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Five-Year View of TNUoS Tariffs for 2022/23 to 2026/27

National Grid Electricity System Operator

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nationalgridESO

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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 2022/23 - 2026/27.

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 of future TNUoS tariffs regularly on our website[1]. This report provides the forecast for the period of 2022/23 to 2026/27 and also includes the initial quarterly forecast of TNUoS tariffs for year 2022/23.

We fully appreciate that there are uncertainties with several ongoing charging methodology changes. We therefore have also included a number of sensitivity scenario analysis to help the industry to understand the potential implications. Due to a lack of data and clarity on some of the methodology changes, we cannot undertake meaningful analysis for some of the regulatory changes such as access and forward-looking charges.

Major Regulatory Changes - TCR

In this forecast, we have included Transmission Demand Residual (TDR) banded charges methodology from 2023/24, according to Ofgem's minded-to decision. We have assumed four transmission connected bands and floored demand location tariffs in the base case as this will help to provide a like for like comparison to our last 5 year view. This, however, does not represent our view of the pending regulatory changes which are subject to Ofgem's final decision. We have provided a sensitivity analysis for other scenarios incl. different transmission connected banding and non-floored locational tariffs.

Total revenues to be recovered

The total TNUoS revenue to be collected is forecast at £3,366m for 2022/23 (an increase of £47.4m from the current financial year), rising to £3,550.2m in 2026/27. Offshore revenue is forecast to increase steadily in the next five years, offset by the downward trend in onshore TOs revenues under their RIIO-2 business plan. The 2022/23 revenue forecast will be updated through the year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions.

Generation tariffs

The forecasted generation revenue is £836.2m for year 2022/23 (an increase of ~£61m from the current charging year). It would grow to £1193m by 2026/27, mainly driven by the increase in offshore local charges.

The generation charging base for 2022/23 has been forecasted as 74.9GW based on our best view, an increase of 3.8GW from 2021/22. This view will be further refined throughout the year. The average generation tariff for 2022/23 is forecast at £11.06/kW, an increase of £0.03/kW from the 2021/22 average generation tariff. The average generation tariff is expected to increase to £14.73/kW by 2026/27, mainly due to the increase in the generation charging base and increase in local charges.

Demand tariffs

Revenue to be collected through demand for year 2022/23 is forecast at £2,529.8m (a reduction of £18m from current charging year). Demand revenue will continue to reduce year on year to £2,337.6m by 2025/26, with a slight increase the following year (2026/27) to £2,357.2m. The main driver for this trend is the increasing proportion of revenue to be collected through generation in comparison to the increase in total revenue.

The impact on the average end consumer bill is forecast to be £36.38 for 2022/23, a slight decrease of £0.03 compared to current year. This equates to 5.94% of the average annual electricity consumer bill. Assuming implementation of TDR in 2023/24, the TNUoS charge impact will reduce by circa £4 to £32.31 (5.28% of average annual electricity bill).

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

In 2022/23, £14m would be payable to embedded generators (<100MW) through the Embedded Export Tariff (EET), a reduction of £0.9m compared to the current year, mainly driven by the reduction in locational demand tariffs and a drop in forecast embedded generation export. This trend continues through to 2025/26 with the total payable dropping to £12.7m, whilst for 2026/27 there is a noticeable increase to £15m, this is due to the increase in forecast embedded export and in the areas where there are higher tariffs. The average EET for 2022/23 remains the similar level for the current year at £2.14/kW. The average EET fluctuates year on year with a low of £1.88/kW in 2024/25 and a high in 2026/27 of £2.18/kW.

The average HH tariff for 2022/23 is forecast to be £51.39/kW, an increase of £0.03/kW from the current year. The average NHH tariff is forecast at 6.5p/kWh, with minimal change from the current year.

In light of the TDR changes, demand tariffs are expected to decrease significantly from 2023/24 onwards and will be solely based on locational demand charges. With the removal of the demand residual (non-locational charge) from the standard HH / NHH tariff methodology, the implementation of the demand residual banded charges will create an additional charge for final demand sites, in the form of a £ per site per annum (pence per site per day) for both HH and NHH demand.

Sensitivity Scenarios

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

- Impact of new interconnectors
- Alternative T-connected bandings
- Demand tariffs if the locational tariffs are not floored

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

Next TNUoS tariff publication

The timetable of TNUoS tariffs forecasts for 2022/23 is available on our website[2].

Our next TNUoS tariff publication will be the quarterly update forecast of 2022/23 tariffs in August 2021.

Feedback

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

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

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

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

Our contact details

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[2] https://www.nationalgrideso.com/document/186171/download

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Charging Methodology Changes

This Report

This report contains the five-year view on TNUoS tariffs for the charging years 2022/23 – 2026/27, and the initial quarterly forecast of TNUoS for the charging year 2022/23.

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 are expected to 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.

The following section details the changes to the TNUoS methodology.

COVID19 Impact

During 2020/21 we observed unprecedented levels of low demand in Great Britain due to the impact of COVID19 and the corresponding periods of lockdown. Along with the low levels of demand, there was a shift in HH and NHH consumptions, both of which created increased uncertainty in the demand forecast that feed into TNUoS demand tariffs. Our view was that whilst it is anticipated that the impact of COVID19 on demand will continue into 2021/22 there will be a steady shift towards 'normal' demand levels as the year progresses, but 'economic scaring' will still be present.

In this five-year view, the same approach/assumptions apply for 2022/23 onwards, the return to 'normal' can be seen in the demand charging bases, with the average gross demand and HH demand at triad stabilising, as well as NHH returning to levels forecast pre-COVID. It is worth noting that overall there has been a slight reduction in the demand charging bases versus previous five year forecasts, this view ties in the with trends seen in our wider ESO publications. The indicative under recovery for 2020/21 is £41m. Once the under recovery is finalised, it will be collected via 2022/23 TNUoS charges.

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

On 21 November 2019, Ofgem published their final decision[3] 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. The changes have been implemented in April 2021 for the Transmission Generation Residual (TGR) changes in line with CMP317/327. Ofgem's minded-to position for the Transmission Demand Residual (TDR) changes is to implement in April 2023.

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

- TGR - The removal of the generation residual, which was used to keep total TNUoS recovery from generators within the range of €0-2.50/MWh. This change was managed under CMP317/327, which sought to ensure ongoing compliance with European Regulation by establishing which charges are and are not in scope of that range. The final decision of CMP317/327 means that all local charges are not in scope but with a few exclusions. As a result, we have raised follow-up CUSC mod (CMP368/369), to exclude certain elements in local charges and generation volume and charges associated with TNUoS-liable embedded generators;
- TDR - The creation of 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.

Under the existing TNUoS methodology, the demand charging base is one of the key inputs for setting the demand tariffs. Forecasting the demand charging base, in particular the net system peak demand (Triads), at year ahead can be challenging. The variance between the demand

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

forecasts used for tariff setting and outturn (actual demand) has been one of the biggest impacts on under/over recovery of TNUoS revenue. The under/over recovery of TNUoS revenue is defined as K factor in the electricity transmission licence.

Under the new TDR methodology, the demand forecast is not used in setting the demand residual tariff. Instead, the demand residual tariff requires an estimate of the number of sites in each band. The accuracy of the tariffs now depends on the quality of site count data which we would receive from the DNOs and iDNOs. We note that unlike demand outturns, we have no means to validate or verify the site data received from DNOs and iDNOs, and so the burden of ensuring accuracy in tariff setting does not lie solely with the ESO.

The locational demand charge is currently within scope of the Access and Forward-Looking Charges Significant Code Review led by Ofgem. The existing methodology requires the demand forecast for Triads in setting locational demand tariffs. Therefore under/over recovery of locational demand revenue is still affected by the accuracy of demand forecasts, albeit to a significantly lesser degree given the relative size of the locational and residual elements.

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 TDR which are expected to take effect from April 2023 and our current understanding of CMP368/369 to illustrate the likely magnitudes of tariffs changes to customers.

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 SCR[4]. 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 have set out their intent to bring forward an earlier minded to decision in Spring 2021 on TNUoS reforms for distributed generation, access rights and distribution connection charging reforms. 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 minded-to decision is published, and when the policy intent is understood.

Potential changes to the TNUoS revenue parameters

In March 2021, CMA (Competition and Market Authority) received multiple appeals by nine energy companies over RIIO price control[5] decisions. CMA will make their final determination on the appeals by 30th October 2021. If the appeals were approved, some underlying parameters for onshore TOs' revenue calculation (e.g. cost of equity and outperformance wedge) may change. The likely changes to TOs' revenue figures, as a result of alternative rate of return value, is unknown to the ESO, and to avoid confusing our customers, we have not attempted to undertake any revenue sensitivity analysis. Changes to the TNUoS revenue figure will impact demand users only, via demand residual tariffs (switching to TDR charges from 2023/24 onwards). As a very high-level indication, assuming the total demand charging base is 50GW, if the revenue increases by £50m, the demand residual tariff will increase by £1/kW.

Other charging methodology changes

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

[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.gov.uk/cma-cases/energy-licence-modification-appeals-2021

In this report, we have incorporated CMP343 (Transmission Demand Residual reform) and CMP368/369 (Updating Charges for the purpose of maintaining compliance with the Limiting Regulation) in the baseline forecast.

Under CMP353 (Stabilising the Expansion Constant and non-specific Onshore Expansion Factors from 1st April 2021), it is confirmed that the Expansion Constant would be held at the RIIO-1 (inflated) value whilst further review is undertaken with the industry.

There are also a number of 'in-flight' proposals to change the charging methodologies. These are summarised in the CUSC modifications Table 27.

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Generation tariffs

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

1. Generation tariffs summary

This section summarises our view of generation tariffs from 2022/23 to 2026/27 and how these tariffs were calculated.

This forecast includes the implementation of the TGR, which took effect from April 2021. All local onshore and local offshore tariffs are not included in the European €2.50/MWh cap for generator transmission charges in line with the final decision on CMP317/327 with a few exceptions to be clarified under CMP368/389. To provide an indicative view of the likely tariffs under CMP368/389, when calculating the generation adjustment tariff for the European cap compliance, we have included local charges associated with pre-existing transmission assets (based on our preliminary understanding of the concept, and the available data to us). We have excluded wider charges associated with TNUoS-liable large embedded generators in the total generation charge, and excluded expected generation outputs from those large embedded generators.,

Table 1 Summary of average generation tariffs

Generation Tariffs (£/kW)	Final 2021/22	April 2022/23	Five-year View			
			2023/24	2024/25	2025/26	2026/27
Adjustment	- 0.432600	- 0.418310	- 0.428579	- 0.794656	- 2.512418	- 3.537638
Average Generation Tariff*	11.035859	11.064100	12.302798	14.064472	14.476138	14.732231

*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.

The generation adjustment 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. The implementation of CMP317/327 means that charges for local onshore and offshore tariffs are not included in the European €2.50/MWh cap.

Over the next five years, it is expected that the average generation tariff will increase from £11.06/kW in 2022/23 to £14.73/kW by 2026/27. This is mainly driven by the increase in generation revenue caused by the increase in local charges and the asset transfer of offshore generators.

2. Generation wider tariffs

The following section summarises the five-year view of wider generation tariffs from 2022/23 to 2026/27. 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 was discontinued from 1st April 2021 and has not been included in the tariffs.

Table 2 Generation wider tariffs in 2022/23

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 80% Load Factor (£/kW)	Conventional Low Carbon 80% Load Factor (£/kW)	Intermittent 40% Load Factor (£/kW)
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)			
1	North Scotland	3.741782	18.296631	16.505194	-0.418310	31.164932	34.465971	23.405536
2	East Aberdeenshire	4.691757	10.246043	16.505194	-0.418310	25.674437	28.975475	20.185301
3	Western Highlands	3.720650	16.673356	15.815023	-0.418310	29.293043	32.456048	22.066055
4	Skye and Lochalsh	-0.763050	16.673356	17.617333	-0.418310	26.251191	29.774658	23.868365
5	Eastern Grampian and Tayside	4.902200	14.864758	14.707373	-0.418310	28.141595	31.083069	20.234966
6	Central Grampian	5.149273	13.770176	13.832661	-0.418310	26.813233	29.579765	18.922421
7	Argyll	3.881575	11.413590	19.573295	-0.418310	28.252773	32.167432	23.720421
8	The Trossachs	4.957950	11.413590	11.898891	-0.418310	23.189625	25.569403	16.046017
9	Stirlingshire and Fife	3.234419	9.786051	10.951646	-0.418310	19.406267	21.596596	14.447756
10	South West Scotland	4.176293	10.321155	11.229025	-0.418310	20.998127	23.243932	14.939177
11	Lothian and Borders	3.372113	10.321155	5.683776	-0.418310	15.757748	16.894503	9.393928
12	Solway and Cheviot	2.657155	7.021104	6.552912	-0.418310	13.098058	14.408640	8.943044
13	North East England	4.303098	5.217606	3.846663	-0.418310	11.136203	11.905536	5.515395
14	North Lancashire and The Lakes	2.169932	5.217606	1.856779	-0.418310	7.411130	7.782486	3.525511
15	South Lancashire, Yorkshire and Humber	5.148616	1.825281	0.222027	-0.418310	6.368152	6.412558	0.533829
16	North Midlands and North Wales	4.115189	0.746386	-	-0.418310	4.293988	4.293988	-0.119756
17	South Lincolnshire and North Norfolk	2.848430	0.550082	-	-0.418310	2.870186	2.870186	-0.198277
18	Mid Wales and The Midlands	1.081314	1.903261	-	-0.418310	2.185613	2.185613	0.342994
19	Anglesey and Snowdon	5.487186	0.910337	-	-0.418310	5.797146	5.797146	-0.054175
20	Pembrokeshire	7.086954	-4.426772	-	-0.418310	3.127226	3.127226	-2.189019
21	South Wales & Gloucester	3.059071	-5.726439	-	-0.418310	-1.940390	-1.940390	-2.708886
22	Cotswold	3.518495	3.583833	-9.008442	-0.418310	-1.239502	-3.041191	-7.993219
23	Central London	-5.636848	3.583833	-7.194942	-0.418310	-8.944045	-10.383034	-6.179719
24	Essex and Kent	-3.664040	3.583833	-	-0.418310	-1.215284	-1.215284	1.015223
25	Oxfordshire, Surrey and Sussex	-0.785754	-1.702331	-	-0.418310	-2.565929	-2.565929	-1.099242
26	Somerset and Wessex	-1.999625	-2.874470	-	-0.418310	-4.717511	-4.717511	-1.568098
27	West Devon and Cornwall	-1.850698	-7.524237	-	-0.418310	-8.288398	-8.288398	-3.428005

Table 3 Generation wider tariffs in 2023/24

Zone	Generation Tariffs Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 80% Load Factor (£/kW)	Conventional Low Carbon 80% Load Factor (£/kW)	Intermittent 40% Load Factor (£/kW)
1	North Scotland	3.926352	19.053551	16.817432	-0.428579	32.194559	35.558046	24.010273
2	East Aberdeenshire	4.409432	10.937303	16.817432	-0.428579	26.184641	29.548127	20.763774
3	Western Highlands	3.465040	16.903088	15.814851	-0.428579	29.210812	32.373782	22.147507
4	Skye and Lochalsh	-1.116270	16.903088	17.659419	-0.428579	26.105157	29.637040	23.992075
5	Eastern Grampian and Tayside	4.689969	15.219081	14.714387	-0.428579	28.208164	31.151042	20.373440
6	Central Grampian	4.290907	13.951270	13.649207	-0.428579	25.942710	28.672551	18.801136
7	Argyll	2.963497	11.507858	19.239100	-0.428579	27.132484	30.980304	23.413664
8	The Trossachs	3.927908	11.507858	11.543902	-0.428579	21.940737	24.249517	15.718466
9	Stirlingshire and Fife	3.157849	10.548077	10.954935	-0.428579	19.931680	22.122667	14.745587
10	South West Scotland	2.650203	11.146639	11.283030	-0.428579	20.165359	22.421965	15.313107
11	Lothian and Borders	3.439760	11.146639	5.778372	-0.428579	16.551190	17.706864	9.808449
12	Solway and Cheviot	2.435450	7.556430	6.392746	-0.428579	13.166212	14.444761	8.986739
13	North East England	3.737022	5.941341	4.057827	-0.428579	11.307777	12.119343	6.005784
14	North Lancashire and The Lakes	2.239964	5.941341	0.909833	-0.428579	7.292324	7.474291	2.857790
15	South Lancashire, Yorkshire and Humber	4.395014	2.408655	0.385555	-0.428579	6.201803	6.278914	0.920438
16	North Midlands and North Wales	3.579680	0.702187		-0.428579	3.712851	3.712851	-0.147704
17	South Lincolnshire and North Norfolk	3.290410	2.258326		-0.428579	4.668492	4.668492	0.474751
18	Mid Wales and The Midlands	-0.177180	3.778724		-0.428579	2.417220	2.417220	1.082911
19	Anglesey and Snowdon	5.985601	-0.001671		-0.428579	5.555685	5.555685	-0.429247
20	Pembrokeshire	6.751019	-6.544839		-0.428579	1.086569	1.086569	-3.046515
21	South Wales & Gloucester	2.149792	-7.626404		-0.428579	-4.379910	-4.379910	-3.479141
22	Cotswold	1.654310	4.687983	-11.104644	-0.428579	-3.907598	-6.128527	-9.658030
23	Central London	-3.573820	4.687983	-5.714256	-0.428579	-4.823417	-5.966269	-4.267642
24	Essex and Kent	-3.216885	4.687983		-0.428579	0.104922	0.104922	1.446614
25	Oxfordshire, Surrey and Sussex	-0.549596	-1.121593		-0.428579	-1.875449	-1.875449	-0.877216
26	Somerset and Wessex	-2.379481	-1.771293		-0.428579	-4.225094	-4.225094	-1.137096
27	West Devon and Cornwall	-3.027382	-8.877761		-0.428579	-10.558170	-10.558170	-3.979683

Table 4 Generation wider tariffs in 2024/25

Zone	Generation Tariffs Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 80% Load Factor (£/kW)	Conventional Low Carbon 80% Load Factor (£/kW)	Intermittent 40% Load Factor (£/kW)
1	North Scotland	3.228161	15.922323	18.664738	-0.794656	30.103154	33.836101	24.239011
2	East Aberdeenshire	4.250525	8.142102	18.664738	-0.794656	24.901341	28.634289	21.126923
3	Western Highlands	2.997512	15.037159	18.001873	-0.794656	28.634082	32.234456	23.222081
4	Skye and Lochalsh	-1.680886	15.037159	19.912713	-0.794656	25.484356	29.466898	25.132921
5	Eastern Grampian and Tayside	4.387196	13.717591	16.721655	-0.794656	27.943937	31.288268	21.414035
6	Central Grampian	4.388060	12.198590	14.878152	-0.794656	25.254798	28.230428	18.962932
7	Argyll	3.619144	10.347591	19.779364	-0.794656	26.926052	30.881925	23.123744
8	The Trossachs	3.564477	10.347591	12.592019	-0.794656	21.121509	23.639913	15.936399
9	Stirlingshire and Fife	2.479158	9.551003	11.873878	-0.794656	18.824407	21.199182	14.899623
10	South West Scotlands	1.736632	9.731310	12.021562	-0.794656	18.344274	20.748586	15.119430
11	Lothian and Borders	3.374947	9.731310	7.170162	-0.794656	16.101469	17.535501	10.268030
12	Solway and Cheviot	1.302351	6.614974	6.280539	-0.794656	10.824105	12.080213	8.131873
13	North East England	3.356563	5.652913	4.427803	-0.794656	10.626480	11.512040	5.894312
14	North Lancashire and The Lakes	1.255895	5.652913	0.348719	-0.794656	5.262545	5.332288	1.815228
15	South Lancashire, Yorkshire and Humber	4.130216	2.265403	0.838674	-0.794656	5.818822	5.986556	0.950179
16	North Midlands and North Wales	3.367914	0.325194		-0.794656	2.833413	2.833413	-0.664578
17	South Lincolnshire and North Norfolk	3.593202	2.819282		-0.794656	5.053972	5.053972	0.333057
18	Mid Wales and The Midlands	0.578087	5.318168		-0.794656	4.037965	4.037965	1.332611
19	Anglesey and Snowdon	5.922122	-0.516703		-0.794656	4.714104	4.714104	-1.001337
20	Pembrokeshire	7.810953	-6.402058		-0.794656	1.894651	1.894651	-3.355479
21	South Wales & Gloucester	2.887311	-7.011841		-0.794656	-3.516818	-3.516818	-3.599392
22	Cotswold	1.504294	5.515635	-12.517820	-0.794656	-4.892110	-7.395674	-11.106222
23	Central London	-3.646896	5.515635	-6.278502	-0.794656	-5.051846	-6.307546	-4.866904
24	Essex and Kent	-2.755642	5.515635		-0.794656	0.862210	0.862210	1.411598
25	Oxfordshire, Surrey and Sussex	-0.433405	-0.690925		-0.794656	-1.780801	-1.780801	-1.071026
26	Somerset and Wessex	-1.843181	-1.451260		-0.794656	-3.798845	-3.798845	-1.375160
27	West Devon and Cornwall	-2.376864	-9.597891		-0.794656	-10.849833	-10.849833	-4.633812

Table 5 Generation wider tariffs in 2025/26

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.822640	15.439825	23.813798	-2.512418	31.713120	36.475880	27.477310
2	East Aberdeenshire	4.460623	5.137691	23.813798	-2.512418	25.109396	29.872156	23.356456
3	Western Highlands	2.210209	13.519946	21.612930	-2.512418	27.804092	32.126678	24.508490
4	Skye and Lochalsh	2.158312	13.519946	28.279425	-2.512418	33.085391	38.741276	31.174985
5	Eastern Grampian and Tayside	4.361992	11.067239	18.217074	-2.512418	25.277024	28.920439	20.131552
6	Central Grampian	3.819417	11.003658	18.086178	-2.512418	24.578868	28.196103	19.975223
7	Argyll	2.462464	9.534307	24.499386	-2.512418	27.177000	32.076878	25.800691
8	The Trossachs	3.429370	9.534307	15.029670	-2.512418	20.568134	23.574068	16.330975
9	Stirlingshire and Fife	2.187342	9.050668	14.252519	-2.512418	18.317474	21.167977	15.360368
10	South West Scotlands	1.963969	9.286744	14.602605	-2.512418	18.563030	21.483551	15.804885
11	Lothian and Borders	2.284228	9.286744	8.799999	-2.512418	14.241204	16.001204	10.002279
12	Solway and Cheviot	1.385205	6.824575	8.330643	-2.512418	10.996961	12.663090	8.548055
13	North East England	2.573081	5.609119	4.964097	-2.512418	8.519236	9.512055	4.695327
14	North Lancashire and The Lakes	1.217504	5.609119	1.665175	-2.512418	4.524521	4.857556	1.396405
15	South Lancashire, Yorkshire and Humber	2.924003	3.209929	1.043556	-2.512418	3.814373	4.023084	-0.184890
16	North Midlands and North Wales	2.748212	1.387250	-0.532670	-2.512418	0.919458	0.812924	-2.490188
17	South Lincolnshire and North Norfolk	3.303801	3.598764	-0.173638	-2.512418	3.531484	3.496756	-1.246550
18	Mid Wales and The Midlands	0.789000	4.720846	-0.056685	-2.512418	2.007911	1.996574	-0.680765
19	Anglesey and Snowdon	5.769546	0.894868	-0.532670	-2.512418	3.546886	3.440352	-2.687141
20	Pembrokeshire	8.083019	-6.602743		-2.512418	0.288407	0.288407	-5.153515
21	South Wales & Gloucester	3.077610	-7.035223		-2.512418	-5.062986	-5.062986	-5.326507
22	Cotswold	1.690451	5.355530	-12.745878	-2.512418	-6.734245	-9.283421	-13.116084
23	Central London	-3.373643	5.355530	-6.522345	-2.512418	-6.819513	-8.123982	-6.892551
24	Essex and Kent	-2.500640	5.355530		-2.512418	-0.728634	-0.728634	-0.370206
25	Oxfordshire, Surrey and Sussex	-0.163446	-0.878515		-2.512418	-3.378676	-3.378676	-2.863824
26	Somerset and Wessex	-1.668149	-1.942812		-2.512418	-5.734817	-5.734817	-3.289543
27	West Devon and Cornwall	-2.236341	-9.873314		-2.512418	-12.647410	-12.647410	-6.461744

Table 6 Generation wider tariffs in 2026/27

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Adjustment Tariff	Conventional Carbon 80% Load Factor	Conventional Low Carbon 80% Load Factor	Intermittent 40% Load Factor
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	2.192544	14.730960	25.308994	-3.537638	30.686869	35.748668	27.663740
2	East Aberdeenshire	4.110529	5.600336	25.308994	-3.537638	25.300355	30.362154	24.011490
3	Western Highlands	2.496419	13.259313	23.141193	-3.537638	28.079186	32.707424	24.907280
4	Skye and Lochalsh	2.440073	13.259313	29.952190	-3.537638	33.471637	39.462075	31.718277
5	Eastern Grampian and Tayside	5.396491	11.307145	19.642321	-3.537638	26.618426	30.546890	20.627541
6	Central Grampian	4.485725	11.053652	19.005111	-3.537638	24.995097	28.796120	19.888934
7	Argyll	2.540652	9.936303	28.691888	-3.537638	29.905567	35.643944	29.128771
8	The Trossachs	3.414573	9.936303	16.172438	-3.537638	20.763928	23.998415	16.609321
9	Stirlingshire and Fife	2.092205	9.449718	15.194426	-3.537638	18.269882	21.308767	15.436675
10	South West Scotlands	2.040642	9.573379	15.424719	-3.537638	18.501482	21.586426	15.716433
11	Lothian and Borders	2.260813	9.573379	9.386909	-3.537638	13.891405	15.768787	9.678623
12	Solway and Cheviot	1.730944	7.305795	8.793905	-3.537638	11.073066	12.831847	8.178585
13	North East England	2.821452	6.142710	5.107410	-3.537638	8.283910	9.305392	4.026856
14	North Lancashire and The Lakes	1.400089	6.142710	2.202935	-3.537638	4.538967	4.979554	1.122381
15	South Lancashire, Yorkshire and Humber	3.194010	3.823162	0.827448	-3.537638	3.376860	3.542350	-1.180925
16	North Midlands and North Wales	2.743480	2.336582	-0.607261	-3.537638	0.589299	0.467847	-3.210266
17	South Lincolnshire and North Norfolk	2.737284	4.790389	-0.071117	-3.537638	2.975064	2.960840	-1.692599
18	Mid Wales and The Midlands	0.875417	4.675807	-0.090969	-3.537638	1.005649	0.987456	-1.758284
19	Anglesey and Snowdon	5.606623	2.166190	-0.607261	-3.537638	3.316128	3.194676	-3.278423
20	Pembrokeshire	4.196418	-10.158788		-3.537638	-7.468250	-7.468250	-7.601153
21	South Wales & Gloucester	1.635838	-9.141854		-3.537638	-9.215283	-9.215283	-7.194380
22	Cotswold	-0.022750	5.268761	-14.070072	-3.537638	-10.601437	-13.415451	-15.500206
23	Central London	-2.810144	5.268761	-6.379246	-3.537638	-7.236170	-8.512019	-7.809380
24	Essex and Kent	-2.104877	5.268761		-3.537638	-1.427506	-1.427506	-1.430134
25	Oxfordshire, Surrey and Sussex	-0.119674	-1.229576		-3.537638	-4.640973	-4.640973	-4.029468
26	Somerset and Wessex	-1.632621	-2.596698		-3.537638	-7.247617	-7.247617	-4.576317
27	West Devon and Cornwall	-2.090091	-10.962696		-3.537638	-14.397886	-14.397886	-7.922716

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

The following section provides details of the wider generation tariffs for 2022/23 to 2026/27 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 implementation 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.

Table 7 Comparison of Conventional Carbon (80%) tariffs

Wider Tariffs for a Conventional Carbon 80% Generator		2022/23	2023/24	2024/25	2025/26	2026/27
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	31.165	32.195	30.103	31.713	30.687
2	East Aberdeenshire	25.674	26.185	24.901	25.109	25.300
3	Western Highlands	29.293	29.211	28.634	27.804	28.079
4	Skye and Lochalsh	26.251	26.105	25.484	33.085	33.472
5	Eastern Grampian and Tayside	28.142	28.208	27.944	25.277	26.618
6	Central Grampian	26.813	25.943	25.255	24.579	24.995
7	Argyll	28.253	27.132	26.926	27.177	29.906
8	The Trossachs	23.190	21.941	21.122	20.568	20.764
9	Stirlingshire and Fife	19.406	19.932	18.824	18.317	18.270
10	South West Scotland	20.998	20.165	18.344	18.563	18.501
11	Lothian and Borders	15.758	16.551	16.101	14.241	13.891
12	Solway and Cheviot	13.098	13.166	10.824	10.997	11.073
13	North East England	11.136	11.308	10.626	8.519	8.284
14	North Lancashire and The Lakes	7.411	7.292	5.263	4.525	4.539
15	South Lancashire, Yorkshire and Humber	6.368	6.202	5.819	3.814	3.377
16	North Midlands and North Wales	4.294	3.713	2.833	0.919	0.589
17	South Lincolnshire and North Norfolk	2.870	4.668	5.054	3.531	2.975
18	Mid Wales and The Midlands	2.186	2.417	4.038	2.008	1.006
19	Anglesey and Snowdon	5.797	5.556	4.714	3.547	3.316
20	Pembrokeshire	3.127	1.087	1.895	0.288	-7.468
21	South Wales & Gloucester	-1.940	-4.380	-3.517	-5.063	-9.215
22	Cotswold	-1.240	-3.908	-4.892	-6.734	-10.601
23	Central London	-8.944	-4.823	-5.052	-6.820	-7.236
24	Essex and Kent	-1.215	0.105	0.862	-0.729	-1.428
25	Oxfordshire, Surrey and Sussex	-2.566	-1.875	-1.781	-3.379	-4.641
26	Somerset and Wessex	-4.718	-4.225	-3.799	-5.735	-7.248
27	West Devon and Cornwall	-8.288	-10.558	-10.850	-12.647	-14.398

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

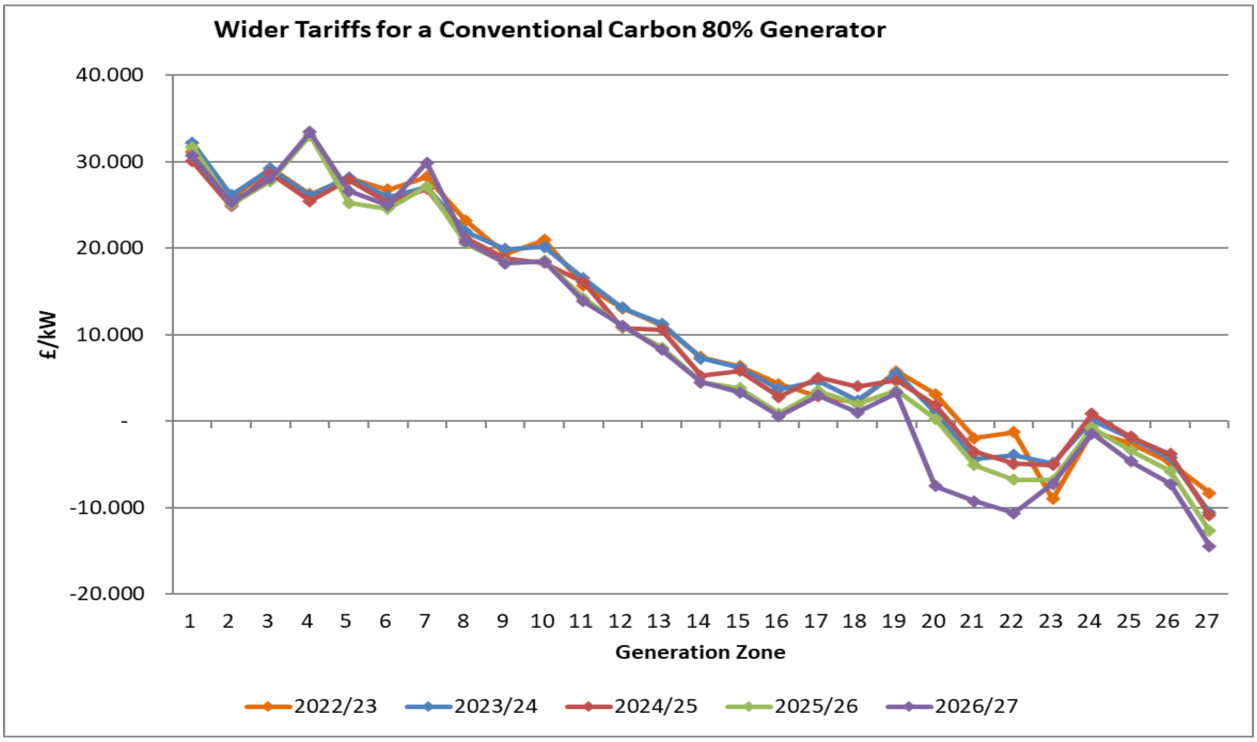


Table 8 Comparison of Conventional Low Carbon (80%) tariffs

Wider Tariffs for a Conventional Low Carbon 80% Generator		2022/23	2023/24	2024/25	2025/26	2026/27
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	34.466	35.558	33.836	36.476	35.749
2	East Aberdeenshire	28.975	29.548	28.634	29.872	30.362
3	Western Highlands	32.456	32.374	32.234	32.127	32.707
4	Skye and Lochalsh	29.775	29.637	29.467	38.741	39.462
5	Eastern Grampian and Tayside	31.083	31.151	31.288	28.920	30.547
6	Central Grampian	29.580	28.673	28.230	28.196	28.796
7	Argyll	32.167	30.980	30.882	32.077	35.644
8	The Trossachs	25.569	24.250	23.640	23.574	23.998
9	Stirlingshire and Fife	21.597	22.123	21.199	21.168	21.309
10	South West Scotland	23.244	22.422	20.749	21.484	21.586
11	Lothian and Borders	16.895	17.707	17.536	16.001	15.769
12	Solway and Cheviot	14.409	14.445	12.080	12.663	12.832
13	North East England	11.906	12.119	11.512	9.512	9.305
14	North Lancashire and The Lakes	7.782	7.474	5.332	4.858	4.980
15	South Lancashire, Yorkshire and Humber	6.413	6.279	5.987	4.023	3.542
16	North Midlands and North Wales	4.294	3.713	2.833	0.813	0.468
17	South Lincolnshire and North Norfolk	2.870	4.668	5.054	3.497	2.961
18	Mid Wales and The Midlands	2.186	2.417	4.038	1.997	0.987
19	Anglesey and Snowdon	5.797	5.556	4.714	3.440	3.195
20	Pembrokeshire	3.127	1.087	1.895	0.288	-7.468
21	South Wales & Gloucester	-1.940	-4.380	-3.517	-5.063	-9.215
22	Cotswold	-3.041	-6.129	-7.396	-9.283	-13.415
23	Central London	-10.383	-5.966	-6.308	-8.124	-8.512
24	Essex and Kent	-1.215	0.105	0.862	-0.729	-1.428
25	Oxfordshire, Surrey and Sussex	-2.566	-1.875	-1.781	-3.379	-4.641
26	Somerset and Wessex	-4.718	-4.225	-3.799	-5.735	-7.248
27	West Devon and Cornwall	-8.288	-10.558	-10.850	-12.647	-14.398

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

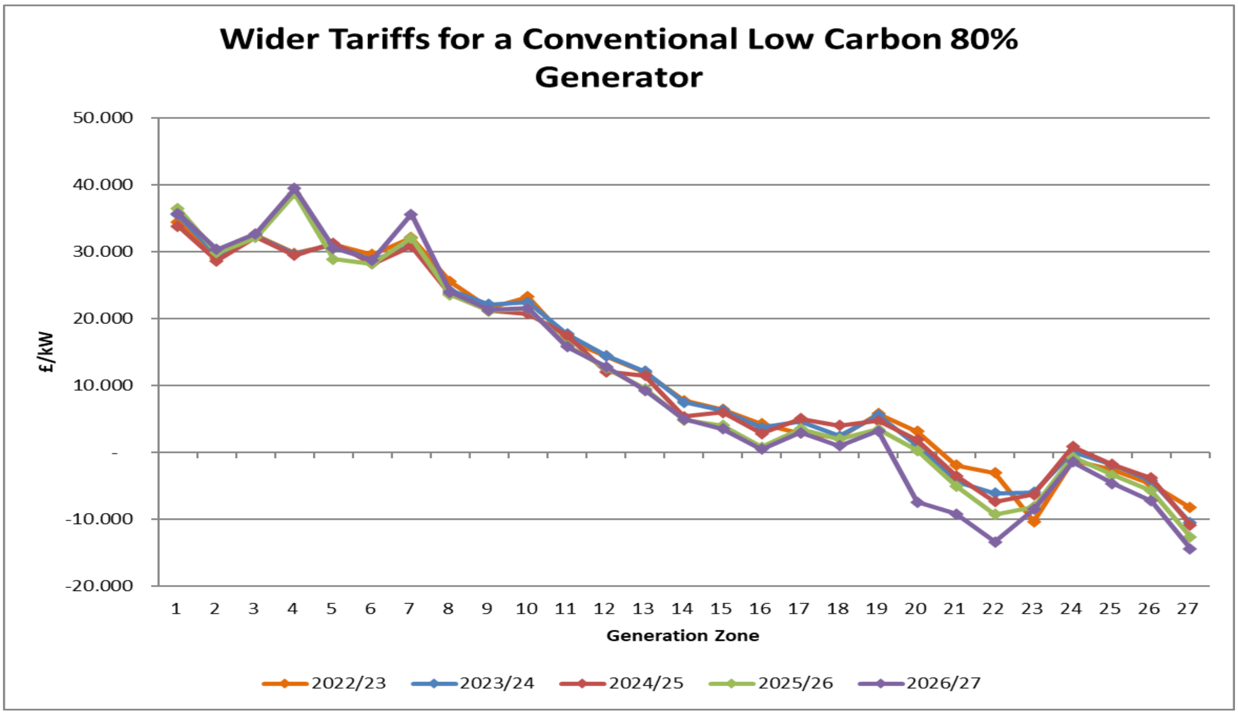
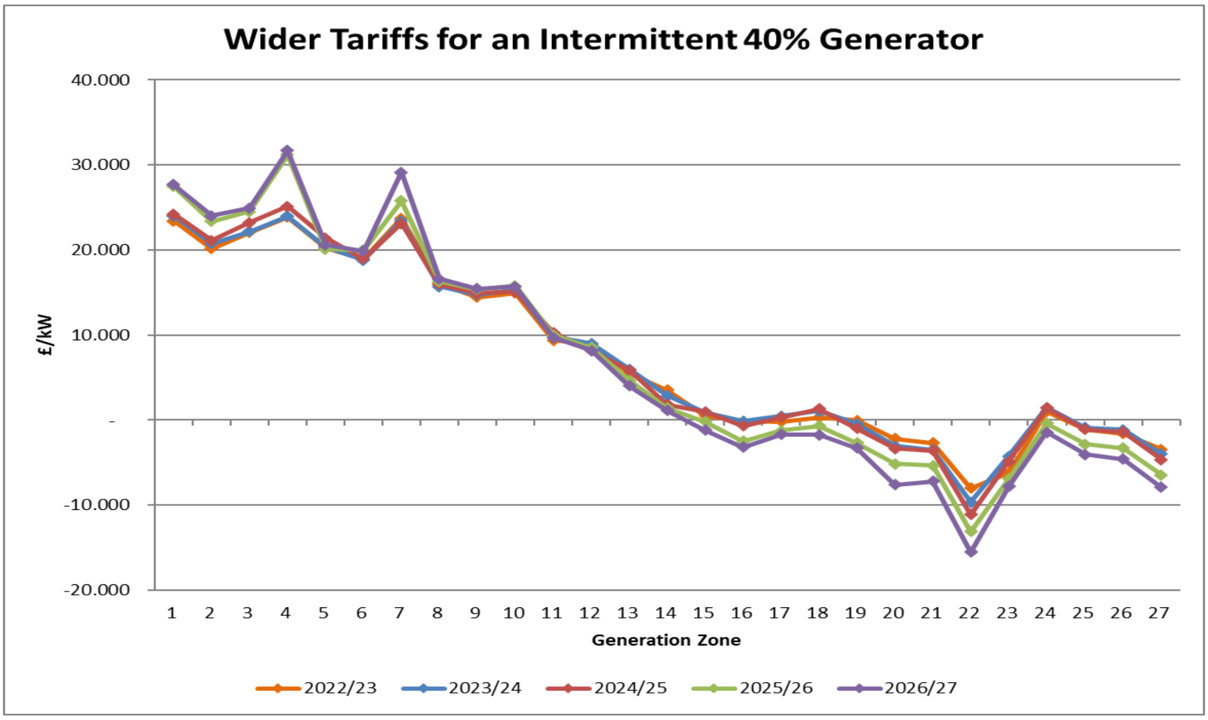


Table 9 Comparison of Intermittent (40%) tariffs

Wider Tariffs for an Intermittent 40% Generator		2022/23	2023/24	2024/25	2025/26	2026/27
Zone	Zone Name	(£/kW)	(£/kW)	(£/kW)	(£/kW)	(£/kW)
1	North Scotland	23.406	24.010	24.239	27.477	27.664
2	East Aberdeenshire	20.185	20.764	21.127	23.356	24.011
3	Western Highlands	22.066	22.148	23.222	24.508	24.907
4	Skye and Lochalsh	23.868	23.992	25.133	31.175	31.718
5	Eastern Grampian and Tayside	20.235	20.373	21.414	20.132	20.628
6	Central Grampian	18.922	18.801	18.963	19.975	19.889
7	Argyll	23.720	23.414	23.124	25.801	29.129
8	The Trossachs	16.046	15.718	15.936	16.331	16.609
9	Stirlingshire and Fife	14.448	14.746	14.900	15.360	15.437
10	South West Scotland	14.939	15.313	15.119	15.805	15.716
11	Lothian and Borders	9.394	9.808	10.268	10.002	9.679
12	Solway and Cheviot	8.943	8.987	8.132	8.548	8.179
13	North East England	5.515	6.006	5.894	4.695	4.027
14	North Lancashire and The Lakes	3.526	2.858	1.815	1.396	1.122
15	South Lancashire, Yorkshire and Humber	0.534	0.920	0.950	-0.185	-1.181
16	North Midlands and North Wales	-0.120	-0.148	-0.665	-2.490	-3.210
17	South Lincolnshire and North Norfolk	-0.198	0.475	0.333	-1.247	-1.693
18	Mid Wales and The Midlands	0.343	1.083	1.333	-0.681	-1.758
19	Anglesey and Snowdon	-0.054	-0.429	-1.001	-2.687	-3.278
20	Pembrokeshire	-2.189	-3.047	-3.355	-5.154	-7.601
21	South Wales & Gloucester	-2.709	-3.479	-3.599	-5.327	-7.194
22	Cotswold	-7.993	-9.658	-11.106	-13.116	-15.500
23	Central London	-6.180	-4.268	-4.867	-6.893	-7.809
24	Essex and Kent	1.015	1.447	1.412	-0.370	-1.430
25	Oxfordshire, Surrey and Sussex	-1.099	-0.877	-1.071	-2.864	-4.029
26	Somerset and Wessex	-1.568	-1.137	-1.375	-3.290	-4.576
27	West Devon and Cornwall	-3.428	-3.980	-4.634	-6.462	-7.923

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



Locational changes

Locational tariffs for conventional carbon and conventional low carbon generators are generally expected to remain stable over the next 5 years, with a slight decrease year on year due to the adjustment tariff becoming more negative. In zones 20-22 for conventional carbon and conventional low carbon, there is forecasted to be a drop in the conventional carbon and conventional low carbon tariffs in 2026/27. This is driven by a forecasted decrease of ~3GW of conventional carbon and low carbon generation in these zones, modelled as part of our best view. The best view has been aligned to a 5-year generation forecast central case produced by FES.

For intermittent generators forecasted tariffs would slightly increase in Scotland due to an increase in renewable generation. We have also anticipated a decrease in conventional generation in line with FES over the five years of the forecast, which causes little change in tariffs in zones 8-18.

In zone 4, for all generator types, there is expected to be variations year to year due to the zone being sensitive to changes caused by very little generation connecting in that zone and long radial circuits.

To view the changes in generation in each zone, please see Table A in the accompanying tables spreadsheet published on our website here under 2022/23 tariffs and Table 34 on page 68.

Adjustment tariff changes

The adjustment tariff has been implemented through CMP317/327, where the generation residual has been removed which meant there is a need for an adjustment tariff to ensure compliance with the European cap. The adjustment tariff is forecast to be negative for the next 5 years due to the wider tariffs causing the average generation charge to breach the cap.

The adjustment tariff would decrease from the from 2022/23 at -£0.42/kW to -£3.54/kW in 2026/27 due to increase in the generation charging base increasing the wider tariffs. This causes the adjustment to go more negative to ensure charges are within the EU cap. For a full breakdown of the generation revenues, please see Table 24.

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 CPIH to the onshore substation tariffs set in RIIO-2. We have published the inflation indices in Table 21 on page 32.

Table 10 Local substation tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.148953	0.074480	0.051372
<1320 MW	Redundancy	0.313861	0.159415	0.113195
>=1320 MW	No redundancy	-	0.218821	0.155794
>=1320 MW	Redundancy	-	0.329287	0.236838

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 using the latest transport model, and for most existing users, the changes are minimal since the 2021/22 Final Tariffs (barring inflation). The 2022/23- 2026/27 Onshore local circuit tariffs are listed in below in Table 11.

Table 11 Onshore local circuit tariffs

Connection Point	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)
Aberarder			1.782229	1.817873	1.853660
Aberdeen Bay	2.638819	2.691595	2.745427	2.800335	2.855462
Achruach	4.345866	4.432689	- 2.691973	- 2.745967	- 2.800377
Aigas	0.676967	0.690506	0.704316	0.718403	0.732545
An Suidhe	3.081284	- 0.990374	- 1.009744	- 1.030092	- 1.050721
Arecleoch	2.149791	2.192787	1.293751	1.319626	1.345604
Armadale				3.216910	3.274506
Beaw Field				52.199538	53.651914
Beinneun Wind Farm	1.554100	1.585189	1.616873	1.649212	1.681681
Bhlaraidh Wind Farm	0.668298	0.681664	0.695297	0.709203	0.723164
Black Hill	1.571742	1.603176	1.635240	1.667945	1.700780
Black Law	1.808664	1.844837	1.881734	1.919369	1.957153
Blackcraig Wind Farm	6.515858	6.883018	7.020678	7.161092	7.302064
Blacklaw Extension	3.835506	3.912216	3.990460	4.070270	4.150396
Blarghour				3.051115	3.111178
Branxton		0.381219	0.388968	0.398268	0.407531
Chirmorie			0.978088	0.997649	1.017289
Clash Gour			0.106934	0.109735	0.111921
Clauchrie				0.837421	0.853906
Cloiche				1.474572	1.503600
Clyde (North)	0.113514	0.115784	0.118099	0.120461	0.122833

Connection Point	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)
Clyde (South)	0.131273	0.133898	0.136576	0.139308	0.142050
Corriegarth	2.998657	3.058631	3.119803	3.182199	3.244843
Corriemoillie	1.683828	1.717503	1.751853	1.786890	1.822065
Coryton	0.055835	0.056060	0.058251	0.059506	0.060960
Costa Head				5.168997	5.270753
Creag Riabhach	3.472130	3.541572	3.612404	3.684652	3.757187
Cruachan	1.846803	1.883818	1.921512	1.960021	1.998676
Culligran	1.793978	1.829858	1.866455	1.903784	1.941261
Deanie	2.947249	3.006194	3.066318	3.127645	3.189215
Dersalloch	2.493300	2.543166	2.594030	2.645910	2.697997
Dinorwig	2.428250	2.476815	2.526351	2.576878	2.627606
Dorenell	2.123975	4.936384	5.035112	5.135814	5.236917
Dumnaglass	1.173159	1.196622	1.220555	1.244966	1.269474
Dunhill	1.449613	1.478605	1.508177	1.538341	1.568625
Dunlaw Extension	1.529669	1.561087	1.600130	1.632275	1.665045
Edinbane	7.084899	7.226637	7.371304	7.518577	7.669146
Elchies				2.300117	2.345397
Energy Isles			56.644883	56.889095	58.433789
Enoch Hill		1.548074	1.579036	1.610617	1.642323
Ewe Hill	1.539418	1.570206	1.601610	1.633642	1.665802
Fallago	- 0.062644	- 0.063623	- 0.064775	- 0.065272	- 0.065850
Farr	3.608458	3.680628	3.754240	3.829325	3.904708
Fasque					3.081310
Faw Side				4.692271	4.785075
Fernoch	4.552786	4.643852	4.736733	4.831469	4.926585
Ffestiniogg	0.256053	0.261174	0.266398	0.271726	0.277075
Finlarig	0.331431	0.338059	0.344820	0.351717	0.358641
Foyers	0.296453	0.302382	0.308430	0.314599	0.320792
Galawhistle	3.621832	3.694268	3.768154	3.843517	3.919180
Gelnshero			1.864124	1.683727	1.716872
Gills Bay				2.704775	2.758021
Glen Kyllachy	- 0.473472	- 0.482942	0.492601	0.502453	0.512344
Glen Ullinish				7.566496	7.718008
Glendoe	1.903936	1.942015	1.980855	2.020472	2.060247
Glenglass	4.869625	4.967017	5.066358	5.167685	5.269415
Glenmuckloch			4.082166	4.163809	4.245777
Gordonbush	0.095519	0.123574	0.107169	0.159099	0.152870
Griffin Wind	9.827874	10.024048	10.224356	10.428813	10.633901
Hadyard Hill	2.864979	2.922278	2.980724	3.040339	3.100190
Hareshaw Rig					2.690489
Harestanes	2.617778	2.670852	2.724989	2.780204	2.835757
Hartlepool	0.090592	0.092743	0.094995	0.097496	0.099828
Hesta Head				9.400971	9.586037
Invergarry	0.378778	0.386353	0.394080	0.401962	0.409875
Kergord			43.802426	43.789789	45.076613
Kilgallioch	1.089364	1.111151	0.190483	0.194293	0.198117
Kilmorack	0.204420	0.208508	0.212679	0.216932	0.221203
Kinl			0.712943	0.475681	0.484852
Kype Muir	1.535278	1.565984	1.597303	1.629249	1.661323

Connection Point	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)
Langage	- 0.341485	- 0.348389	- 0.347164	- 0.353902	- 0.360741
Limekilns			0.656801	0.669937	0.683125
Lochay	0.378778	0.386353	0.394080	0.401962	0.409875
Luichart	0.580419	0.592026	0.603866	0.615943	0.628068
Marchwood	0.386307	0.394027	0.402301	0.410358	- 0.253840
Middle Muir	2.378409	2.425977	2.474497	2.523986	2.573673
Middleton	0.153594	0.157415	- 0.001558	0.000625	0.002016
Millennium South	0.488639	0.498394	0.508377	0.518544	0.529039
Millennium Wind	1.889856	1.927660	1.966193	2.005518	2.045002
Moffat	0.198335	0.203020	0.207801	0.212671	0.217680
Mossford	2.914057	2.972336	3.031782	3.092418	3.153294
Mossy Hill				47.139472	48.492237
Muaitheabhal				55.832102	56.930988
Nant	- 1.271073	- 1.296523	- 1.322465	1.402504	1.430112
Rhigos	0.106873	0.109057	0.112817	0.115087	0.117382
Rocksavage	0.018321	0.018687	0.019061	0.019442	- 0.019825
Sallachy				1.004905	1.024687
Saltend	0.017560	0.017912	- 0.002168	- 0.002212	- 0.002255
Sandy Knowe	5.181387	5.285015	5.786979	5.902719	6.018919
Scoop Hill				0.849323	0.867490
South Humber Bank	- 0.187664	- 0.191434	- 0.195266	- 0.199147	- 0.203052
Spalding	0.274675	0.280194	0.285918	0.292175	0.298669
Stornoway				50.472608	51.465988
Stranoch					1.739314
Strathbrora	- 0.025651	- 0.001934	- 0.019423	0.026331	0.018196
Strathy Wind	1.825321	1.882634	1.905142	2.228493	2.266631
Stronelairg	1.107047	1.130504	1.153001	0.958382	0.977249
Troston				0.837421	0.853906
Wester Dod	0.352211	0.170495	0.174007	0.177938	0.181837
Whitelee	0.109852	0.112049	0.114290	0.116576	0.118870
Whitelee Extension	0.305388	0.311496	0.317726	0.324080	0.330460

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 12 Circuits subject to one-off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
Farigaig 132kV	Corriegarth 132kV	4km Cable	4km OHL	Corriegarth
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes
Coalburn 132kV	Kype Muir 132kV	17km cable	17km OHL	Kype Muir
Coalburn 132kV	Middle Muir 132kV	13km cable	13km OHL	Middle Muir
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
East Kilbride South 275kV	Whitelee 275kV	6km of Cable	6km of OHL	Whitelee
East Kilbride South 275kV	Whitelee Extension 275kV	16.68km of Cable	16.68km of OHL	Whitelee Extension
Sandy Knowe 132kV	Glen Glass 132kV	7km of cable	7km of OHL	Sandy Knowe

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 licence of the associated OFTO.

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

Table 13 Offshore local tariffs 2022/23

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.981363	47.448077	1.178201
Burbo Bank	11.349149	21.934427	0.000000
Dudgeon	16.599924	26.045535	0.000000
Galloper	16.992267	26.875018	0.000000
Greater Gabbard	16.744314	38.718990	0.000000
Gunfleet	19.545355	18.024323	3.368849
Gwynt Y Mor	21.312321	21.071110	0.000000
Hornsea 1A	7.500569	26.538185	0.000000
Hornsea 1B	7.500569	26.538185	0.000000
Hornsea 1C	7.500569	26.538185	0.000000
Humber Gateway	12.542420	28.776625	0.000000
Lincs	17.411874	68.474947	0.000000
London Array	11.816070	40.512775	0.000000
Ormonde	27.613792	51.616163	0.411338
Race Bank	10.052457	27.920291	0.000000
Robin Rigg	-0.606088	34.402796	11.022437
Robin Rigg West	-0.606088	34.402796	11.022437
Sheringham Shoal	25.834847	30.427173	0.661397
Thanet	19.728152	36.960737	0.889775
Walney 1	23.849970	47.682154	0.000000
Walney 2	22.188899	45.156621	0.000000
Walney 3	10.325940	20.919735	0.000000
Walney 4	10.325940	20.919735	0.000000
West of Duddon Sands	9.234736	46.033950	0.000000
Westermost Rough	18.777289	31.956559	0.000000

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 2022/23, the methodology for demand tariffs remains unchanged. In our previous Five year-view published back in August 2020, demand tariffs were set to implement the demand residual banding charges from 2022/23. Ofgem have recently published a 'minded to position' delaying this until 2023/24. With the implementation of demand residual banded charges there will be changes to the demand tariffs, the existing non-locational element in demand tariffs (the demand residual tariff) will be replaced with a new pounds per site per year (pence per site per day) charge. 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 is, however the flooring / non-flooring of negative locational tariffs is subject to Ofgem's final decision.

In this report, we have calculated demand tariffs for 2023/24 – 2026/27 under the agreed distribution connected demand residual banded charges and have assumed flooring on negative locational demand tariffs (which will continue to apply on the triad HH demand and 4-7pm NHH demand) and the 4 band scenario for Transmission connected. However, this does not represent our view of the outcome of CMP343. For more information on the details of CMP343 please refer to the workgroup reports published on the ESO's website.[6]

Table 14 HH, NHH and EET Summary

HH Tariffs	2022/23	2023/24	2024/25	2025/26	2026/27
Average Tariff (£/kW)	51.39	1.87	1.60	1.61	1.84
Residual (£/kW)	53.29	-	-	-	-
EET	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Average Tariff (£/kW)	2.14	2.06	1.88	2.05	2.18
Phased residual (£/kW)	-	-	-	-	-
AGIC (£/kW)	2.32	2.36	2.41	2.46	2.51
Total Credit (£m)	13.98	13.70	12.70	12.68	14.97
NHH Tariffs	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
Average (p/kWh)	6.50	0.23	0.21	0.21	0.23

In Table 14 the impact of the change in methodology for demand charges can be seen, the switch to the demand residual charging bands in 2023/24 onwards, removes the demand residual element (total demand revenue less locational demand revenue) from HH and NHH tariffs and the average HH and NHH tariff becomes solely based on locational demand tariffs and the forecast revenue to be collected through the demand locational.

For 2023/24 onwards, we have used the agreed distribution connected bandings and unmetered demand for the demand residual tariffs. The banding scenario used in this forecast 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, as well as other potential methods being discussed in the CMP343 workgroup. We will incorporate the approved methodology in our future forecasts when the final decision is confirmed.

[6] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp343.

Table 15 Non-Locational demand residual banded charges

Band	Tariff	2022/23	2023/24	2024/25	2025/26	2026/27
Domestic	£/Site per Annum		31.02	30.58	29.46	29.60
LV_NoMIC_1			15.04	14.83	14.28	14.35
LV_NoMIC_2			76.79	75.71	72.92	73.29
LV_NoMIC_3			179.87	177.33	170.81	171.66
LV_NoMIC_4			536.47	528.91	509.44	511.99
LV1			1115.47	1099.75	1059.26	1064.56
LV2			1857.69	1831.51	1764.08	1772.91
LV3			2885.40	2844.74	2740.01	2753.72
LV4			6487.36	6395.93	6160.47	6191.30
HV1			4646.50	4581.02	4412.37	4434.45
HV2			16089.15	15862.41	15278.43	15354.89
HV3			31299.66	30858.56	29722.49	29871.24
HV4			77107.09	76020.42	73221.71	73588.14
EHV1			27071.26	26689.75	25707.16	25835.81
EHV2			161790.97	159510.85	153638.42	154407.30
EHV3			344891.66	340031.11	327512.77	329151.80
EHV4			927473.65	914402.76	880738.79	885146.42
T-Demand1			140682.30	138699.67	133593.40	134261.97
T-Demand2			499428.03	492389.59	474262.14	476635.58
T-Demand3			982479.21	968633.13	932972.65	937641.69
T-Demand4			2961464.19	2919728.27	2812237.73	2826311.49
Unmetered demand						
Unmetered	p/kWh		0.916177	0.903265	0.870011	0.874365
Demand Residual (£m)			**2,400.08**	**2,366.25**	**2,279.14**	**2,290.55**

8. Half-Hourly demand tariffs

The upcoming implementation of the demand residual charging bases via CMP343 will have a significant impact on the HH tariffs and the way in which HH customers are charged. As stated above, from 2023/24 the introduction of this new methodology will remove the current demand residual tariff from the HH tariff. The HH tariff (£/kW) will continue to be based on average demand taken over the triad periods but will only be reflective of the zonal locational demand tariffs. As such, the majority of the HH revenue would be collected through the new TDR methodology.

As per the overall demand charging methodology, the current HH demand tariffs will remain for 2022/23.

From 2023/24, the changes in the average locational HH tariffs remain consistent with the average locational tariff year on year. In 2023/24 (post TDR implementation) the average HH tariffs start at £1.87/kW, which then drops to £1.6/kW in 2024/25 but increasing back up to £1.84/kW in 2026/27 due to overall TNUoS revenue increase.

We have assumed in our base case that locational tariffs will be floored at £0/kW from 2023/24, although this is still subject to the outcome of CMP343 (a sensitivity has been provided to show the scenario of HH tariffs with locational tariffs not being floored). With locational tariffs being floored at £0/kW, demand zones 1 to 7 and zone 10 are set to £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 16 Gross Half-Hourly locational demand tariffs by demand zone*

Zone	Zone Name	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)
1	Northern Scotland	22.740255	-	-	-	-
2	Southern Scotland	31.470820	-	-	-	-
3	Northern	41.680268	-	-	-	-
4	North West	47.559033	-	-	-	-
5	Yorkshire	48.256053	-	-	-	-
6	N Wales & Mersey	48.884841	-	-	-	-
7	East Midlands	51.948679	-	-	-	-
8	Midlands	53.500361	1.183251	1.542582	1.307358	0.760787
9	Eastern	54.465861	-	-	-	-
10	South Wales	55.008036	4.227343	3.041558	3.065773	8.187153
11	South East	56.810225	2.362135	1.327500	1.400160	1.145258
12	London	59.948874	4.711316	3.578877	3.691459	3.573019
13	Southern	58.515282	4.945049	4.486189	4.577400	4.734708
14	South Western	60.445976	9.719020	9.750382	9.748246	11.400354

*2022/23 includes residual tariff of £53.29/kW

From 2023/24, 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 15 lists the demand residual tariffs for 2023/24 – 2026/27.

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

9. 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. There is no impact to the EET, through the implementation of the TCR demand residual charging banding methodology.

Table 17 shows the forecasted Embedded Export Tariffs by zone in the years 2022/23 to 2026/27.

Table 17 Embedded Export Tariffs 2022/23 to 2026/27

Zone	Zone Name	2022/23 (£/kW)	2023/24 (£/kW)	2024/25 (£/kW)	2025/26 (£/kW)	2026/27 (£/kW)
1	Northern Scotland	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-
3	Northern	-	-	-	-	-
4	North West	-	-	-	-	-
5	Yorkshire	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-
7	East Midlands	0.979490	1.129181	1.047299	1.057903	0.744994
8	Midlands	2.531172	3.545843	3.952426	3.765399	3.267217
9	Eastern	3.496672	2.123936	1.232163	1.325877	1.011117
10	South Wales	4.038846	6.589935	5.451402	5.523814	10.693583
11	South East	5.841035	4.724727	3.737344	3.858201	3.651688
12	London	8.979685	7.073908	5.988721	6.149500	6.079449
13	Southern	7.546093	7.307641	6.896033	7.035441	7.241138
14	South Western	9.476786	12.081612	12.160226	12.206287	13.906784
	These tariffs include:					
	Phased residual (£/kW)	-	-	-	-	-
	AGIC (£/kW)	2.316267	2.362592	2.409844	2.458041	2.506430

In this forecast, the key changes to the EET is the inflation of the AGIC which was reset as part of the RIIO-2 parameter refresh for 2021/22. The AGIC for 2022/23 is forecast (using forecast inflation) at £2.32/kW, a slight increase from 2021/22 by £0.04/kW. The fluctuation in the demand locational tariffs over the next 5 years will also play its part, as well the changes in the forecast of embedded export. 2022/23 The average EET is forecast at £2.14/kW, which is comparable with 2021/22 tariffs. Over the 5 years the average EET will decrease and in 2024/25 will reach a low of £1.88/kW, then increasing back up to £2.18/kW in 2026/27. The payments for EET move in line with the tariffs and increases in 2026/27 due to an increase in forecasted export in zones with higher tariffs.

The breakdown of the EET locational tariff into the peak and year-round components (the same values are used for HH tariff and EET, however EET is floored at £0/kW) can be found in Appendix C.

10. 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. For 2023/23, NHH demand users will continue to be subject to a p/kWh charge based on their consumption between 4pm-7pm every day of the year as they are currently. From 2023/24, the current methodology would only be applicable for the locational demand charges and NHH demand users also be subject to an additional £ per site per annum charge through the banded residual charges. For the demand residual tariffs for 2023/24 to 2026/27, please see Table 15.

Table 18 below shows what the tariffs would be for NHH for the next five years with the TDR being implemented in 2023/24. We have assumed that locational tariffs will be floored at £0/kW, although as stated above this is still subject to the outcome of CMP343.

Table 18 Non-half hourly demand tariffs from 2022/23 to 2026/27

Zone	Zone Name	2022/23 (p/kWh)	2023/24 (p/kWh)	2024/25 (p/kWh)	2025/26 (p/kWh)	2026/27 (p/kWh)
1	Northern Scotland	3.022811	-	-	-	-
2	Southern Scotland	4.012326	-	-	-	-
3	Northern	5.135737	-	-	-	-
4	North West	6.042024	-	-	-	-
5	Yorkshire	5.902938	-	-	-	-
6	N Wales & Mersey	5.982738	-	-	-	-
7	East Midlands	6.570820	-	-	-	-
8	Midlands	6.896029	0.152274	0.199008	0.168479	0.098127
9	Eastern	7.406702	-	-	-	-
10	South Wales	6.264584	0.480909	0.347672	0.350043	0.935237
11	South East	7.766608	0.322148	0.182401	0.192642	0.156505
12	London	6.256171	0.490426	0.376802	0.388562	0.372622
13	Southern	7.523025	0.634257	0.579943	0.591774	0.610218
14	South Western	8.444260	1.335608	1.358090	1.358419	1.591817

The average NHH tariff for 2022/23 is currently forecasted at 6.50p/kWh, which is roughly in line with the current year. The NHH tariffs will then drop with the implementation of the demand residual banded charges. From 2023/24 the average tariff will be 0.23p/kWh which will represent the locational demand charge relating to NHH. In our forecast this will then drop down to 0.21p/kW for 2024/25 - 2025/26 and then returns to 0.23p/kWh in 2026/27.

4

Overview of data input

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

11. 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
- Expansion Constant

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2022/23 period onwards, which can be found on the TEC register.[7] The contracted TEC volumes are based on the March 2021 TEC register.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. We forecast our best view of modelled TEC and use the TEC as published in the latest TEC register. For our November Draft Tariffs and January Final Tariffs we will use the TEC register as of 31st October 2021, in accordance with CUSC 14.15.6.

Chargeable TEC is our best view of the forecast volume of generation that will be connected to the system during 2022/23 and 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 2022.

Table 19 Generation contracted, modelled and chargeable TEC

Best View	2022/23	2023/24	2024/25	2025/26	2026/27
Contracted TEC (GW)	89.91	101.57	125.99	142.10	151.03
Modelled TEC (GW)	84.32	85.79	89.48	96.40	97.74
Chargeable TEC (GW)	74.93	73.51	72.09	78.96	80.35

12. 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 2022/23 onwards as stated in the interconnector register as of March 2021.

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

Table 20 Interconnectors

Interconnector	Node	Zone	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)	2026/27 (MW)
Aquind Interconnector	LOVE40	25			2,000	2,000	2,000
Auchencrosh (interconnector CCT)	AUCH20	10	660	660	660	660	660
Britned	GRAI40	24	1,200	1,200	1,200	1,200	1,200
Cronos	KEMS40	24				1,400	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	LEIS4A	18			1,600	1,600	1,600
FAB Link Interconnector	EXET40	26				1,400	1,400
Greenlink	PEMB40	20	504	504	504	504	504
Gridlink Interconnector	KINO40	24			1,500	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	750
Nemo Link	RICH40	24	1,020	1,020	1,020	1,020	1,020
NeuConnect Interconnector	GRAI40	24		1,400	1,400	1,400	1,400
NorthConnect	PEHE20	2					1,400
NS Link	BLYT4A	13	1,400	1,400	1,400	1,400	1,400
Tarchon	CORI10	1		0	0	0	1,400
Viking Link Denmark Interconnector	BICF4A	17		1,500	1,500	1,500	1,500

13. 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. With the approval of CMP353 the current EC value is based on the RIIO-1 value set back in 2013/14 and will continue to increase in-line with inflation (switched from RPI to CPIH in 2021/22). A review on the methodology of the EC and the expansion factors is ongoing with the industry. Please see the EC values used in this 5-year view.

Table 21 Expansion Constant

£/MWkm		2022/23	2023/24	2024/25	2025/26	2026/27
Expansion Constant		15.276497	15.582027	15.893667	16.211541	16.530678
	2018/19	2022/23	2023/24	2024/25	2025/26	2026/27
Base Revenue Inflation indices	1.000000	1.068271	1.087212	1.108208	1.130353	1.152960

14. Locational onshore security factor

The locational onshore security factor (also called the global security factor), currently at 1.76, is applied to locational tariffs, and approximately represent the redundant network capacity to secure energy flows under network contingencies. This parameter has been reviewed last year and will be fixed for the RIIO-2 duration.

15. 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 CPIH (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-2 inflated by CPIH.

16. Offshore local tariffs

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

17. Allowed revenues

The majority of the TNUoS charges 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 total TNUoS revenue is forecast to increase steadily throughout the next 5 year. This is mainly driven by offshore TOs revenue increase as more OFTO being connected. Whilst the onshore TOs revenue is forecast a downward trend based on the final decision on their RIIO-2 business plan.
For onshore TOs, the allowed revenues have been based on TOs forecast reflecting Ofgem's final determination on their RIIO-2 parameters including project spending profiles, rate of return and inflation index. The 2022/23 revenue figures will be updated by November Draft tariffs and finalised by January 2022 in the Final tariffs.

The three onshore TOs have appealed to CMA against Ofgem on their RIIO-T2 determination, and challenged a few parameters including cost of equity and outperformance wedge. CMA will make a decision on the appeals by 30th October 2021. As a result, onshore TOs may update their revenue forecast according to the timetable as specified under the STC (SO-TO code), and we will then include the updated revenue figures in our TNUoS forecast.

For more details on TNUoS revenue breakdown, please refer to Appendix G. We are currently working with onshore TOs to update the revenue data template in STC, to enable onshore TOs to provide revenue breakdown under RIIO-T2 licence.

Table 22 Allowed revenues

Allowed Revenues £m Nominal	2022/23	2023/24	2024/25	2025/26	2026/27
National Grid Electricity Transmission					
Income from TNUoS	**1,764.5**	**1,704.4**	**1,674.6**	**1,645.0**	**1,645.0**
Scottish Power Transmission					
Income from TNUoS	**348.7**	**370.9**	**361.6**	**337.6**	**337.6**
SHE Transmission					
Income from TNUoS	**632.7**	**582.9**	**586.7**	**563.4**	**563.4**
National Grid Electricity System Operator					
Pass-through from TNUoS	67.3	67.3	67.4	67.5	67.5
Offshore (+ Interconnector cap&floor)	552.85	656.45	757.06	876.37	936.73
Total to Collect from TNUoS	**3,366.0**	**3,382.1**	**3,447.4**	**3,489.8**	**3,550.2**

Please note these figures are rounded to one decimal place.

18. Generation / Demand (G/D) Split

The revenue to be collected from generators and demand suppliers for 2022/23 will be updated throughout quarterly tariff forecasts and will be finalised in the Final Tariffs.

The G/D split forecast is shown in Table 24. In this forecast, we assume CMP368/369 is in the baseline forecast and have attempted to assess the likely revenue associated with pre-existing transmission assets, based on our preliminary understanding of the concept, and the data available so far. This forecast is subject to further potential methodology changes, and alternative options may be developed by the workgroup.

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”.

TNUoS generation residual (TGR) change

CUSC modification proposals CMP317/327 was approved in December 2020 and was included in the 2021/22 final tariffs. Under CMP317/327, charges that are collected via generator local tariffs (including onshore and offshore local substation charges, and onshore and offshore local circuit charges) were excluded from the EU gen cap. Therefore, the EU gen cap is only applicable for charges that are collected via generation wider tariffs.

When approving CMP317/327, Ofgem also directed the ESO to raise a CUSC mod, to update charges for the physical assets required for connection, generation output and Generator charges for the purpose of maintaining compliance with the limiting regulation (the [0 ~ €2.50]/MWh range). The ESO has raised this CUSC mod (CMP368/369)[8], and options will be developed by the workgroup. In this forecast, we have revised the DCLF-ICRP model to accommodate proposed changes under CMP368/389. based on our preliminary understanding of the original proposal and available data.

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 €1.13/£ across years 2022/23 to 2025/26.

Generation Output

The forecast output of generation was based on FES (Future Energy scenarios) 2020 publication and is the average of the five scenarios (four FES scenarios, plus FES five-year forecast). For year 2022/23 tariff forecast, the generation output figure will be updated following FES 2021.

Error Margin

The error margin has remained unchanged at 20.8% and will be updated in the August publication following outturn of 2021/22 data.

Table 23 shows the error margin calculation, based on the last five full years’ generation revenue and generation TWh output variance figures.

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

Table 23 Error Margin Calculation

Calculation for	2022/23		
	Revenue inputs		Generation output variance
Data from year:	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%
2020/21			
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 maximum of the (absolute) values in the series

In summary, the parameters used to calculate the proportions of revenue collected from generation and demand are shown in table 24.

Table 24 Generation and demand revenue proportions

		2022/23	2023/24	2024/25	2025/26	2026/27
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50	2.50	2.50
y	Error Margin	0.21	0.21	0.21	0.21	0.21
ER	Exchange Rate (€/£)	1.13	1.13	1.13	1.13	1.13
MAR	Total Revenue (£m)	3,366.00	3,382.06	3,447.37	3,489.77	3,550.19
GO	Generation Output (TWh)	209.96	206.55	207.91	213.95	213.95
G	% of revenue from generation	24.8%	26.7%	29.7%	33.0%	33.6%
D	% of revenue from demand	75.2%	73.3%	70.3%	67.0%	66.4%
G.MAR	Revenue recovered from generation (£m)	836.17	904.33	1,023.08	1,152.16	1,193.00
D.MAR	Revenue recovered from demand (£m)	2,529.84	2,477.74	2,424.29	2,337.61	2,357.19
Breakdown of generation revenue						
	Revenue from the Peak element	138.22	109.30	98.61	82.16	66.98
	Revenue from the Year Round Shared element	108.40	130.14	125.09	151.62	179.95
	Revenue from the Year Round Not Shared eleme	143.28	137.40	187.62	314.41	386.47
	Revenue from Onshore Local Circuit tariffs	16.11	17.31	38.51	67.31	71.17
	Revenue from Onshore Local Substation tariffs	10.48	11.06	11.74	12.76	14.25
	Revenue from Offshore Local tariffs	451.03	523.14	618.79	722.28	758.42
	Revenue from the adjustment element	- 31.35	- 24.00	- 57.29	- 198.38	- 284.24
G.MAR	Total Revenue recovered from generation (£m)	836.17	904.33	1,023.08	1,152.16	1,193.00
	Revenue from large embedded generation (£m)	7.09	7.50	9.18	9.11	9.30
	Revenue from local charges associated with pre-existing assets (indicative) (£m)	1.94	2.10	3.69	18.42	19.27

19. Charging bases for 2022/23- 2026/27

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 74.9GW for 2022/23 and increase up to 80GW by 2025/26 (see table 19).

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated for 2022/23 and for the subsequent 4 years (up to 2026/27).

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 2021)
- 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 continues to be tracked and mainly factored in demand forecast for 2022/23.

Table 25 Demand charging bases

	2022/23	2023/24	2024/25	2025/26	2026/27
Average System Demand at Triad (GW)	49.83	49.75	49.79	49.78	49.89
Average HH Metered Demand at Triad (GW)	19.07	19.03	19.16	19.10	19.14
Chargeable Export Volume (GW)	6.54	6.66	6.76	6.18	6.85
NHH Annual Energy between 4pm and 7pm (TWh)	24.18	24.21	24.00	24.05	24.18

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2021/22 ALFs, based upon data from 2015/16 to 2019/20. 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.[9]

The ALFs that will apply to 2022/23 TNUoS Tariffs will be updated and included in the Draft tariffs in November 2021.

21. Generation adjustment and demand residuals

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

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

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

Where

- A_G is the generation adjustment tariff (£/kW)

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

- 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 took effect from April 2021 for the Transmission Generation Residual (TGR).

Subsequently CMP317/327 was raised to implement the TCR decision. Under CMP317/327, generation residual has been removed but to ensure compliance with the EU cap within the range of €0-2.50/MWh, an adjustment mechanism has been introduced. It has confirmed that all local onshore and local offshore tariffs are not included in the EU cap, i.e. removing these from the definition of 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

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

Where:

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

Z_G, Z_D, and EE are determined by the locational elements of tariffs. The EE is also affected by the value of the AGIC[10] and phased residual.

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

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

Demand customers will continue paying the locational elements of demand tariffs, based on their triad demand for HH demand or their aggregated annual consumption during 4-7pm each day for their NHH demand. 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 from 2023/24.

[10] Avoided Grid Supply Point Infrastructure Credit

Table 26 Residual components calculation

Component		2022/23	2023/24	2024/25	2025/26	2026/27
G	Proportion of revenue recovered from generation (%)	24.8%	26.7%	29.7%	33.0%	33.6%
D	Proportion of revenue recovered from demand (%)	75.2%	73.3%	70.3%	67.0%	66.4%
R	Total TNUoS revenue (£m)	3,366.0	3,382.1	3,447.4	3,489.8	3,550.2
Generation Residual						
RG	Generator adjustment tariff (£/kW)	- 0.42	- 0.33	- 0.79	- 2.51	- 3.54
ZG	Revenue recovered from the locational element of generator tariffs (£m)	389.9	376.8	411.3	548.2	633.4
O	Revenue recovered from offshore local tariffs (£m)	451.0	523.1	618.8	722.3	758.4
LG	Revenue recovered from onshore local substation tariffs (£m)	10.5	11.1	11.7	12.8	14.3
SG	Revenue recovered from onshore local circuit tariffs (£m)	16.1	17.3	38.5	67.3	71.2
BG	Generator charging base (GW)	74.9	73.5	72.1	79.0	80.3
Gross Demand Residual						
RD (tariff)	Demand residual tariff (£/kW)	53.14				
RD	Demand residual (£m)	2,648.2	2,400.1	2,357.1	2,270.0	2,281.2
ZD (Unfloored)	Revenue recovered from the locational element of demand tariffs (£m)	- 104.4	- 111.9	- 113.6	- 128.6	- 141.6
ZD (Floored)	Revenue recovered from the locational element of demand tariffs (£m)		91.4	79.9	80.3	90.9
EE	Amount to be paid to Embedded Export Tariffs (£m)	14.0	13.7	12.7	12.7	15.0
BD	Demand Gross charging base (GW)	49.8	49.7	49.8	49.8	49.9

5

Sensitivity Analysis

Purpose

We are conscious that there are uncertainties with the charging methodologies over the next 5 years. 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. 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 / charges that reflect a few of the options that are being assessed by the workgroups.

We have also included some sensitivities around connecting new interconnectors after receiving requests for this in our Charging Forum in February 2021.

The sensitivity analysis that we undertook for 2022/23-2026/27 tariffs include -

1. A scenario where Gridlink interconnector does not connect in 2024/25
2. A scenario where Eurolink interconnector does not connect in 2024/25
3. A scenario where we have different T-connected bandings for TDR
4. A scenario where the demand location tariffs are not floored when the TDR is implemented

Caveats

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.

22. Impact of new interconnectors

In our last Charging Forum, held in February 2021, it was requested that we provide some sensitivities to demonstrate what impact the interconnectors may have on the tariffs. We have chosen two interconnectors that are due to connect in 2024/25 according to the published Interconnector Register to demonstrate the impact on TNUoS tariffs. These interconnectors are:

- Gridlink interconnector connecting in generation zone 24 with 1500MW import capacity
- Eurolink interconnector connecting in generation zone 18 with 1600MW import capacity

The impact of interconnectors is included in the modelled TEC only and are excluded from the chargeable TEC, as interconnectors are not liable for TNUoS charges. Due to this, the impact of interconnectors is only used in modelling the incremental costs to the network to calculate the locational tariffs.

The impact of connecting Gridlink in generation zone 24 and Eurolink in generation zone 18 is broadly the same. There is a shift from generation year round not shared tariffs to year round shared tariffs. The generation peak tariffs increase in the majority of zones except zones 22 to 26, where there is a lot of demand. The increase is mainly driven by the fact interconnectors are modelled as year round TEC and a large year round generator in the south will offset the north-south year round flow. This causes weaker loading on some year round circuits causing them to become classified as peak circuits. This is turn increases the peak tariffs.

The increase in generation revenue (£0.11m) then causes the demand residual tariffs to decrease. The locational demand tariffs also decrease in the south, as the added import offsets the demand, decreasing the need for additional reinforcements for demand.

Table S1 Impact of connecting Gridlink on 2024/25 Generation Tariffs

Generation Tariffs		2024/25 excluding Gridlink				2024/25 Base case including Gridlink				Change in tariffs by including Gridlink			
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round (£/kW)	Adjustment Tariff (£/kW)	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round (£/kW)	Adjustment Tariff (£/kW)	Change in System Peak (£/kW)	Change in Shared Year (£/kW)	Change in Not Shared Year (£/kW)	Change in Adjustment (£/kW)
1	North Scotland	3.161767	16.086402	18.722166	-0.815932	3.228161	15.922323	18.664738	-0.794656	0.066394	-0.164079	-0.057428	0.021276
2	East Aberdeenshire	4.185079	8.247195	18.722166	-0.815932	4.250525	8.142102	18.664738	-0.794656	0.065446	-0.105093	-0.057428	0.021276
3	Western Highlands	2.928811	15.204756	18.061935	-0.815932	2.997512	15.037159	18.001873	-0.794656	0.068701	-0.167597	-0.060062	0.021276
4	Skye and Lochalsh	-1.748862	15.204756	19.965970	-0.815932	-1.680886	15.037159	19.912713	-0.794656	0.067976	-0.167597	-0.053257	0.021276
5	Eastern Grampian and Tayside	4.163166	13.888773	16.785197	-0.815932	4.387196	13.717591	16.721655	-0.794656	0.224030	-0.171182	-0.063542	0.021276
6	Central Grampian	3.768045	12.602691	15.224371	-0.815932	4.388060	12.198590	14.878152	-0.794656	0.620015	-0.404101	-0.346219	0.021276
7	Argyll	2.460362	10.519804	20.648837	-0.815932	3.619144	10.347591	19.779364	-0.794656	1.158782	-0.172213	-0.869473	0.021276
8	The Trossachs	3.389702	10.519804	12.651836	-0.815932	3.564477	10.347591	12.592019	-0.794656	0.174775	-0.172213	-0.059817	0.021276
9	Stirlingshire and Fife	2.436418	9.685183	11.899408	-0.815932	2.479158	9.551003	11.873878	-0.794656	0.042740	-0.134180	-0.025530	0.021276
10	South West Scotlands	1.663145	9.884783	12.062895	-0.815932	1.736632	9.731310	12.021562	-0.794656	0.073487	-0.153473	-0.041333	0.021276
11	Lothian and Borders	3.319087	9.884783	7.181799	-0.815932	3.374947	9.731310	7.170162	-0.794656	0.055860	-0.153473	-0.011637	0.021276
12	Solway and Cheviot	1.233697	6.759158	6.304759	-0.815932	1.302351	6.614974	6.280539	-0.794656	0.068654	-0.144184	-0.024220	0.021276
13	North East England	3.307376	5.777514	4.414310	-0.815932	3.356563	5.652913	4.427803	-0.794656	0.049187	-0.124601	0.013493	0.021276
14	North Lancashire and The Lakes	1.179782	5.777514	0.396937	-0.815932	1.255895	5.652913	0.348719	-0.794656	0.076113	-0.124601	-0.048218	0.021276
15	South Lancashire, Yorkshire and Humber	4.092066	2.371723	0.805813	-0.815932	4.130216	2.265403	0.838674	-0.794656	0.038150	-0.106320	0.032861	0.021276
16	North Midlands and North Wales	3.330793	0.507538	-	-0.815932	3.367914	0.325194	-	-0.794656	0.037121	-0.182344	-	0.021276
17	South Lincolnshire and North Norfolk	3.564177	2.897710	-	-0.815932	3.593202	2.819282	-	-0.794656	0.029025	-0.078428	-	0.021276
18	Mid Wales and The Midlands	0.481932	5.343550	-	-0.815932	0.578087	5.318168	-	-0.794656	0.096155	-0.025382	-	0.021276
19	Anglesey and Snowdon	5.850288	-0.312006	-	-0.815932	5.922122	-0.516703	-	-0.794656	0.071834	-0.204697	-	0.021276
20	Pembrokeshire	7.841154	-6.431786	-	-0.815932	7.810953	-6.402058	-	-0.794656	-0.030201	0.029728	-	0.021276
21	South Wales & Gloucester	2.920793	-7.091065	-	-0.815932	2.887311	-7.011841	-	-0.794656	-0.033482	0.079224	-	0.021276
22	Cotswold	1.540515	5.390403	-12.424830	-0.815932	1.504294	5.515635	-12.517820	-0.794656	-0.036221	0.125232	-0.092990	0.021276
23	Central London	-3.601749	5.390403	-6.288006	-0.815932	-3.646896	5.515635	-6.278502	-0.794656	-0.045147	0.125232	0.009504	0.021276
24	Essex and Kent	-2.768663	5.390403	-	-0.815932	-2.755642	5.515635	-	-0.794656	0.013021	0.125232	-	0.021276
25	Oxfordshire, Surrey and Sussex	-0.370227	-0.823485	-	-0.815932	-0.433405	-0.690925	-	-0.794656	-0.063178	0.132560	-	0.021276
26	Somerset and Wessex	-1.799169	-1.563207	-	-0.815932	-1.843181	-1.451260	-	-0.794656	-0.044012	0.111947	-	0.021276
27	West Devon and Cornwall	-2.337654	-9.676275	-	-0.815932	-2.376864	-9.597891	-	-0.794656	-0.039210	0.078384	-	0.021276

Table S2 Impact of connecting Gridlink on 2024/25 Demand Tariffs

Zone No.	Zone Name	2024/25 excluding Gridlink			2024/25 base case including Gridlink			Change in tariffs		
		HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)	HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)	HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-	-	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-	-	-	-	-
3	Northern	-	-	-	-	-	-	-	-	-
4	North West	-	-	-	-	-	-	-	-	-
5	Yorkshire	-	-	-	-	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-	-	-	-	-
7	East Midlands	-	-	1.044328	-	-	1.047299	-	-	0.002971
8	Midlands	1.455473	0.187770	3.865317	1.542582	0.199008	3.952426	0.087109	0.011238	0.087109
9	Eastern	-	-	1.224688	-	-	1.232163	-	-	0.007475
10	South Wales	3.044720	0.348033	5.454564	3.041558	0.347672	5.451402	-0.003162	-0.000361	-0.003162
11	South East	1.455937	0.200048	3.865781	1.327500	0.182401	3.737344	-0.128437	-0.017647	-0.128437
12	London	3.684286	0.387900	6.094130	3.578877	0.376802	5.988721	-0.105409	-0.011098	-0.105409
13	Southern	4.531606	0.585814	6.941450	4.486189	0.579943	6.896033	-0.045417	-0.005871	-0.045417
14	South Western	9.772649	1.361192	12.182493	9.750382	1.358090	12.160226	-0.022267	-0.003102	-0.022267

Table S3 Impact of connecting Gridlink on 2024/25 TDR Bandings

TDR Band	2024/25 excluding Gridlink TDR Tariff (£/site)	2024/25 base case including Gridlink TDR Tariff (£/site)	Change
Domestic	30.57	30.58	0.01
LV_NoMIC_1	14.82	14.83	0.00
LV_NoMIC_2	75.69	75.71	0.02
LV_NoMIC_3	177.28	177.33	0.05
LV_NoMIC_4	528.75	528.91	0.16
LV1	1099.42	1099.75	0.33
LV2	1830.96	1831.51	0.54
LV3	2843.90	2844.74	0.84
LV4	6394.04	6395.93	1.89
HV1	4579.66	4581.02	1.35
HV2	15857.72	15862.41	4.69
HV3	30849.44	30858.56	9.12
HV4	75997.95	76020.42	22.47
EHV1	26681.86	26689.75	7.89
EHV2	159463.70	159510.85	47.15
EHV3	339930.60	340031.11	100.50
EHV4	914132.50	914402.76	270.27
T-Demand1	138658.67	138699.67	41.00
T-Demand2	492244.06	492389.59	145.53
T-Demand3	968346.83	968633.13	286.30
T-Demand4	2918865.30	2919728.27	862.98
Unmetered demand		**p/kWh per year**	
Unmetered	0.902998	0.903265	0.000267

Table S4 Impact of connecting Eurolink on 2024/25 Generation Tariffs

Generation Tariffs		2024/25 excluding Eurolink				2024/25 Base case including Eurolink				Change in tariffs			
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round (£/kW)	Adjustment Tariff (£/kW)	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round (£/kW)	Adjustment Tariff (£/kW)	Change in System Peak (£/kW)	Change in Shared Year (£/kW)	Change in Not Shared Year (£/kW)	Change in Adjustment (£/kW)
1	North Scotland	3.200580	16.051541	18.739424	-0.799146	3.228161	15.922323	18.664738	-0.794656	0.027581	-0.129218	-0.074686	0.004490
2	East Aberdeenshire	4.224174	8.208320	18.739424	-0.799146	4.250525	8.142102	18.664738	-0.794656	0.026351	-0.066218	-0.074686	0.004490
3	Western Highlands	2.967460	15.170192	18.079416	-0.799146	2.997512	15.037159	18.001873	-0.794656	0.030052	-0.133033	-0.077543	0.004490
4	Skye and Lochalsh	-1.710227	15.170192	19.983017	-0.799146	-1.680886	15.037159	19.912713	-0.794656	0.029341	-0.133033	-0.070304	0.004490
5	Eastern Grampian and Tayside	4.201218	13.852988	16.801492	-0.799146	4.387196	13.717591	16.721655	-0.794656	0.185978	-0.135397	-0.079837	0.004490
6	Central Grampian	3.804123	12.568190	15.242225	-0.799146	4.388060	12.198590	14.878152	-0.794656	0.583937	-0.369600	-0.364073	0.004490
7	Argyll	2.494495	10.486590	20.667547	-0.799146	3.619144	10.347591	19.779364	-0.794656	1.124649	-0.138999	-0.888183	0.004490
8	The Trossachs	3.425001	10.486590	12.671280	-0.799146	3.564477	10.347591	12.592019	-0.794656	0.139476	-0.138999	-0.079261	0.004490
9	Stirlingshire and Fife	2.477817	9.647410	11.914742	-0.799146	2.479158	9.551003	11.873878	-0.794656	0.001341	-0.096407	-0.040864	0.004490
10	South West Scotlands	1.693189	9.851834	12.082180	-0.799146	1.736632	9.731310	12.021562	-0.794656	0.043443	-0.120524	-0.060618	0.004490
11	Lothian and Borders	3.372706	9.851834	7.187891	-0.799146	3.374947	9.731310	7.170162	-0.794656	0.002241	-0.120524	-0.017729	0.004490
12	Solway and Cheviot	1.259827	6.726668	6.324890	-0.799146	1.302351	6.614974	6.280539	-0.794656	0.042524	-0.111694	-0.044351	0.004490
13	North East England	3.397576	5.727065	4.399855	-0.799146	3.356563	5.652913	4.427803	-0.794656	-0.041013	-0.074152	0.027948	0.004490
14	North Lancashire and The Lakes	1.184495	5.727065	0.466246	-0.799146	1.255895	5.652913	0.348719	-0.794656	0.071400	-0.074152	-0.117527	0.004490
15	South Lancashire, Yorkshire and Humber	4.206690	2.306993	0.776225	-0.799146	4.130216	2.265403	0.838674	-0.794656	-0.076474	-0.041590	0.062449	0.004490
16	North Midlands and North Wales	3.370536	0.511254	-	-0.799146	3.367914	0.325194	-	-0.794656	-0.002622	-0.186060	-	0.004490
17	South Lincolnshire and North Norfolk	3.608342	2.742345	-	-0.799146	3.593202	2.819282	-	-0.794656	-0.015140	0.076937	-	0.004490
18	Mid Wales and The Midlands	0.605006	4.714939	-	-0.799146	0.578087	5.318168	-	-0.794656	-0.026919	0.603229	-	0.004490
19	Anglesey and Snowdon	5.801142	-0.255437	-	-0.799146	5.922122	-0.516703	-	-0.794656	0.120980	-0.261266	-	0.004490
20	Pembrokeshire	7.796151	-6.389663	-	-0.799146	7.810953	-6.402058	-	-0.794656	0.014802	-0.012395	-	0.004490
21	South Wales & Gloucester	2.874808	-7.048906	-	-0.799146	2.887311	-7.011841	-	-0.794656	0.012503	0.037065	-	0.004490
22	Cotswold	1.493785	5.435567	-12.421586	-0.799146	1.504294	5.515635	-12.517820	-0.794656	0.010509	0.080068	-0.096234	0.004490
23	Central London	-3.644958	5.435567	-6.266867	-0.799146	-3.646896	5.515635	-6.278502	-0.794656	-0.001938	0.080068	-0.011635	0.004490
24	Essex and Kent	-2.765303	5.435567	-	-0.799146	-2.755642	5.515635	-	-0.794656	0.009661	0.080068	-	0.004490
25	Oxfordshire, Surrey and Sussex	-0.426511	-0.755577	-	-0.799146	-0.433405	-0.690925	-	-0.794656	-0.006894	0.064652	-	0.004490
26	Somerset and Wessex	-1.847067	-1.494579	-	-0.799146	-1.843181	-1.451260	-	-0.794656	0.003886	0.043319	-	0.004490
27	West Devon and Cornwall	-2.384905	-9.622031	-	-0.799146	-2.376864	-9.597891	-	-0.794656	0.008041	0.024140	-	0.004490

Table S5 Impact of connecting Eurolink on 2024/25 Demand Tariffs

Zone No.	Zone Name	2024/25 excluding Eurolink			2024/25 base case including Eurolink			Change in tariffs		
		HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)	HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)	HH Gross Demand Zonal Locational Tariff (£/kW)	NHH Demand Zonal Locational Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	-	-	-	-	-	-	-	-	-
2	Southern Scotland	-	-	-	-	-	-	-	-	-
3	Northern	-	-	-	-	-	-	-	-	-
4	North West	-	-	-	-	-	-	-	-	-
5	Yorkshire	-	-	-	-	-	-	-	-	-
6	N Wales & Mersey	-	-	-	-	-	-	-	-	-
7	East Midlands	-	-	1.061270	-	-	1.047299	-	-	- 0.013971
8	Midlands	1.455122	0.187725	3.864966	1.542582	0.199008	3.952426	0.087460	0.011283	0.087460
9	Eastern	-	-	1.331031	-	-	1.232163	-	-	- 0.098868
10	South Wales	3.046687	0.348258	5.456531	3.041558	0.347672	5.451402	- 0.005129	- 0.000586	- 0.005129
11	South East	1.388413	0.190770	3.798257	1.327500	0.182401	3.737344	- 0.060913	- 0.008369	- 0.060913
12	London	3.652186	0.384520	6.062030	3.578877	0.376802	5.988721	- 0.073309	- 0.007718	- 0.073309
13	Southern	4.523895	0.584817	6.933739	4.486189	0.579943	6.896033	- 0.037706	- 0.004874	- 0.037706
14	South Western	9.767688	1.360501	12.177532	9.750382	1.358090	12.160226	- 0.017306	- 0.002411	- 0.017306

Table S6 Impact of connecting Eurolink on 2024/25 TDR Bandings

TDR Band	2024/25 base case including Eurolink TDR Tariff (£/site)	2024/25 excluding Eurolink TDR Tariff (£/site)	Change
Domestic	30.58	30.58	0.00
LV_NoMIC_1	14.83	14.83	0.00
LV_NoMIC_2	75.71	75.70	-0.01
LV_NoMIC_3	177.33	177.32	-0.02
LV_NoMIC_4	528.91	528.86	-0.05
LV1	1099.75	1099.65	-0.10
LV2	1831.51	1831.34	-0.17
LV3	2844.74	2844.48	-0.26
LV4	6395.93	6395.36	-0.58
HV1	4581.02	4580.60	-0.41
HV2	15862.41	15860.98	-1.43
HV3	30858.56	30855.77	-2.79
HV4	76020.42	76013.54	-6.88
EHV1	26689.75	26687.33	-2.41
EHV2	159510.85	159496.42	-14.43
EHV3	340031.11	340000.35	-30.76
EHV4	914402.76	914320.06	-82.71
T-Demand1	138699.67	138687.12	-12.55
T-Demand2	492389.59	492345.06	-44.54
T-Demand3	968633.13	968545.52	-87.61
T-Demand4	2919728.27	2919464.19	-264.08
Unmetered demand		**p/kWh per year**	
Unmetered	0.903265	0.903183	-0.000082

23. TDR Sensitivities

Given that there is still a level of uncertainty around the final position for some elements of the implementation of the TDR.. In addition to the assumption we have applied to the base case, we are providing further analysis of other options, in line with customers feedback and requests that we have been receiving.

In this sensitivity we have provided an overview of the impact of:

- Unfloored locational tariffs scenario
- 4 Transmission connected banding scenarios (including the impact of floored & unfloored locational tariffs)
    - 1 band – No split
    - 2 band – site consumption (MWh) percentile split <=85% / >85%
    - 4 band – site consumption (MWh) percentile split <=40% / <=70% / <=85% / >85% (used in base case)
    - 2 band – Voltage split <=132kV / >132kV

These scenarios are developed for 2023/24 to illustrate the potential impact.

Unfloored locational tariffs

We have produced the HH and NHH locational tariffs in the unfloored scenario and compared against the tariffs under floored scenario (as per the base case). Please see Table S6 for details.

We have also provided the analysis on the demand residual banded charges under the unfloored scenario as per Table S7. The demand residual value increases due to the negative revenue recovery for through the locational tariffs. This subsequently increases the demand residual by roughly £200m (8%) which in turn increases the band charges by the same proportion.

In the floored scenario, the total demand revenue is £91.4m with £35.6m for HH and £55.7m for NHH. In the scenario of tariffs being unfloored, the total revenue is £-111.9m (-£39.4m for HH and -£72.5m NHH).

We are aware that there were other scenarios considered by the CMP343workgroup. There was a view that rather than a GB-wide charge across each band, there would be 'regional' charges for each band. Please refer the workgroup report for further insight.

Table S7 Unfloored tariffs for demand locational tariffs for 2023/24

		HH		NHH	
Zone	Zone Name	Floored (£/kW)	Unfloored (£/kW)	Floored (p/kWh)	Unfloored (p/kWh)
1	Northern Scotland	-	- 30.675279	-	- 4.084160
2	Southern Scotland	-	- 21.912795	-	- 2.788139
3	Northern	-	- 11.943236	-	- 1.469239
4	North West	-	- 5.710426	-	- 0.726413
5	Yorkshire	-	- 4.882721	-	- 0.598099
6	N Wales & Mersey	-	- 4.029323	-	- 0.493468
7	East Midlands	-	- 1.233411	-	- 0.155795
8	Midlands	1.183251	1.183251	0.152274	0.152274
9	Eastern	-	- 0.238656	-	- 0.032322
10	South Wales	4.227343	4.227343	0.480909	0.480909
11	South East	2.362135	2.362135	0.322148	0.322148
12	London	4.711316	4.711316	0.490426	0.490426
13	Southern	4.945049	4.945049	0.634257	0.634257
14	South Western	9.719020	9.719020	1.335608	1.335608
Revenue Recovery (£m)		35.63	-39.39	55.74	-72.49

Table S8 Demand Residual Banded Charges for 2023/24 under Transmission connected banding scenarios

		Band	Floored £/site	Unfloored £/site		
		Domestic	31.02	33.65		
		LV_NoMIC_1	15.04	16.31		
		LV_NoMIC_2	76.79	83.30		
		LV_NoMIC_3	179.87	195.10		
		LV_NoMIC_4	536.47	581.90		
		LV1	1,115.47	1,209.92		
		LV2	1,857.69	2,015.00		
		LV3	2,885.40	3,129.74		
		LV4	6,487.36	7,036.72		
		HV1	4,646.50	5,039.97		
		HV2	16,089.15	17,451.60		
		HV3	31,299.66	33,950.15		
		HV4	77,107.09	83,636.60		
		EHV1	27,071.26	29,363.69		
		EHV2	161,790.97	175,491.61		
		EHV3	344,891.66	374,097.48		
		EHV4	927,473.65	1,006,013.16		
		Band (Percentiles/Volatge)	**Floored £/site**	**Unfloored £/site**	**Thresholds (MWh) Lower**	**Thresholds (MWh) Upper**
Transmission Connected	1 Band	T-Demand1 (No Split)	782,285.17	848,529.96		
Transmission Connected	2 Bands (MWh)	T-Demand1 (<=85%)	412,235.91	447,144.51	-	139,931
Transmission Connected	2 Bands (MWh)	T-Demand2 (>85%)	2,961,464.19	3,212,244.29	139,932	∞
Transmission Connected	4 Bands (MWh)	T-Demand1 (<=40%)	140,682.30	152,595.44	-	31,177
Transmission Connected	4 Bands (MWh)	T-Demand2 (>40% <=70%)	499,428.03	541,720.16	31,178	83,801
Transmission Connected	4 Bands (MWh)	T-Demand3 (>70% <=85%)	982,479.21	1,065,676.65	83,802	139,931
Transmission Connected	4 Bands (MWh)	T-Demand4 (>85%)	2,961,464.19	3,212,244.29	139,932	∞
Transmission Connected	2 bands (Voltage)	T-Demand1 (<=132kV)	423,931.64	459,830.65		
Transmission Connected	2 bands (Voltage)	T-Demand2 (>132kV)	940,627.43	1,020,280.81		
		Demand Residual (£m)	**2,400.1**	**2,603.3**		
		Locational Rev. Recovery (£m)	**91.4**	**- 111.9**		
		Embedded Export (£m)	**13.7**			
		Total Demand Revenue (£m)	**2,477.7**			

6

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 Thursday 13th May 2021. 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 2022/23 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 for demand, and adjustment for generation, is also used to ensure the correct proportion of revenue is collected from demand and generation. The locational and residual / adjustment tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate.

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

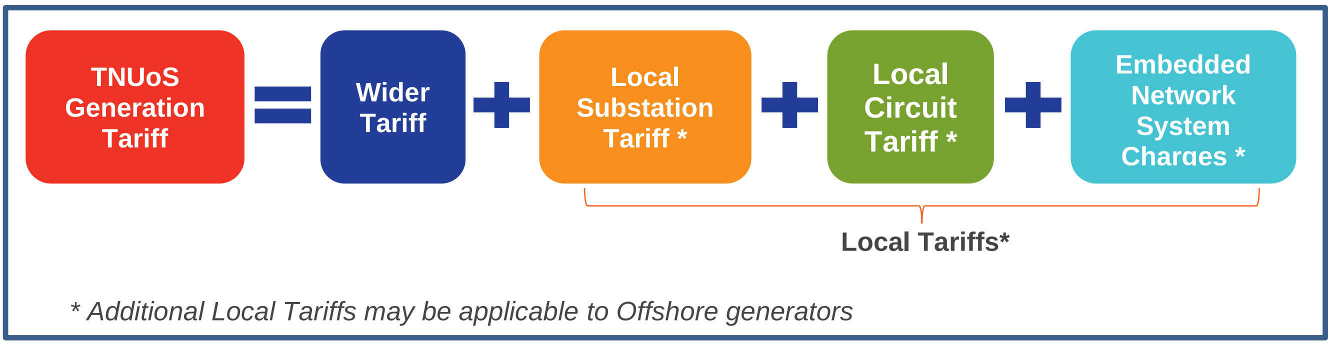
Generation charging principles

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

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

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

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



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)

Peak Element + (Year Round Shared Element × ALF) + (Year Round Not Shared Element × ALF) + Adjustment Element

Conventional Low Carbon Generators

(Hydro, Nuclear)

Peak Element + (Year Round Shared Element × ALF) + Year Round Not Shared Element + Adjustment Element

Intermittent Generators

(Wind, Wave, Tidal)

(Year Round Shared Element × ALF) + Year Round Not Shared Element + Adjustment Element

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 66.

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

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

2.50/MWh on average. For this report, all local onshore tariffs (circuit and substation) and Offshore tariffs are excluded from the €2.50/MWh cap in line with Ofgem's decision on code modification CMP317/327. There is still a requirement for a negative adjustment as part of the outcome for CMP317/327 when the TGR is set to £0/kW.

Local substation tariffs

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

Local onshore substation tariffs are set at the start of each TO financial regulatory period and increased by CPIH each year from the start of the RIIO-2 price control period.

Local circuit tariffs

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

Embedded network system charges

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

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:

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

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

TNUoS charges are billed each month for the month ahead.

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

[12] Distribution network Use of System charges

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

There is a guide to triads and HH charging available on our website[14].

Embedded Export Tariffs (EET)

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

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

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

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

Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads. SVA registered generators are not paid directly by 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.

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

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 2022/23, the current calculation methodology for demand tariffs remains the same. As of 2023/24, 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.

B

Appendix B: Changes and proposed changes to the charging methodology

Changes and proposed changes to the charging methodology

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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2022/23 – 2026/27. 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 27 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP280	Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users	Remove demand residual charges from generation and storage	April 2022, if approved
CMP286/287	Improving TNUoS Predictability Through Increased Notice	Increase notice period of tariff setting input data	to be confirmed
CMP315	TNUoS: Review of the expansion constant and the elements of the transmission system charge	changes to TNUoS tariff calculation parameters	to be confirmed
CMP316	TNUoS Arrangements for Co-located Generation Sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types	to be confirmed
CMP330	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	to be confirmed
CMP331	Option to replace generic Annual Load Factors (ALFs) with site specific ALFs	Introduce an option for site specific ALFs	to be confirmed
CMP335/336	Transmission Demand Residual - Billing and consequential changes	Part of the Transmission Demand Residual changes (TDR)	April 2023, if approved
CMP340/343	Transmission Demand Residual bandings and allocation for 1 April 2022 implementation (TCR)	Part of the Transmission Demand Residual changes (TDR)	April 2023, if approved
CMP344	Clarification of Transmission Licensee revenue recovery and the treatment of revenue adjustments in the Charging Methodology	Fixing the TNUoS revenue at each onshore price control period for onshore TOs, and at the point of asset transfer for OFTOs.	to be confirmed

CMP363/364	TNUoS Demand Residual charges for transmission connected sites with a mix of Final and non-Final Demand & Definition changes for CMP363	Part of the Transmission Demand Residual changes (TDR)	April 2023, if approved
CMP368/369	Charges for the Physical Assets Required for Connection	Part of the Transmission Generation Residual (TGR)	April 2022, if approved

* We are aware of some CUSC mods that will affect TNUoS. As their impacts are in a small or localised way, they may not be included in our forecast or in the list.

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 2023/24 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 28 Elements of the demand location tariff for 2022/23

Zone	Zone Name	Gross Half-Hourly Demand Tariff		
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)	Residual (£/kW)
1	Northern Scotland	-3.116462	-27.428739	53.285456
2	Southern Scotland	-3.215416	-18.599220	53.285456
3	Northern	-4.063048	-7.542140	53.285456
4	North West	-1.585722	-4.140701	53.285456
5	Yorkshire	-3.215572	-1.813832	53.285456
6	N Wales & Mersey	-2.412292	-1.988324	53.285456
7	East Midlands	-2.487282	1.150504	53.285456
8	Midlands	-1.419253	1.634158	53.285456
9	Eastern	1.249970	-0.069565	53.285456
10	South Wales	-3.583402	5.305982	53.285456
11	South East	3.790322	-0.265553	53.285456
12	London	5.603960	1.059458	53.285456
13	Southern	1.809885	3.419941	53.285456
14	South Western	0.780133	6.380386	53.285456

Table 29 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	-2.762225	-27.913054
2	Southern Scotland	-2.855786	-19.057009
3	Northern	-3.486530	-8.456705
4	North West	-2.033096	-3.677330
5	Yorkshire	-2.495343	-2.387378
6	N Wales & Mersey	-2.790590	-1.238734
7	East Midlands	-2.149374	0.915963
8	Midlands	-1.780912	2.964163
9	Eastern	0.927970	-1.166627
10	South Wales	-2.943250	7.170593
11	South East	3.449090	-1.086955
12	London	4.951066	-0.239750
13	Southern	1.700021	3.245027
14	South Western	1.970193	7.748826

Table 30 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	-2.354273	-27.753438
2	Southern Scotland	-1.982043	-18.927017
3	Northern	-2.993836	-8.376123
4	North West	-1.252076	-3.180246
5	Yorkshire	-1.888740	-2.297017
6	N Wales & Mersey	-2.253320	-0.517463
7	East Midlands	-2.102819	0.740274
8	Midlands	-1.833446	3.376028
9	Eastern	0.586033	-1.763713
10	South Wales	-3.858152	6.899710
11	South East	3.070338	-1.742838
12	London	4.544135	-0.965258
13	Southern	1.550537	2.935651
14	South Western	1.475608	8.274774

Table 31 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	-2.376862	-30.251417
2	Southern Scotland	-2.009002	-20.489673
3	Northern	-2.313090	-9.560276
4	North West	-1.158257	-3.856443
5	Yorkshire	-1.334297	-3.261441
6	N Wales & Mersey	-2.072121	-1.492766
7	East Midlands	-1.998422	0.598284
8	Midlands	-1.573709	2.881067
9	Eastern	0.299118	-1.431282
10	South Wales	-4.061220	7.126993
11	South East	2.826528	-1.426369
12	London	4.289391	-0.597932
13	Southern	1.319454	3.257946
14	South Western	1.316370	8.431876

Table 32 Elements of the demand location tariff for 2026/27

Zone	Zone Name	Gross Half-Hourly Demand	
		Peak Security Transport (£/kW)	Year Round Transport (£/kW)
1	Northern Scotland	-1.747710	-32.390004
2	Southern Scotland	-2.058182	-21.798963
3	Northern	-2.569646	-10.233048
4	North West	-1.130948	-4.795082
5	Yorkshire	-1.586568	-4.051723
6	N Wales & Mersey	-1.942691	-2.628673
7	East Midlands	-2.086944	0.325508
8	Midlands	-1.510327	2.271114
9	Eastern	-0.064985	-1.430329
10	South Wales	-1.577237	9.764391
11	South East	2.468648	-1.323390
12	London	3.963635	-0.390616
13	Southern	1.211414	3.523294
14	South Western	1.696724	9.703631

D

Appendix D: 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 2021/22 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2015/16 to 2019/20. Generators which commissioned after 1 April 2017 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 2022/23 TNUoS Tariffs will be updated by November Draft tariffs 2021. The specific and generic ALFs for 2021/22 tariffs, as used in this forecast, are published here: https://www.nationalgrideso.com/document/186166/download.

Generic ALFs

Table 33 Generic ALFs

Technology	Generic ALF
Gas_Oil	0.4602%
Pumped_Storage	9.7926%
Tidal	23.1000%
Biomass	49.5396%
Wave	2.9000%
Onshore_Wind	36.0719%
CCGT_CHP	51.0635%
Hydro	41.8887%
Offshore_Wind	49.4981%
Coal	20.3859%
Nuclear	75.8434%
Solar	10.8000%

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.

E

Appendix E: Contracted generation

For the complete breakdown of Contracted TEC per generator for each year, please see Table A Contracted TEC by Generator in the Tables spreadsheet published on our website here, under 2022/23 tariffs. The data in Table A is taken from the TEC register from March 2021.

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 2022/23 tariffs, using the TEC register as of 31 October 2021, as stated by the CUSC 14.15.6.

Table 34 Contracted TEC by generation zone

Zone	Zone Name	2022/23 (MW)	2023/24 (MW)	2024/25 (MW)	2025/26 (MW)	2026/27 (MW)
1	North Scotland	2,223	2,260	4,088	5,277	6,904
2	East Aberdeenshire	2,080	2,080	2,080	2,080	3,480
3	Western Highlands	513	513	614	614	614
4	Skye and Lochalsh	41	41	41	91	331
5	Eastern Grampian and Tayside	1,628	1,628	1,796	1,996	2,135
6	Central Grampian	64	64	64	64	64
7	Argyll	166	166	166	373	574
8	The Trossachs	520	520	520	520	520
9	Stirlingshire and Fife	120	120	320	320	320
10	South West Scotland	3,517	3,844	5,237	5,604	5,856
11	Lothian and Borders	3,525	4,786	7,061	7,561	7,645
12	Solway and Cheviot	451	451	501	1,251	1,375
13	North East England	3,467	4,836	5,176	5,176	6,026
14	North Lancashire and The Lakes	4,189	4,239	4,239	4,239	4,239
15	South Lancashire, Yorkshire and Humbe	11,534	13,457	18,925	18,975	20,865
16	North Midlands and North Wales	12,163	12,263	12,572	13,422	13,759
17	South Lincolnshire and North Norfolk	5,461	7,175	8,875	11,275	11,275
18	Mid Wales and The Midlands	8,067	9,653	12,441	16,509	16,629
19	Anglesey and Snowdon	1,794	1,794	2,914	2,914	2,914
20	Pembrokeshire	3,053	3,053	3,053	3,053	3,144
21	South Wales & Gloucester	2,006	2,348	2,505	2,505	2,725
22	Cotswold	1,404	1,454	1,454	1,454	1,454
23	Central London	144	194	194	251	251
24	Essex and Kent	14,641	16,961	19,341	20,890	20,968
25	Oxfordshire, Surrey and Sussex	2,570	2,947	5,103	5,253	6,460
26	Somerset and Wessex	3,479	3,529	5,467	8,636	8,706
27	West Devon and Cornwall	1,095	1,195	1,245	1,295	1,295

F

Appendix F 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. Revenue forecasts by Onshore TOs were based on Ofgem's final determination on RIIO-T2 and did not reflect the CMA appeals they made against RIIO-T2 parameters.

The revenue forecast for 2022/23 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.

The NGESO TNUoS revenue forecast has been calculated under the draft NGESO licence for RIIO-2, published on Ofgem's website on 17th December. The revenue breakdown table shows details of the pass-through TNUoS revenue items under NGESO's licence conditions.

Table 35 NGESO revenue breakdown

ESO	NGESO TNUoS Other Pass-Through				
Term	2022/23	2023/24	2024/25	2025/26	2026/27
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6	0.6	0.6
Network Innovation Competition (NICFt)	30.9	30.9	30.9	30.9	30.9
Offshore Transmission Revenue (OFTOt) and Interconnectors Cap&Floor Revenue Adjustment (TICFt)	552.8	656.5	757.1	876.4	936.7
NGET revenue pas-through (NGETTOt)	1764.5	1704.4	1674.6	1645.0	1645.0
SPT revenue pass-through (TSPt)	348.7	370.9	361.6	337.6	337.6
SHETL revenue pass-through (TSHt)	632.7	582.9	586.7	563.4	563.4
ESO Bad debt (BDt)	3.3	3.3	3.4	3.4	3.5
ESO other pass-through items (LFt + ITCt + Termt + TSt +DISt etc)	32.6	32.6	32.6	32.6	32.6
ESO legacy adjustment (LARt)	0.0	0.0	0.0	0.0	0.0
Total	**3366.0**	**3382.1**	**3447.4**	**3489.8**	**3550.2**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The baseline revenue forecasts made by onshore TOs were largely based on projects with a high level of certainty at the time of final proposals. The spending profile results in a lower value for fast money which is based on a consistent capitalisation rate through the price control period, and thus a year-on-year reduction in forecast revenues. However, various re-opener mechanisms (e.g. net zero) means that the TOs are able to put in submissions for additional projects throughout the RIIO-T2 period, which may increase their revenues.

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have made appeals to CMA against Ofgem's determination on certain RIIO-T2 parameters, and may potentially change the revenue forecast upon CMA's decision (due by October 2021).

We appreciate the impact of revenue uncertainty on customers and particularly suppliers. However, we do not have access to TOs' business plan data (apart from data already available in the public domain), and are thus not in a unique position to assess the likely variation to their revenue due to financial parameter (e.g. rate of return) changes. Therefore, in this report, we did not undertake any sensitivity analysis on the likely revenues if the CMA appeal is upheld.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2022/23 is forecast to be £569.3m, an increase of £20.3m from our 2021/22 Final tariffs. 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, and interconnectors' Cap & Floor framework. The latest interconnector revenue forecast received in January/February shows contribution made by interconnectors decrease 2022/23 – 2026/27 TNUoS revenues.

Table 36 NGET revenue forecast

Revenue (£m)	Total Allowed Revenue [ARt=ADJRt+Kt+LARt]				
Regulatory Year RPIFt	2022/23	2023/24	2024/25	2025/26	2026/27
National Grid Electricity Transmission	1764.5	1704.4	1674.6	1645.0	1645.0

Table 37 SPT revenue forecast

Revenue (£m)	Total Allowed Revenue [ARt=ADJRt+Kt+LARt]				
Regulatory Year RPIFt	2022/23	2023/24	2024/25	2025/26	2026/27
Scottish Power Transmission	348.7	370.9	361.6	337.6	337.6

Table 38 SHETL revenue forecast

Revenue (£m)	Total Allowed Revenue [ARt=ADJRt+Kt+LARt]				
Regulatory Year RPIFt	2022/23	2023/24	2024/25	2025/26	2026/27
SHE Transmission	632.7	582.9	586.7	563.4	563.4

Table 39 Offshore revenues

Offshore Transmission Revenue Forecast							
Regulatory Year	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Notes
Barrow	6.7	6.8	7.1	7.3	7.5	8.0	Current revenues plus indexation
Gunfleet	8.4	8.5	8.8	9.1	9.3	9.7	Current revenues plus indexation
Walney 1	15.3	15.5	16.1	16.6	17.1	17.8	Current revenues plus indexation
Robin Rigg	9.4	9.6	9.9	10.2	10.5	10.7	Current revenues plus indexation
Walney 2	15.1	15.9	16.7	17.1	17.6	18.3	Current revenues plus indexation
Sheringham Shoal	23.4	23.8	24.4	25.2	25.9	26.6	Current revenues plus indexation
Ormonde	14.1	14.4	14.8	15.3	15.7	16.5	Current revenues plus indexation
Greater Gabbard	32.1	32.6	33.8	34.4	35.7	36.7	Current revenues plus indexation
London Array	44.7	45.6	46.9	48.3	49.7	51.2	Current revenues plus indexation
Thanet	20.8	21.1	21.9	22.5	23.3	24.1	Current revenues plus indexation
Lincs	30.0	31.1	31.7	32.6	33.5	34.8	Current revenues plus indexation
Gwynt y mor	32.9	31.4	32.3	33.2	34.2	35.0	Current revenues plus indexation
West of Duddon Sands	25.3	24.9	25.6	26.3	27.1	28.0	Current revenues plus indexation
Humber Gateway	14.4	13.3	13.7	14.1	14.5	14.8	Current revenues plus indexation
Westermost Rough	14.1	14.5	14.9	15.3	15.7	16.8	Current revenues plus indexation
Burbo Bank	14.1	14.5	14.9	15.3	15.8	15.8	Current revenues plus indexation
Dudgeon	19.6	20.5	21.0	21.6	22.2	23.2	Current revenues plus indexation
Race Bank	27.4	28.4	29.2	30.1	31.0	31.6	Current revenues plus indexation
Galloper	17.1	17.5	18.0	18.6	19.1	20.4	Current revenues plus indexation
Walney 3	13.5	13.9	14.3	14.8	15.2	14.9	Current revenues plus indexation
Walney 4	13.5	13.9	14.3	14.8	15.2	14.5	Current revenues plus indexation
Hornsea 1A	95.6	16.4	16.8	17.3	17.8	19.4	Asset transferred in 2021/22
Hornsea 1B		16.4	16.8	17.3	17.8	18.4	Asset transferred in 2021/22
Hornsea 1C		16.4	16.8	17.3	17.8	19.1	Asset transferred in 2021/22
Forecast to asset transfer to OFTO in 2021/22		138.3	142.1	146.4	150.8	157.0	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2022/23		13.3	27.8	28.6	29.5	31.0	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2023/24			70.9	78.6	81.0	82.4	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2024/25				87.0	135.4	138.7	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2025/26					63.1	64.1	National Grid ESO Forecast
Forecast to asset transfer to OFTO in 2026/27						32.8	National Grid ESO Forecast
Offshore Transmission Pass-Through (B7)	507	618	721	835	969	1032	

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

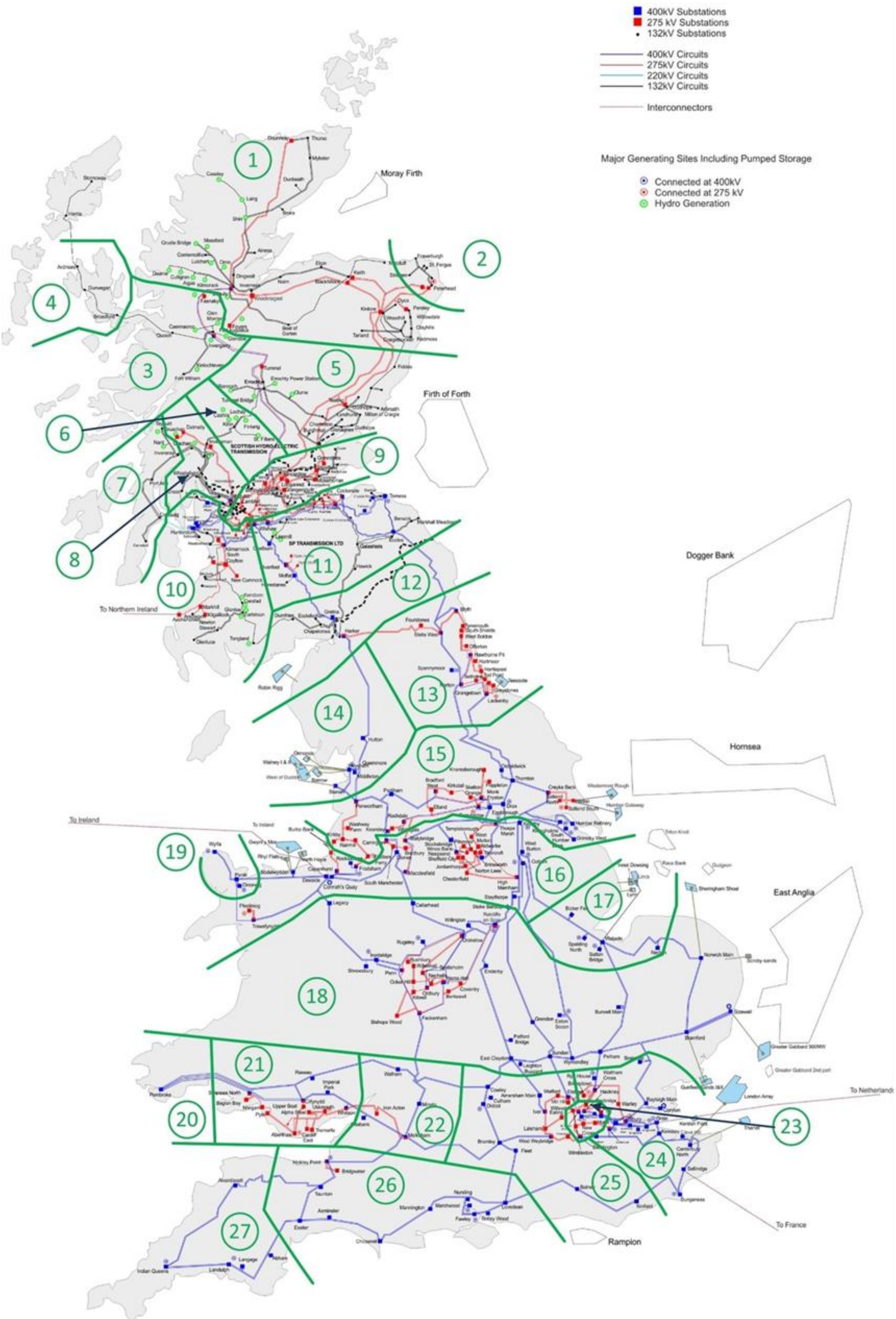
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

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

G

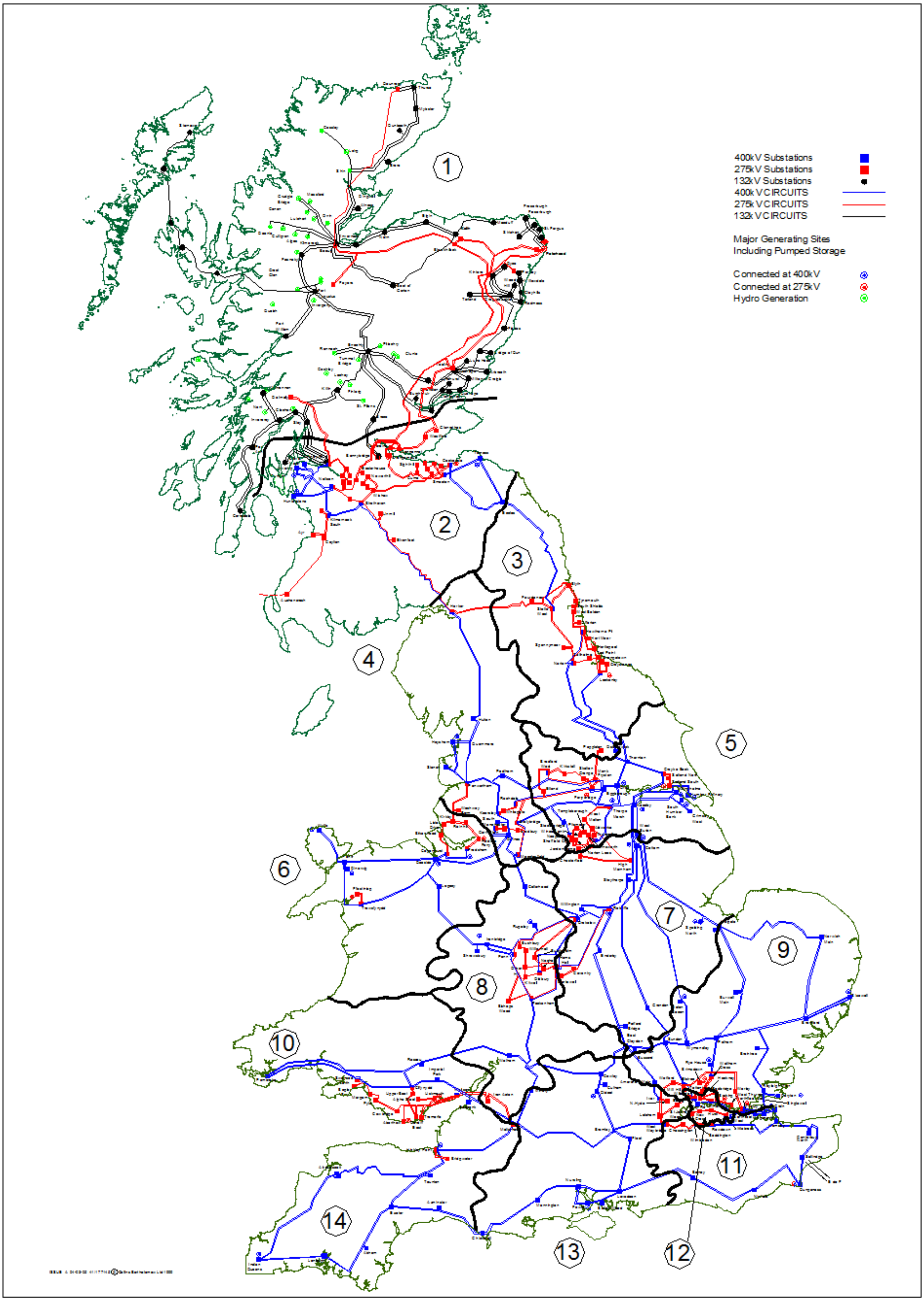
Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



H

Appendix H: Demand zones map


400kV Substations
275kV Substations
132kV Substations
400kV CIRCUITS
275kV CIRCUITS
132kV CIRCUITS
Major Generating Sites
Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
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Appendix I: 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.

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

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