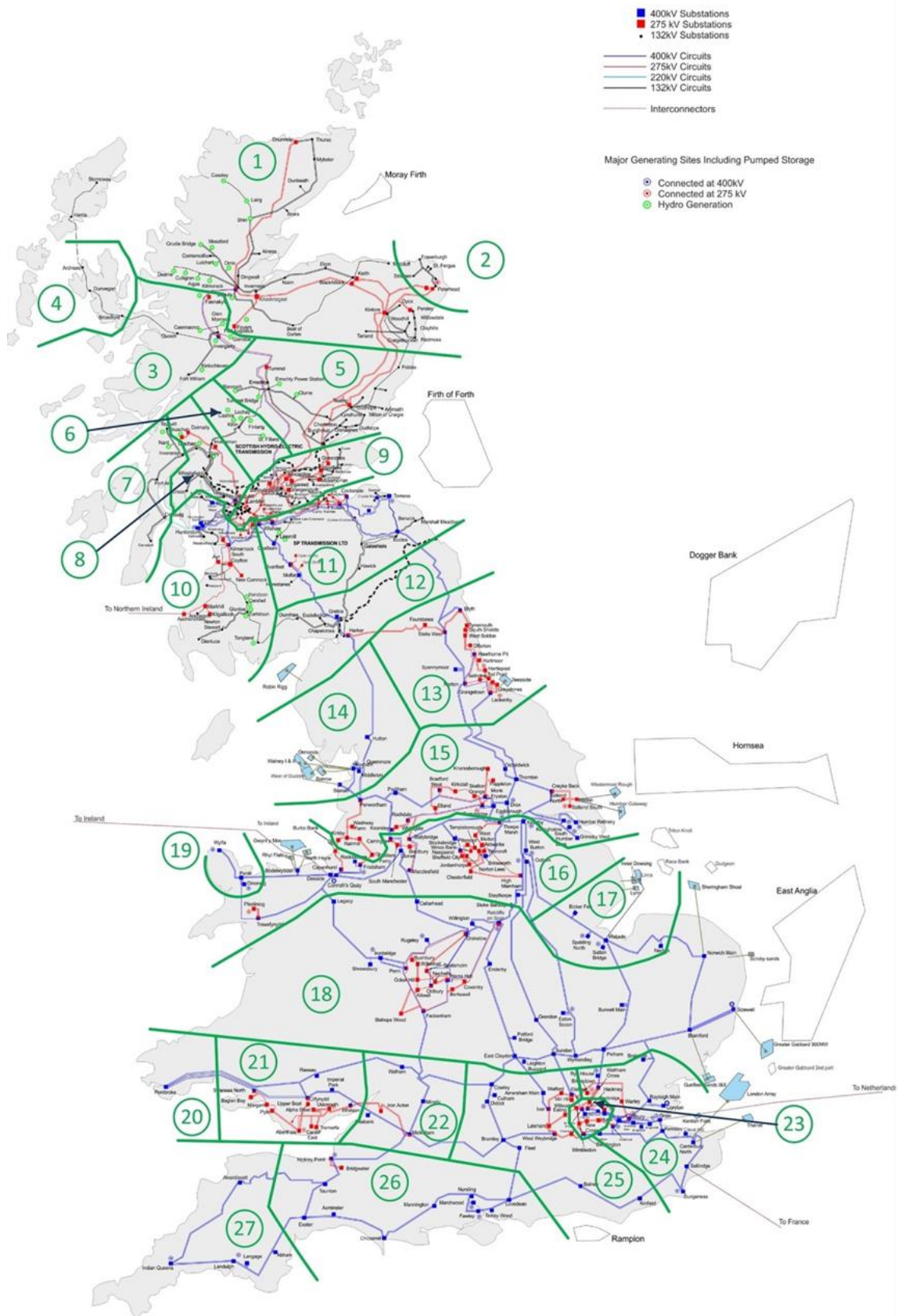
NIC payments are not included as they do not form part of OFTO Maximum Revenue



H

Appendix H: Generation zones map

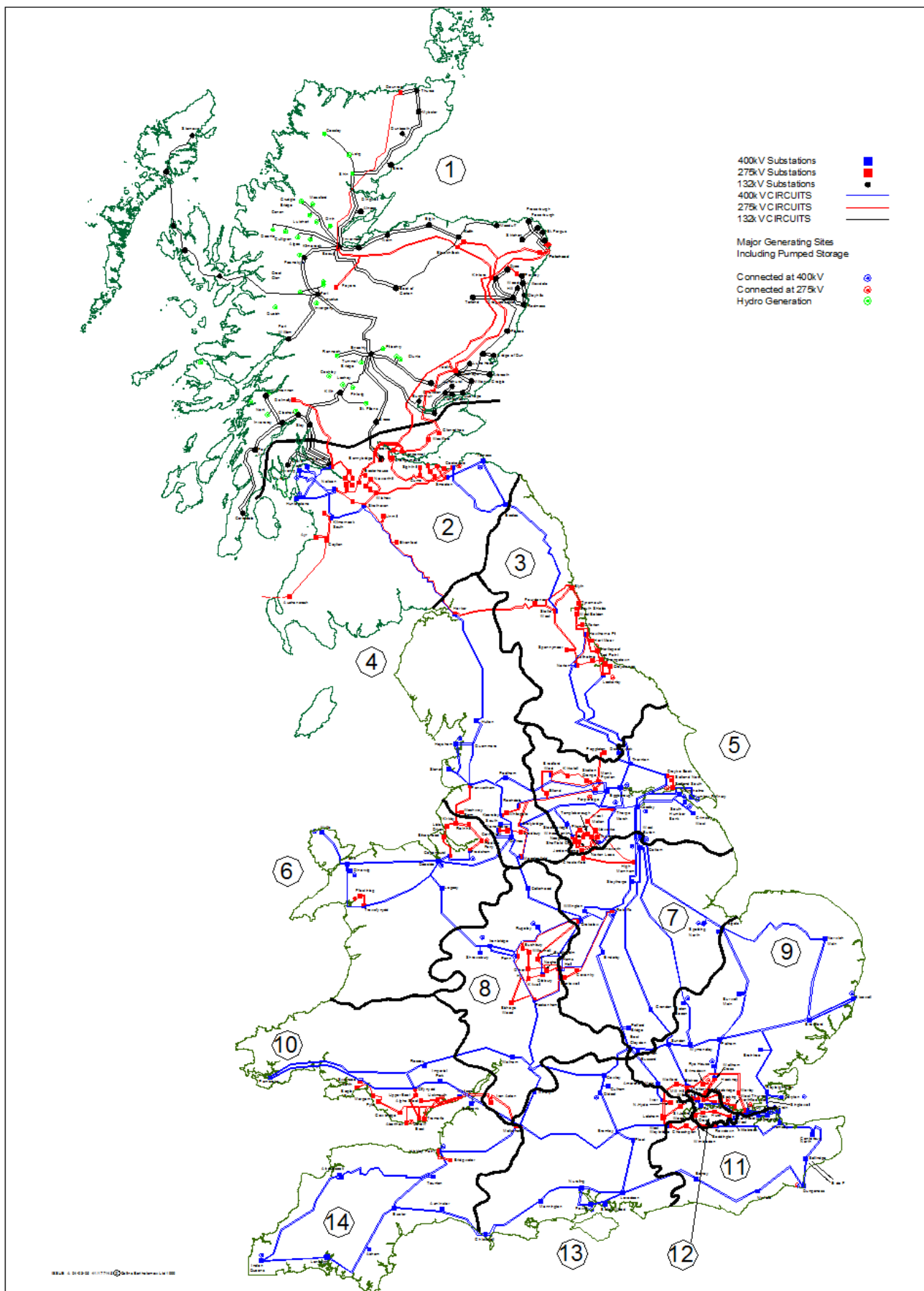
Figure A2: GB Existing Transmission System





I

Appendix I: Demand zones map





J

Appendix J: 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.

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

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