nationalgridESO

Draft TNUoS Tariffs for 2021/22

National Grid Electricity System Operator

November 2020

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Executive summary

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

Under the National Grid Electricity System Operator (NGESO) licence condition C4 and Connection and Use of System Code (CUSC) paragraph 14.29, we publish the draft TNUoS tariffs for year 2021/22 (November Tariffs) on our website[1].

These forecasted tariffs are for charging year 2021/22 and has no impact on 2020/21.

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

Major Regulatory Changes - TCR

Ofgem's decision on the Targeted Charging Review (TCR) will affect TNUoS tariffs in two aspects, the Transmission Generation Residual (TGR) and the Transmission Demand Residual (TDR). The TGR changes are planned to be implemented from April 2021 and will affect generation residual tariffs, while the TDR changes are expected to be implemented from April 2022. In this forecast, we have included TGR only. In addition, we have provided a sensitivity analysis for different definitions of "assets required for connection" which is included in the generation cap calculation.

Price Control Impact

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

The number of generation zones will remain at 27 as in RIIO-1, in light of the conclusion of CMP324/325 (which was approved by Ofgem recently).

COVID19 Impact

The impact of demand suppression due to COVID-19 has been incorporated in the demand charging bases for the Draft Tariffs. Modelling inputs and assumptions will continue to be updated and reviewed in the run up to the final tariffs being published in January.

We currently forecast -4.39% (~£125m) under-recovery of TNUoS for the current year 2020/21. This number will be revised through the year. Any under-recovery will be recovered in charging year 2022/23.

Total revenues to be recovered

Total revenue to be collected is forecast at £3,410m, an increase of £362m from the August forecast. This forecast was provided by TOs' and was largely based on their RIIO-2 business plan. The revenue will be finalized, following Ofgem's final determination, and the final figure will be built in January Final Tariffs. We have undertaken a sensitivity analysis, to illustrate the indicative magnitude of change to revenue, if an alternative annuity factor is applied.

Generation tariffs

The total revenue to be recovered from generators is £813m, an increase of £335m from 2020/21 and a decrease of £13m since the August forecast. This significant increase from 2020/21 is mainly driven by the Targeted Charging Review (TCR) change,

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

which intends to remove the generation residual from TNUoS charge.

The generation charging base has been updated to 71.7GW based on our best view on generation projects for 2021/22. This is a reduction of 5GW] from the August forecast. This view will be further refined ahead of final tariffs. With a decreased generation charging base, the average generation tariff increased by £0.61/kW to £11.35 /kW since the August forecast and the residual tariff increased by £0.21/kW to -£0.03/kw.

Small Generator Discount

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

Demand tariffs

The revenue to be recovered through demand tariffs is currently forecast at £2,596.5m for 2021/22. This value has increased significantly (£374.4m) compared to our August forecast. This is mainly driven by the increased revenue from TOs. As a result, the demand tariffs have increased accordingly. Since the August forecast the demand data (provided as part of the ETYS) which is used to calculate locational demand, has been updated. With this revision, there is an overall reduction in net locational demand for 2021/22 down to 46.4GW from 49.7GW used in previous forecasts for 2021/22.

The average HH demand tariff is now forecast at £52.46/kW for 2021/22, an increase of £7.65/kW from the August forecast) and £2.90 from 2020/21). The average NHH demand tariff is forecast at 6.56p/kWh, an increase of 0.87p/kWh from the August forecast) and 0.54p/kWh from 2020/21).

£15.1m will be payable through the Embedded Export Tariff (EET) an increase of £1.54m from our previous forecast. The average EET has increased by £0.41/kW to £2.27/kW. This increase is mainly due to the changes seen in locational demand.

Consumer bill impact

Using TO's revenue forecast, TNUoS charge would have an impact of £36.76 on consumer bill, an increase of~£5 from August forecast. Our sensitivity analysis with CMA's rate of return figures shows consumer bill impact will reduce to £31.87, in line with our August forecast. Our consumer bill calculation is only affected by NHH tariffs, and not by HH or generation tariffs.

Sensitivity Scenarios

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

- If CMP344 is implemented and amends the treatment of revenue adjustments
- If congestion management costs are included in the generation EU cap
- If the "narrow" definition of Generator Only Spurs (GOS) is chosen. This is to illustrates the likely range of GOS values.
- If the expansion constant and factors values are reset based on the TOs historical data.
- If an alternative annuity factor is applied, the impact on the revenue.
- If different decimal places are applied to the locational security factor

Next TNUoS tariff publications

The timetable of TNUoS tariffs forecasts throughout year 2020/21 is available on our website[2].

Our next TNUoS tariff publication will be the final TNUoS tariffs in January 2021.

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

Feedback

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

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

[2] https://www.nationalgrideso.com/document/162406/download

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

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

Our contact details

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Forecast Overview

This report

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

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

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

Changes to the charging methodology

Ofgem's Targeted Charging Review (TCR)

On 21 November 2019, the Authority 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. These changes will take effect from April 2021.

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

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

Our 2021/22 tariff forecast is based on the methodology defined in the CUSC. However, we have also incorporated the potential impacts by TGR which is due to take effect from April 2021 and is not approved yet, to illustrate the likely magnitudes of tariffs changes to customers. We have assumed that all local charges are no longer included in the European generation cap to increase the residual closer to zero. We have also assumed there will need to be a small adjustment factor to ensure generation charges are still compliant with the cap. For the purposes of this report we have still called this the residual.

Regulatory changes

CMP325 (generation rezoning) was approved in November and is reflected in this forecast. The generation zone boundaries will remain unchanged from 2020/21, as a result of CMP325.

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

New Price Control RIIO-2

In accordance with the CUSC, at the start of the next price control in April 2021, various aspects of the TNUoS charging parameters are required to be revised based on new data for the price-control and apply from 1 April 2021. They are listed in the table below with assumptions applied to the Draft tariffs.

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

A. RIIO-2 Assumptions

Component	Description	Assumptions for 2021/22
Maximum Allowed Revenue	The MAR for onshore TOs in the new price control period will be determined by December.	Our assumption in these tariffs is based on current onshore TOs' MAR forecast under relevant STC procedures. We have also undertaken a sensitivity analysis to show the possible magnitude of change.
Generation zones	There are currently 27 generation zones.	Following approval of CMP325, the generation zonal boundaries have been fixed and remain as 27.
Expansion Constant and Factors	The expansion constant and expansion factors need to be recalculated based on TOs' business plans and costs of investments. The expansion constant represents the cost of moving 1MW, 1km using 400kV OHL line. The expansion factors represent how many times more expensive moving 1MW, 1km is using different voltages and types of circuit.	Our assumption in the Draft tariffs is that the expansion constant for RIIO1 continues with a RPI uplift and that the expansion factors are unchanged.
Locational Onshore Security Factor	The security factor is currently 1.8. This has been recalculated in August, and the new value is slightly below 1.8, and has therefore been rounded to 1.8.	Our assumption in these tariffs is the security factor remains as 1.8. We are currently consulting the industry on the different decimal places for the security factor and will apply the consultation outcome in the final tariffs.
Local Substation Tariffs	Local Substation tariffs will be recalculated in preparation for the start of the price control based on TO asset costs.	The local substation tariffs have been updated based on TOs data and factored into the Draft Tariffs for 2021/22. These tariffs could potentially be impacted by Ofgem's final determination and may be updated for Final Tariffs.
Offshore Local tariffs	The elements for the offshore tariffs will be recalculated in preparation for the start of the price control, based on updated forecasts of OFTO revenue, and adjusting for differences in actual OFTO revenue to forecast revenue in RIIO-T1.	The offshore tariffs have been recalculated to adjust for differences in actual OFTO revenue to forecast revenue in RIIO-T1. We have recalculated an indicative Offshore substation discount and included it in the offshore local tariffs in this report.
Avoided GSP Infrastructure Credit (AGIC)	The AGIC is a component of the Embedded Export Tariff, paid to 'exporting demand' at the time of Triad. It will be recalculated based on up to 20 schemes from the RIIO-2 price-control period.	AGIC has been updated for Draft Tariffs

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Generation tariffs

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

1. Generation tariffs summary

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

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

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

We have included some sensitivities to model what the tariffs might be if the definition of what is included in the European cap changes.

Table 1 Summary of generation tariffs

Generation Tariffs (£/kW)	2021/22 August	2021/22 Draft	Change since last forecast
Residual	- 0.232751	- 0.027640	0.205111
Average Generation Tariff*	10.740461	11.351149	0.610689

*N.B. These generation average tariffs include local tariffs

The average generation tariff is calculated by dividing the total revenue payable by generation over the generation charging base in GW.

Average generation tariffs have increased by £0.61/kW. This is mainly driven by decrease in the generation charging base, so the generation revenue is spread across less MWs. These average tariffs include revenues from local tariffs.

Since the August forecast the generation residual has increased to -0.03/kW due to the decrease in generation revenue and the generation charging base.

2. Generation wider tariffs

The following section summarises the wider generation tariffs for 2021/22. A brief description of generation wider tariff structure can be found in Appendix A.

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

The classifications of generator type are listed below:

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

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

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

Table 2 Generation wider tariffs

		Tariffs (£/kW)						
						Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.233515	20.365952	19.336158	- 0.027640	35.967563	39.834795	27.454899
2	East Aberdeenshire	3.233915	10.749346	19.336158	- 0.027640	27.274678	31.141910	23.608256
3	Western Highlands	3.941805	18.596782	18.609310	- 0.027640	33.679039	37.400901	26.020383
4	Skye and Lochalsh	- 0.615917	18.596782	20.430374	- 0.027640	30.578168	34.664243	27.841447
5	Eastern Grampian and Tayside	4.748428	13.720708	15.692907	- 0.027640	28.251680	31.390261	21.153550
6	Central Grampian	4.382826	14.674469	16.787796	- 0.027640	29.524998	32.882557	22.629944
7	Argyll	2.713385	12.693899	25.645643	- 0.027640	33.357379	38.486507	30.695563
8	The Trossachs	3.856094	12.693899	14.471673	- 0.027640	25.560912	28.455246	19.521593
9	Stirlingshire and Fife	2.735806	11.216771	13.214771	- 0.027640	22.253400	24.896354	17.673839
10	South West Scotlands	3.029622	11.576869	13.492567	- 0.027640	23.057531	25.756044	18.095675
11	Lothian and Borders	2.996294	11.576869	6.680246	- 0.027640	17.574346	18.910395	11.283354
12	Solway and Cheviot	2.589885	7.803323	7.484620	- 0.027640	14.792599	16.289523	10.578309
13	North East England	3.432280	6.040201	4.520261	- 0.027640	11.853010	12.757062	6.908701
14	North Lancashire and The Lakes	2.549497	6.040201	1.282715	- 0.027640	8.380190	8.636733	3.671155
15	South Lancashire, Yorkshire and Humber	3.889886	2.459162	0.357060	- 0.027640	6.115224	6.186636	1.313085
16	North Midlands and North Wales	3.250289	0.887136	-	- 0.027640	3.932358	3.932358	0.327214
17	South Lincolnshire and North Norfolk	1.345403	1.591046	-	- 0.027640	2.590600	2.590600	0.608778
18	Mid Wales and The Midlands	1.667277	1.835025	-	- 0.027640	3.107657	3.107657	0.706370
19	Anglesey and Snowdon	4.914741	1.033645	-	- 0.027640	5.714017	5.714017	0.385818
20	Pembrokeshire	7.631323	- 6.465761	-	- 0.027640	2.431074	2.431074	- 2.613944
21	South Wales & Gloucester	3.500007	- 6.809795	-	- 0.027640	- 1.975469	- 1.975469	- 2.751558
22	Cotswold	2.334014	3.607477	- 8.675744	- 0.027640	- 1.748240	- 3.483388	- 7.260393
23	Central London	- 3.776917	3.607477	- 5.655340	- 0.027640	- 5.442847	- 6.573915	- 4.239989
24	Essex and Kent	- 3.419021	3.607477	-	- 0.027640	- 0.560679	- 0.560679	1.415351
25	Oxfordshire, Surrey and Sussex	- 1.011088	- 1.924661	-	- 0.027640	- 2.578457	- 2.578457	- 0.797504
26	Somerset and Wessex	- 2.305262	- 3.396104	-	- 0.027640	- 5.049785	- 5.049785	- 1.386082
27	West Devon and Cornwall	- 2.590642	- 8.527674	-	- 0.027640	- 9.440421	- 9.440421	- 3.438710

3. Changes to wider tariffs since the August tariff forecast

The following section provides details of the wider and local generation tariffs in the draft forecast for 2021/22 and explains how these have changed since the August forecast.

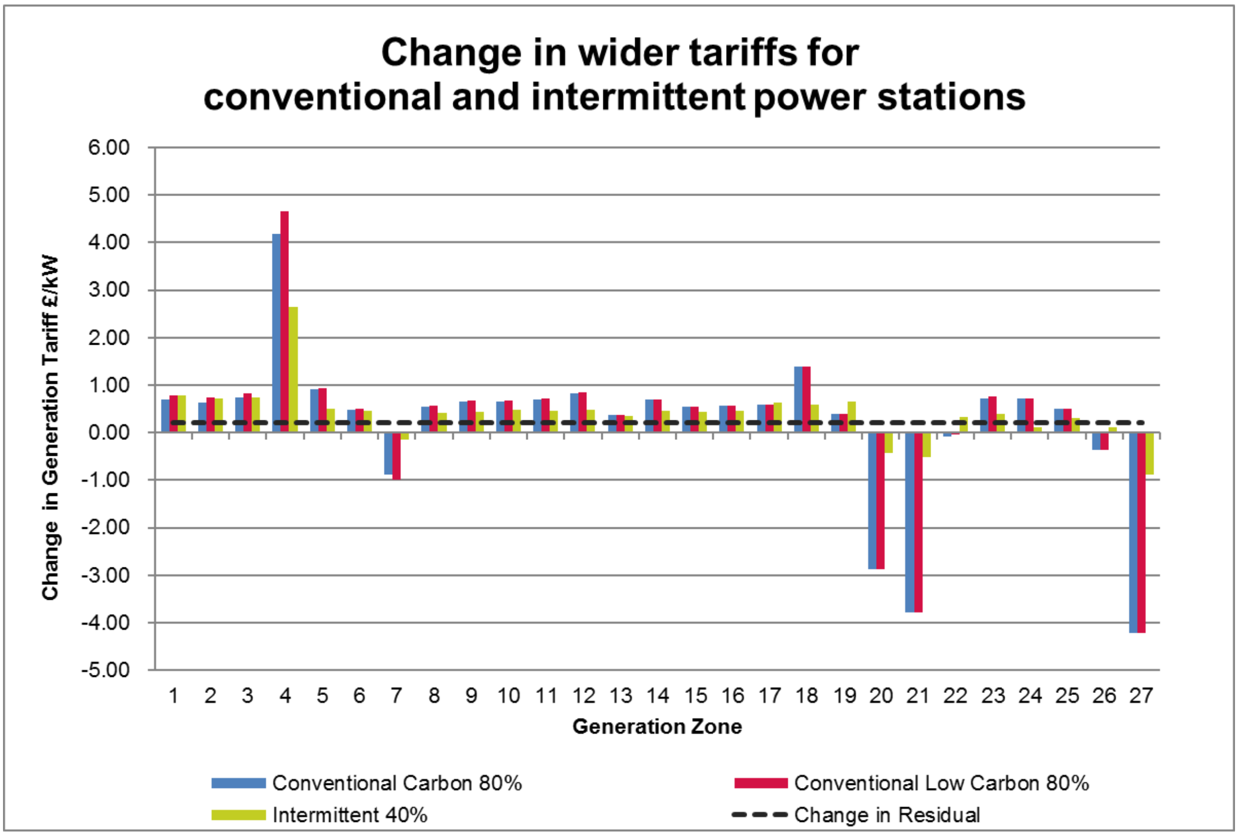
The next table and chart show the changes in wider generation TNUoS tariffs since the August 2020/21 Tariffs with the example Conventional Carbon, Conventional Low Carbon and Intermittent tariffs. The Conventional tariffs use a load factor of 80%, and the Intermittent tariffs use a 40% load factor. All the examples are for illustration purposes only.

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

Table 3 Generation wider tariff changes since August

Zone	Zone Name	Wider Generation Tariffs (£/kW) Conventional Carbon 80% 2021/22 August	Conventional Carbon 80% 2021/22 Draft	Conventional Carbon 80% Change	Conventional Low Carbon 80% 2021/22 August	Conventional Low Carbon 80% 2021/22 Draft	Conventional Low Carbon 80% Change	Intermittent 40% 2021/22 August	Intermittent 40% 2021/22 Draft	Intermittent 40% Change	Change in Residual
1	North Scotland	35.274428	35.967563	0.693135	39.047686	39.834795	0.787109	26.669580	27.454899	0.785318	0.205111
2	East Aberdeenshire	26.632864	27.274678	0.641814	30.406122	31.141910	0.735787	22.893911	23.608256	0.714345	0.205111
3	Western Highlands	32.942153	33.679039	0.736886	36.583199	37.400901	0.817701	25.287880	26.020383	0.732503	0.205111
4	Skye and Lochalsh	26.389325	30.578168	4.188843	30.011005	34.664243	4.653237	25.191049	27.841447	2.650398	0.205111
5	Eastern Grampian and Tayside	27.341760	28.251680	0.909920	30.446901	31.390261	0.943360	20.644432	21.153550	0.509118	0.205111
6	Central Grampian	29.049413	29.524998	0.475585	32.378388	32.882557	0.504169	22.172202	22.629944	0.457742	0.205111
7	Argyll	34.242806	33.357379	- 0.885428	39.466308	38.486507	- 0.979801	30.837805	30.695563	- 0.142242	0.205111
8	The Trossachs	25.013958	25.560912	0.546953	27.892180	28.455246	0.563066	19.111406	19.521593	0.410187	0.205111
9	Stirlingshire and Fife	21.593847	22.253400	0.659552	24.221321	24.896354	0.675033	17.238955	17.673839	0.434884	0.205111
10	South West Scotlands	22.408012	23.057531	0.649519	25.083813	25.756044	0.672231	17.612373	18.095675	0.483301	0.205111
11	Lothian and Borders	16.877376	17.574346	0.696970	18.195474	18.910395	0.714921	10.823854	11.283354	0.459499	0.205111
12	Solway and Cheviot	13.963422	14.792599	0.829178	15.443995	16.289523	0.845529	10.095532	10.578309	0.482777	0.205111
13	North East England	11.478354	11.853010	0.374656	12.388323	12.757062	0.368739	6.546961	6.908701	0.361741	0.205111
14	North Lancashire and The Lakes	7.685003	8.380190	0.695187	7.928241	8.636733	0.708492	3.213305	3.671155	0.457851	0.205111
15	South Lancashire, Yorkshire and Humber	5.575947	6.115224	0.539276	5.646358	6.186636	0.540278	0.873377	1.313085	0.439707	0.205111
16	North Midlands and North Wales	3.368012	3.932358	0.564345	3.368012	3.932358	0.564345	- 0.124780	0.327214	0.451994	0.205111
17	South Lincolnshire and North Norfolk	2.000066	2.590600	0.590534	2.000066	2.590600	0.590534	- 0.021509	0.608778	0.630287	0.205111
18	Mid Wales and The Midlands	1.723622	3.107657	1.384035	1.723622	3.107657	1.384035	0.108472	0.706370	0.597898	0.205111
19	Anglesey and Snowdon	5.322926	5.714017	0.391091	5.322926	5.714017	0.391091	- 0.260080	0.385818	0.645898	0.205111
20	Pembrokeshire	5.314758	2.431074	- 2.883684	5.314758	2.431074	- 2.883684	- 2.195841	- 2.613944	- 0.418104	0.205111
21	South Wales & Gloucester	1.799154	- 1.975469	- 3.774623	1.799154	- 1.975469	- 3.774623	- 2.242097	- 2.751558	- 0.509461	0.205111
22	Cotswold	- 1.664316	- 1.748240	- 0.083924	- 3.440793	- 3.483388	- 0.042596	- 7.586895	- 7.260393	0.326502	0.205111
23	Central London	- 6.160795	- 5.442847	0.717947	- 7.347505	- 6.573915	0.773589	- 4.638061	- 4.239989	0.398072	0.205111
24	Essex and Kent	- 1.278850	- 0.560679	0.718170	- 1.278850	- 0.560679	0.718170	1.295488	1.415351	0.119863	0.205111
25	Oxfordshire, Surrey and Sussex	- 3.083429	- 2.578457	0.504972	- 3.083429	- 2.578457	0.504972	- 1.095790	- 0.797504	0.298285	0.205111
26	Somerset and Wessex	- 4.685198	- 5.049785	- 0.364587	- 4.685198	- 5.049785	- 0.364587	- 1.493397	- 1.386082	0.107315	0.205111
27	West Devon and Cornwall	- 5.221758	- 9.440421	- 4.218663	- 5.221758	- 9.440421	- 4.218663	- 2.546327	- 3.438710	- 0.892382	0.205111

Figure 1 Variation in generation zonal tariffs



Locational changes

The location elements driving the locational tariffs have been updated; these include circuit and locational generation and demand updates. This impacts flows on the network causing changes in the locational element of the tariffs; this resulted in greater increase in zone 4 and a large decrease in zones 20,21 and 27.

Zone 4 is often sensitive to small changes to flows due to little generation being connected there and long radial circuits.

Zones 20, 21 and 27 have decreased due to a large coal site reducing the TEC they are connecting by 1550MW which has had an impact on flows in that area.

Residual changes

There has been <£1.00/kW increase in the generation tariffs in majority of the zones. This is mainly driven by the increase in the residual since August tariffs due to the decrease in the generation revenue.

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 the Draft tariffs, Local Substation tariffs have been updated as part of the RIIO-2 parameter refresh. There has been an overall reduction in tariffs vs the inflated RIIO-1 tariffs used in previous forecast for 2021/22. Whilst there was an increase seen in the input data vs what was submitted for the calculations for RIIO-1 tariffs there has been a greater reduction in the forecasted annuity and overhead factors for 2021/22. These factors are based on the draft determination are still subject to change and will be dependent on Ofgem's final determination.

Table 4 Local substation tariffs

2021/22 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.167824	0.070749	0.057144
<1320 MW	Redundancy	0.375090	0.161831	0.135062
>=1320 MW	No redundancy	n/a	0.219716	0.180959
>=1320 MW	Redundancy	n/a	0.343997	0.290898

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 based on the latest data and for most users, the changes are minimal since the August forecast for 2021/22. Onshore local circuit tariffs are listed in Table 5.

Table 5 Onshore local circuit tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.693170	Dunhill	1.465377	Marchwood	0.390470
Aberdeen Bay	2.667514	Dunlaw Extension	1.545644	Mark Hill	0.895774
Achruach	4.393209	Edinbane	7.002587	Middle Muir	2.350844
Aigas	0.669121	Ewe Hill	2.490034	Middleton	0.155508
An Suidhe	-0.982412	Fallago	0.448201	Millennium South	0.482939
Arecleoch	2.124876	Farr	3.647698	Millennium Wind	1.867943
Baglan Bay	-0.148579	Fernoch	4.499988	Moffat	0.194852
Beinneun Wind Farm	1.536078	Ffestiniogg	0.258837	Mossford	2.945741
Bhlaraidh Wind Farm	0.660552	Finlarig	0.327589	Nant	- 1.256241
Black Hill	1.588833	Foyers	0.299677	Necton	1.149609
Black Law	1.787702	Galawhistle	3.579857	New Deer	0.194692
BlackCraig Wind Farm	6.440343	Glen Kyllachy	- 0.467985	Rhigos	0.105510
BlackLaw Extension	3.791055	Glendoe	1.881871	Rocksavage	0.018108
Clyde (North)	0.112198	Glenglass	4.922579	Saltend	0.017751
Clyde (South)	0.129752	Gordonbush	0.071177	Sandy Knowe	2.386571
Corriegarth	2.963905	Griffin Wind	9.936006	South Humber Bank	- 0.189686
Corriemoillie	1.702135	Hadyard Hill	2.831775	Spalding	0.289946
Coryton	0.051762	Harestanes	2.586255	Strathbrora	- 0.049415
Cruachan	1.866754	Hartlepool	0.091179	Strathy Wind	1.784321
Crystal Rig	0.141327	Invergarry	0.374388	Stronelairg	1.093264
Culligran	1.773187	Kilgallioch	1.076739	Wester Dod	0.489456
Deanie	2.913092	Kilmorack	0.202051	Whitelee	0.108579
Dersalloch	2.464404	Kype Muir	1.517485	Whitelee Extension	0.301849
Dinorwig	2.454656	Langage	- 0.344948		
Dorenell	2.147072	Lochay	0.374388		
Dumnaglass	1.159563	Luichart	0.586727		

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way they are modelled in the Transport and Tariff model. This table shows the circuits which have been amended in the model to account for the one-off charges that have already been made to the generators. For more information please see CUSC sections 2.14.4, 14.4, and 14.15.15.

Table 6 Circuits subject to one-off charges

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

Please note that these offshore tariffs were recalculated in August, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting. The Offshore substation discount was also recalculated for the RIIO-2 period in August to give an indicative figure. The RPI applied to the discount has been updated since the August forecast.

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

Table 7 Offshore local tariffs 2021/22

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.847343	46.675227	1.159010
Burbo Bank	11.057328	21.346582	-
Dudgeon	16.213542	25.417361	-
Galloper	16.549490	26.155193	-
Greater Gabbard	16.455306	38.045116	-
Gunfleet	19.239008	17.730507	3.313933
Gwynt Y Mor	17.844372	17.710590	-
Humber Gateway	12.188327	27.939147	-
Lincs	16.957830	66.640797	-
London Array	11.475403	39.308601	-
Ormonde	27.175448	50.773900	0.404625
Race Bank	9.794833	27.170573	-
Robin Rigg	- 0.583944	33.842704	10.842987
Robin Rigg West	- 0.583944	33.842704	10.842987
Sheringham Shoal	25.429358	29.935070	0.650700
Thanet	19.382584	36.292362	0.873685
Walney 1	23.47605	46.90995	-
Walney 2	21.84251	44.42657	-
Walney 3	10.06170	20.35939	-
Walney 4	10.06170	20.35939	-
West of Duddon Sands	8.89648	44.31827	-
Westermost Rough	18.28621	31.09982	-

3

Demand tariffs

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

7. Demand tariffs summary

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

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

Table 8 Summary of demand tariffs

HH Tariffs	2021/22 August	2021/22 Draft	Change
Average Tariff (£/kW)	44.812728	52.460812	7.648084
Residual (£/kW)	46.554085	54.342512	7.788427
EET	**2021/22 August**	**2021/22 Draft**	**Change**
Average Tariff (£/kW)	1.859122	2.272481	0.413359
Phased residual (£/kW)	-	-	-
AGIC (£/kW)	2.287880	2.282952	- 0.004928
Embedded Export Volume (GW)	7.312920	6.658889	- 0.654030
Total Credit (£m)	13.595610	15.132202	1.536592
NHH Tariffs	**2021/22 August**	**2021/22 Draft**	**Change**
Average (p/kWh)	5.690194	6.563620	0.873426

Table 9 Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	20.631769	2.731383	-
2	Southern Scotland	29.787898	3.774643	-
3	Northern	42.247971	5.168770	-
4	North West	49.012126	6.135768	-
5	Yorkshire	49.688949	6.035617	-
6	N Wales & Mersey	50.465171	6.122775	-
7	East Midlands	53.518073	6.711876	1.458513
8	Midlands	55.089779	7.022124	3.030219
9	Eastern	55.422177	7.388941	3.362617
10	South Wales	57.425898	6.570524	5.366338
11	South East	57.975131	7.861029	5.915571
12	London	60.452238	6.340861	8.392678
13	Southern	60.122730	7.653066	8.063170
14	South Western	63.007529	8.596217	10.947969

Residual charge for demand:	54.342512

8. Changes since the August Forecast of Tariffs

Demand tariffs have been forecast to increase significantly, the main driver being the increase in the total revenue from the TOs.

The demand charging bases have been updated and have fluctuated marginally since the August forecast. Total Average Gross Demand Triad has decreased slightly, however the Total Average Net Triad has increased from 42.8GW to 43.3GW due to the decrease in the forecast Embedded Export which down from 7.3GW to 6.6GW.

Locational Demand forecasts have been updated with the revised Week24 data (data is provided by DNO's and other distribution connected demand as part of the Electricity Ten Year Statement) for 2021/22. Overall, we are seeing a reduction in locational demand of 3.3GW, down from 49.7GW to 46.4GW. Whilst most zones are forecasting reductions of varying levels, Zones 10 and 14 are showing an increase in demand.

The average HH tariff is forecast at £52.46/kW, an increase of £7.64/kW. The average NHH tariff is forecast at 6.56p/kWh, an increase of 0.87p/kWh.

As per our previous forecast for 2021/22, according to the ESO licence, the Small Generator Discount (SGD) will end 31 March 2021. As such the figures shown in this forecast do not include the Small Generator Discount levy.

The average Embedded Export Tariff is forecasted at £2.27/kW with an increase of £0.41/kW, due to the updated locational demand volumes. Whilst the tariffs have increased by 22% the total credit for embedded export has only increased by £1.5m (11%) to £15.1m due to the decrease in the Embedded Export volumes forecast.

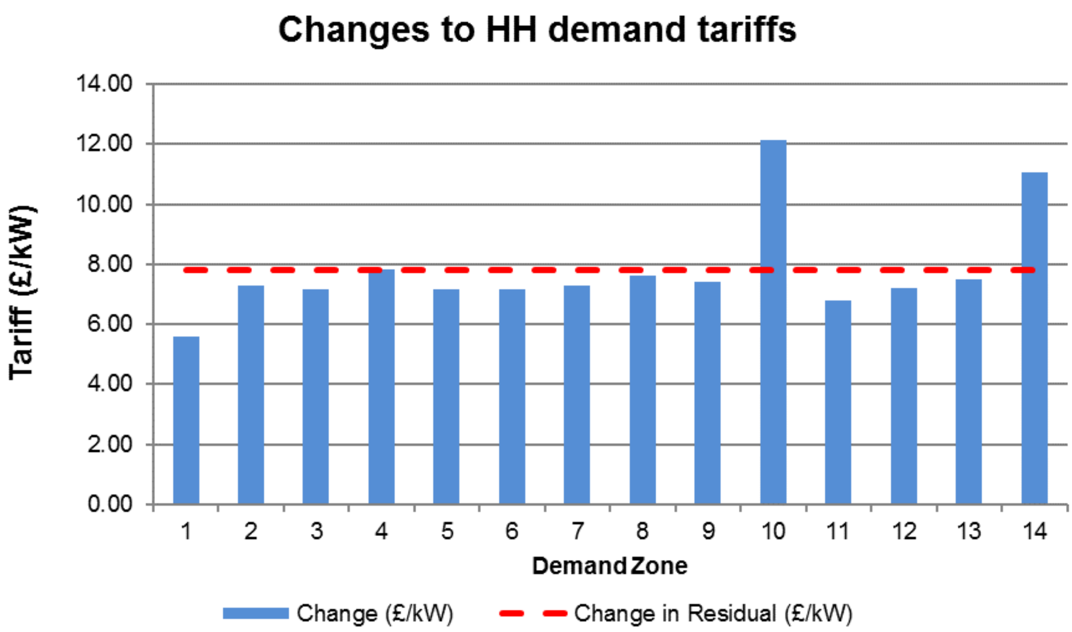
9. Half-Hourly demand tariffs

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

Table 10 Half-Hourly demand tariffs

Zone	Zone Name	2021/22 August (£/kW)	2021/22 Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	15.045719	20.631769	5.586050	7.788428
2	Southern Scotland	22.489331	29.787898	7.298567	7.788428
3	Northern	35.064719	42.247971	7.183252	7.788428
4	North West	41.194336	49.012126	7.817790	7.788428
5	Yorkshire	42.524945	49.688949	7.164004	7.788428
6	N Wales & Mersey	43.295059	50.465171	7.170112	7.788428
7	East Midlands	46.211767	53.518073	7.306306	7.788428
8	Midlands	47.467277	55.089779	7.622502	7.788428
9	Eastern	47.997633	55.422177	7.424544	7.788428
10	South Wales	45.274604	57.425898	12.151294	7.788428
11	South East	51.174255	57.975131	6.800876	7.788428
12	London	53.255446	60.452238	7.196792	7.788428
13	Southern	52.631157	60.122730	7.491573	7.788428
14	South Western	51.929374	63.007529	11.078155	7.788428

Figure 2 Changes to gross Half-Hourly demand tariffs



As shown in the figure above, the HH demand tariff have increased across all zones. The increases are spread relatively equal across the majority of the 14 zones, in-line with the demand residual change. Zones 10 and 14 have increased more than other zones due to the update in locational demand (Week24 data) whilst Zone 1 has had a lower proportion of increase due to a reduction in locational demand, proportionally for that Zone.

The forecasted level of gross HH chargeable demand has increased by 0.1GW in comparison with the August forecast s and is currently forecast at 19.0GW.

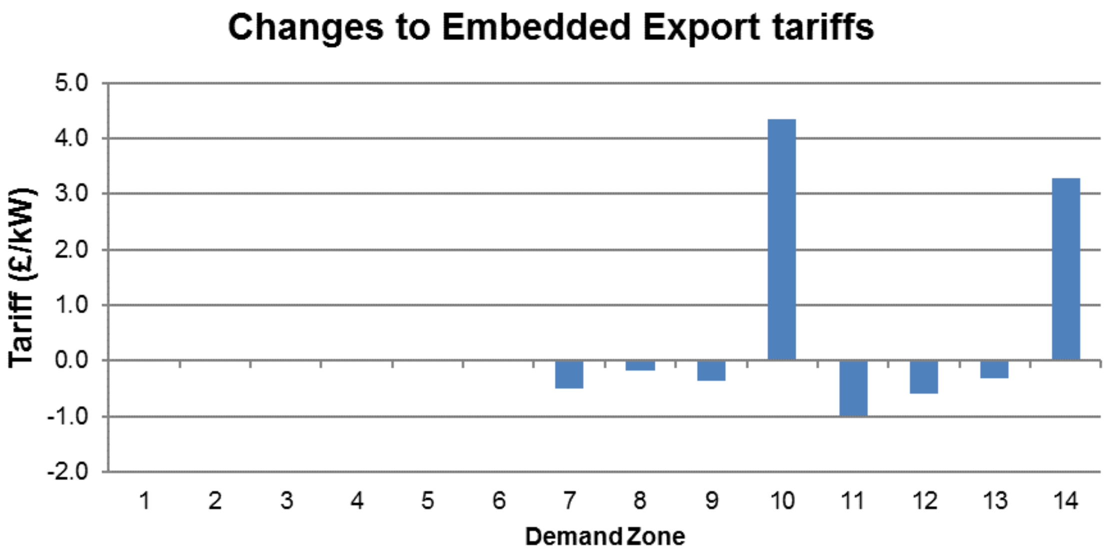
10. Embedded Export Tariffs (EET)

The next table and figure show the forecast 2021/22 EET compared to the August forecast.

Table 11 Embedded Export Tariffs

Zone	Zone Name	2021/22 August (£/kW)	2021/22 Draft (£/kW)	Change (£/kW)
1	Northern Scotland	-	-	-
2	Southern Scotland	-	-	-
3	Northern	-	-	-
4	North West	-	-	-
5	Yorkshire	-	-	-
6	N Wales & Mersey	-	-	-
7	East Midlands	1.945563	1.458513	- 0.487050
8	Midlands	3.201072	3.030219	- 0.170853
9	Eastern	3.731428	3.362617	- 0.368811
10	South Wales	1.008400	5.366338	4.357938
11	South East	6.908051	5.915571	- 0.992480
12	London	8.989242	8.392678	- 0.596564
13	Southern	8.364952	8.063170	- 0.301782
14	South Western	7.663170	10.947969	3.284799

Figure 3 Embedded export tariff changes



There has been a large increase in the average EET forecast for 2021/22 compared to the August forecast, with an increase of £0.41/kW to £2.27/kW. The majority of this increase can be seen in Zones 10 and 14, due to the change in the locational demand forecast for those zones. Embedded export volume from the charging base updates has dropped down to 6.66GW a reduction of 0.87GW. Overall, with the increase in average tariffs and the reduction in Embedded export volumes, the forecasted EET revenue has increased by £1.54m to £15.13m. There has been a slight decrease in the AGIC (Avoided Grid Supply Point Infrastructure Credit) based on forecasted RPI for 2021/22.

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

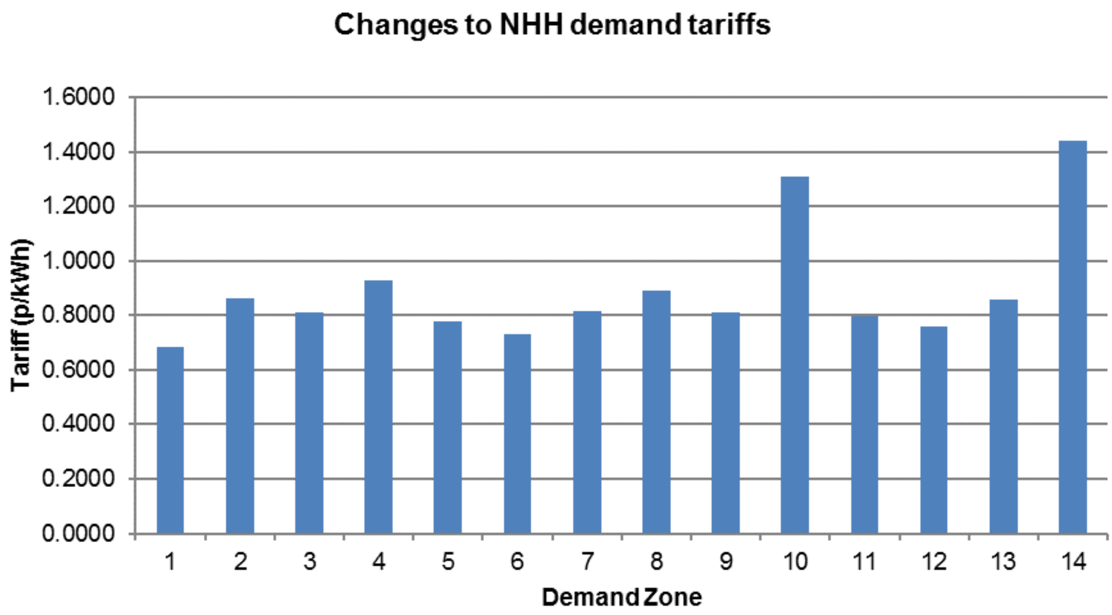
11. Non-Half-Hourly demand tariffs

This table and chart show the difference between the 2021/22 Draft tariffs and the August forecast.

Table 12 Changes to Non-Half-Hourly demand tariffs

Zone	Zone Name	2021/22 August (p/kWh)	2021/22 Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.045854	2.731383	0.685529
2	Southern Scotland	2.913497	3.774643	0.861146
3	Northern	4.357130	5.168770	0.811640
4	North West	5.207812	6.135768	0.927956
5	Yorkshire	5.257421	6.035617	0.778196
6	N Wales & Mersey	5.393179	6.122775	0.729596
7	East Midlands	5.897278	6.711876	0.814598
8	Midlands	6.131826	7.022124	0.890298
9	Eastern	6.576802	7.388941	0.812139
10	South Wales	5.259660	6.570524	1.310864
11	South East	7.062878	7.861029	0.798151
12	London	5.580801	6.340861	0.760060
13	Southern	6.795285	7.653066	0.857781
14	South Western	7.157069	8.596217	1.439148

Figure 4 Changes to Non-Half-Hourly demand tariffs



The average NHH tariff for 2021/22 is forecasted at 6.56p/kWh, which is a 0.87p/kWh increase compared to the August forecast. As with the increase to HH tariffs, the impact of the increased revenue to be collect through to demand, NHH tariffs would increase and the changes in the locational demand would have varying impact across the 14 Zones, as seen above in Figure 4.

4

Overview of data input

Since the August tariffs were published, we have updated:

- Allowed revenue forecast for Transmission Owners
- The local and MITS circuits in the transport model
- The nodal GSP demand in the transport model
- The zonal demand and generation charging bases, and
- RPI

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

12. Changes affecting the locational element of tariffs

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

- Contracted generation and nodal demand as of 31 October 2020;
- Local and MITS circuits as stated in the ETYS; and
- Inflation

Contracted TEC, modelled TEC and Chargeable TEC

Contracted TEC is the volume of TEC with connection agreements for the 2021/22 period, which can be found on the TEC register.[4] The contracted TEC volumes are based on the February 2020 TEC register.

Modelled TEC is the amount of TEC we have entered into the Transport model to calculate MW flows, which also includes interconnector TEC. We have forecast our best view of modelled TEC based on the 31 October 2020 TEC register, in accordance with CUSC 14.15.6.

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

Table 13 Contracted TEC

	2020/21	2021/22 Tariffs			
Generation (GW)	Final	March	August	Draft	Final
Contracted TEC	84.9	93.6	92.7	89.9	
Modelled Best View TEC	84.9	85.8	86.7	89.9	
Chargeable TEC	70.7	76.8	76.9	71.7	

13. Adjustments for interconnectors

When modelling flows on the transmission system, interconnector flows are not included in the Peak model but are included in the Year Round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the calculations of chargeable TEC for either the generation or demand charging bases.

The table below reflects the contracted position of interconnectors for 2021/22 in the interconnector register as of 31 October 2020,

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

Table 14 Interconnectors

Interconnector	Site	Interconnected System	Generation MW			
			Generation Zone	Transport Model Peak	Transport Model Year Round	Charging Base
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
BritNed	Grain 400kV	Netherlands	24	0	1200	0
Belgium Interconnector (Nemo)	Richborough 400kV	Belgium	24	0	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2 Interconnector	Chilling 400KV Substation	France	26	0	1100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	490	0
NS Link	Blyth	Norway	13	0	1400	0

14. Expansion Constant

The expansion constant is the annuitized value of the cost required to transport 1 MW over 1 km. The 2021/22 Expansion Constant is forecast to be £ 15.367047/MWkm. This is based on the RIIO1 value uplifted with RPI as proposed in CMP353. This value will be updated in line with the average May to October RPI and will be finalised with the outturn value by the Final Tariffs. This will be dependent on the Authority’s decision on CMP353. Sensitivity has been provided to show the potential alternative impact.

15. Onshore substation

Local Substation tariffs have been updated for 2021/22 as part of the RIIO-2 parameter refresh. They are based on 2020/21 prices and will be finalized in January with the average May to October RPI.

16. Offshore local tariffs

Local offshore circuit tariffs, local offshore substation tariffs and the ETUoS tariff are indexed in line with the revenue of the relevant Offshore Transmission Owner. These tariffs have been recalculated, in preparation for the RIIO-2 period, to adjust for any differences in the actual OFTO revenue when compared to the forecast revenue used in RIIO-T1 tariff setting These recalculations use the latest forecast of the relevant inflation terms.

17. Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other revenue (for example, Network Innovation Competition for network companies including ESO, TOs and DNOs) are also collected from network users via TNUoS. The total amount recovered is adjusted for interconnector revenue recovery or redistribution. For year 2021/22, as it will be the start of RIIO-T2 price control period, revenue forecast by onshore TOs carry much greater uncertainty compared to previous years, as the onshore TOs have largely based their revenue forecast on TO their RIIO-T2 business plans submitted to Ofgem prior to Ofgem’s Draft Determination. The revenue figures will be finalised by TOs following Ofgem’s Final Determination on RIIO-T2, planned for December, and the updated revenue will be included in January Final tariffs.

CACM pilot project costs

In August 2019, Ofgem published their decision to allow the recovery of some historical CACM Capacity Allocation and Congestion Management) pilot projects costs from TNUoS charges[5]. On 25th November 2020, Ofgem published the follow-up consultation on the cost figures that are to be recovered under the August 2019 decision[6]. According to the consultation letter, Ofgem expects to make a final decision on the assessment of the costs in January 2021, and this will allow IFA, BritNed and Nemo Link to recover the approved costs through the TNUoS charges in 2021/22.

In this forecast, we have not included the amount of CACM costs in the revenue forecast.

Bad debt

In August 2020, Ofgem published a consultation letter on recovery of network charge bad debt7. The letter sets out Ofgem's preferred option which enables recovery of bad debts incurred due to non-payment of network charges on an enduring basis. Under this option, a new bad debt term (BDt) will be introduced in the ESO licence. Subject to Ofgem's Final Determination, the bad debt value will be included in the January final tariffs, it has not been included in the Draft tariffs.

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

Table 15 Allowed revenues

	2021/22 TNUoS Revenue		
£m Nominal	**March Forecast**	**August Forecast**	**Nov Draft**
National Grid Electricity Transmission			
Price controlled revenue	*1,754.9*	*1,753.7*	*1,949.7*
Less income from connections		*29.8*	*29.8*
NGET Income from TNUoS	**1,754.9**	**1,723.9**	**1,919.9**
Scottish Power Transmission			
Price controlled revenue	*389.5*	*384.2*	*410.1*
Less income from connections	*12.7*	*12.7*	*19.5*
SPT Income from TNUoS	**376.7**	**371.5**	**390.6**
SHE Transmission			
Price controlled revenue	*377.5*	*383.4*	*542.6*
Less income from connections	*3.4*	*3.4*	*2.9*
SHE Income from TNUoS	**374.0**	**380.0**	**539.7**
National Grid Electricity System Operator			
Other Pass-through from TNUoS	**17.4**	**17.5**	**14.4**
Offshore (plus interconnector contribution / al	**529.9**	**555.8**	**545.6**
Total to Collect from TNUoS	**3,053.1**	**3,048.6**	**3,410.2**

Please note these figures are rounded to one decimal place.

[5] https://www.ofgem.gov.uk/system/files/docs/2019/08/cacm_decision_-_final_as_published.pdf
[6] https://www.ofgem.gov.uk/ofgem-publications/168119
[7] https://www.ofgem.gov.uk/publications-and-updates/managing-network-charge-bad-debt

18. Generation / Demand (G/D) Split

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

The "EU gen cap"

Section 14.14.5 (v) in the CUSC currently limits average annual generation use of system charges in Great Britain to €2.5/MWh. The revenue that can be recovered from generation dependent on the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin of 20.8% is also applied to reflect revenue and output forecasting accuracy. This revenue figure is normally referred to as the "EU gen cap" and has been locked down in the August tariff forecast.

TCR implementation - TNUoS generation residual (TGR) change

On 21 November 2019, the Authority published their final decision on the Targeted Charging Review (TCR) and issued Directions to NGESO to raise changes to the charging methodology to give effect to that final decision. This includes, among other changes, the removal of generation residual, which will take effect from April 2021.

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

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

Due to this TGR change, revenue collected from generators (via wider tariffs and local tariffs) will be much higher compared to 2020/21. In this forecast, generation revenue is forecast at £813.7m, an increase of £438.8m from £374.9m for 2020/21.

Exchange Rate

The exchange rate for 2021/22 was taken from the Economic and Fiscal Outlook, and will remains unchanged from August forecast, in line with the CUSC methodology. The value is €1.210793 /£.

Generation Output

The forecast output of generation has stayed the same at 222.8TWh. This figure is the average of the four scenarios in 20202 Future Energy Scenarios publication and will remain unchanged in Final tariffs.

Error Margin

The error margin remains unchanged from August forecast at 20.8%.

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

Table 16 Generation and demand revenue proportions

		2021/22 Tariffs		
Code	**Revenue**	**March**	**August**	**Draft**
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50	2.50
y	Error Margin	16.0%	20.8%	20.8%
ER	Exchange Rate (€/£)	1.12	1.21	1.21
MAR	Total Revenue (£m)	3,053.1	3,048.6	3,410.2
GO	Generation Output (TWh)	199.8	222.8	222.8
	Wider locational generator Revenue (£m)	403.0	382.3	366.4
	Charges on assets required for connection (£m)	445.6	462.0	449.3
G	% of revenue from generation	26.9%	27.1%	23.9%
D	% of revenue from demand	73.1%	72.9%	76.1%
G.R	Revenue recovered from generation (£m)	820.6	826.4	813.7
D.R	Revenue recovered from demand (£m)	2,232.6	2,222.2	2,596.5

19. Charging bases for 2020/21

Generation

The forecast generation charging base is less than contracted TEC. It excludes interconnectors, which are not chargeable, and generation that we do not expect to be chargeable during the charging year due to closure, termination or delay in connection. It also includes any generators that we believe may increase their TEC.

We are unable to break down our best view of generation as some of the information used to derive it could be commercially sensitive.

The generation charging base is 71.7GW due and based on our internal view of what generation we expect to connect in 2021/22.

Demand

Our forecasts of HH demand, NHH demand and embedded generation have been updated based on the latest available metering data. The impact of demand suppression due to COVID-19 has been reviewed further for the demand charging bases in the Draft Tariffs. Modelling inputs and assumptions will continue to be updated and reviewed in the run up to the final tariffs being published in January.

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

- Historical gross metered demand and embedded export volumes (August 2014-October 2020)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation

Overall, we assume that recent historical trends in steadily declining demand volumes will continue due to several factors, including the growth in distributed generation and “behind the meter” microgeneration. But as a result of the increase in electric vehicles and heat pumps, demand will begin to gradually increase again in future years. This is also in line with the FES analysis.

Table 17 Charging bases

Charging Bases	2021/22 Tariffs March	August	Draft
Generation (GW)	70.7	76.9	71.7
NHH Demand (4pm-7pm TWh)	24.0	24.4	24.6
Net Charging			
Total Average Net Triad (GW)	43.2	42.8	43.3
HH Demand Average Net Triad (GW)	12.6	11.6	12.3
Gross charging			
Total Average Gross Triad (GW)	50.0	50.2	50.0
HH Demand Average Gross Triad (GW)	19.4	18.9	19.0
Embedded Generation Export (GW)	6.8	7.3	6.7

20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast, we have used the final version of the 2020/21 ALFs, based upon data from 2014/15 to 2018/19. ALFs are explained in more detail in Appendix E of this report, and the full list of power station ALFs are available on the National Grid ESO website.[8]

The draft ALFs will be published by 30th November 2020 for comments. The ALFs will be finalised and published in January and incorporated in the final tariffs.

21. Generation and demand residuals

Under the existing CUSC methodology, the residual element of tariffs is calculated using the formulae below.

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

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

Where

- R_G is the generation residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation (the G/D split percentage)
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from generation locational tariffs (£m), including wider zonal tariffs and project-specific local tariffs
- B_G is the generator charging base (GW)

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

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

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

under CMP317/327, which seeks to ensure ongoing compliance with European Regulation by establishing which charges are, and are not, in scope of that range.

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

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

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

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[9] and phased residual.

Under the TDR, Ofgem also decided on some changes to the demand residual tariffs to apply in 2022, 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 2022, they have not been included in this forecast.

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

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

[9] Avoided Grid Supply Point Infrastructure Credit

Table 18 Residual components calculation

Component		2021/22 Tariffs March	August	Draft
G	Proportion of revenue recovered from generation (%)	26.9%	12.0%	23.9%
D	Proportion of revenue recovered from demand (%)	73.1%	88.0%	76.1%
R	Total TNUoS revenue (£m)	3,053.1	3,048.6	3,410.2
Generation Residual				
R_G	Generator residual tariff (£/kW)	- 0.37	- 0.23	- 0.03
Z_G	Revenue recovered from the wider locational element of generator tariffs (£m)	403.0	382.3	366.4
O	Revenue recovered from offshore local tariffs (£m)	408.2	426.9	422.7
L_G	Revenue recovered from onshore local substation tariffs (£m)	19.5	19.6	11.4
S_G	Revenue recovered from onshore local circuit tariffs (£m)	17.9	15.6	15.2
B_G	Generator charging base (GW)	76.8	76.9	71.7
Gross Demand Residual				
R_D	Demand residual tariff (£/kW)	46.8	46.6	54.3
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	- 92.4	- 99.2	- 104.5
EE	Amount to be paid to Embedded Export Tariffs (£m)	17.2	13.6	15.1
B_D	Demand Gross charging base (GW)	50.0	50.2	50.0

5

Sensitivities to change

Purpose

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

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

1. Treatment of revenue adjustments in the charging
2. Inclusion of congestion management in the EU cap
3. Revenue forecast sensitivity
4. Gen Cap Sensitivity
5. Security factors sensitivity
6. Expansion Constant & Factors Sensitivity

Caveats

The charging year 2021/22 is the first year of RIIO2 price control period, and a few TNUoS parameters are yet to be finalised. In addition, the methodology is subject to changes including TCR and other ongoing CUSC modification proposals. All tariffs in this section are to illustrate mathematically how tariffs may evolve. In presenting certain sensitivities under certain CUSC mod options, it does not infer about our view of the future, likelihoods of certain scenarios or changes to policy.

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

Sensitivity analysis

22. Treatment of revenue adjustments in the charging methodology

CUSC modification CMP344 is proposing that revenue adjustments associated with actual costs incurred and costs saved for a Transmission Licensee that occur within price control periods from unforeseen or unforeseeable events, including Income Adjusting Events (IAEs), are recovered from Transmission Users by adjusting the Demand Transmission Residual. The current methodology for revenue adjustments from unforeseen or unforeseeable events for OFTOs is to include the cost in the Offshore Local Tariffs across the next price control period.

The consultation for this modification was closed on 23 November[10] and proposes this modification will be implemented in April 2021, for next year's tariffs.

We have carried out a sensitivity analysis including Ofgem approved revenue adjustments from unforeseen and unforeseeable events, which included two such events, totalling a revenue of £2.8m. The base included this revenue in the Offshore Local Tariffs spread across the next 5 years of the RIIO2 price control period.

The below table shows the impact on tariffs.

[10] https://www.nationalgrideso.com/document/179091/download

Table S1 Impact on wider tariffs due to the inclusion of CMP344

		2021/22 Base Case	2021/22 CMP344 Sensitivity	Change
OFTO Local Revenue (£m)		422.69	422.26	- 0.430132
Revenue from Generation (£m)		813.71	813.28	- 0.430132
Revenue from Demand (£m)		2,596.96	2,599.77	2.811000
Generation Residual	£/kW	- 0.027640	- 0.027640	- 0.000000
Average Generation Tariff*	£/kW	11.351149	11.345149	- 0.006000
Average HH demand tariff	£/kW	52.460812	52.525658	0.064846
Demand Residual	£/kW	54.342512	54.407358	0.064846
Average NHH demand tariff	p/kWh	6.563620	6.571785	0.008165
Average EET tariff	£/kW	2.272481	2.272481	0.000000

*N.B These generation tariffs include local tariffs

Table S2 Impact on the Offshore Local Tariffs due to the inclusion of CMP344

Offshore Generator	Tariff Component (£/kW)			Change from base case (£/kW)		
	Substation	Circuit	ETUoS	Substation	Circuit	ETUoS
Barrow	8.847343	46.675227	1.159010	-	-	-
Burbo Bank	11.057328	21.346582	-	-	-	-
Dudgeon	16.213542	25.417361	-	-	-	-
Galloper	16.549490	26.155193	-	-	-	-
Greater Gabbard	16.455306	38.045116	-	-	-	-
Gunfleet	19.239008	17.730507	3.313933	-	-	-
Gwynt Y Mor	17.844372	17.710590	-	- 0.190882	- 0.183448	-
Humber Gateway	12.188327	27.939147	-	- 0.306977	- 0.671508	-
Lincs	16.957830	66.640797	-	-	-	-
London Array	11.475403	39.308601	-	-	-	-
Ormonde	27.175448	50.773900	0.404625	-	-	-
Race Bank	9.794833	27.170573	-	-	-	-
Robin Rigg	- 0.583944	33.842704	10.842987	-	-	-
Robin Rigg West	- 0.583944	33.842704	10.842987	-	-	-
Sheringham Shoal	25.429358	29.935070	0.650700	-	-	-
Thanet	19.382584	36.292362	0.873685	-	-	-
Walney 1	23.47605	46.90995	-	-	-	-
Walney 2	21.84251	44.42657	-	-	-	-
Walney 3	10.06170	20.35939	-	-	-	-
Walney 4	10.06170	20.35939	-	-	-	-
West of Duddon Sands	8.89648	44.31827	-	-	-	-
Westermost Rough	18.28621	31.09982	-	-	-	-

The inclusion of revenue adjustments from unforeseen and unforeseeable events would decrease OFTO revenue by £0.4m due to removing these adjustments made over the 5-year price control. The inclusion of these revenue adjustments would increase the demand residual by £2.8m in 2021/22. This would cause the demand residual to increase by £0.06/kW.

Please note there are several claims that are currently waiting for approval which may increase the amount of revenue adjustment that is being included in the demand residual.

23. Inclusion of congestion management in the EU cap

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

We are aware that the definition of congestion management costs and whether it should be included in the calculation for the generator charges EU cap were discussed at the CMP317/327 working group and it is with the Authority for decision. To help the industry to understand the implications of including congestion management cost in the TNUoS charges, we have provided a sensitivity analysis for 2021/22 illustrating its impact.

Based on the workgroup discussion around the definition and using the published Balancing Services Use of System (BSUoS) charge forecast[11] and publication of actual BSUoS costs for YTD[12].

For this sensitivity, we have assumed that congestion management costs include the following, which are estimated to total £547.6m for 2021/22.

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

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

Table S3 Impact of the inclusion of congestion management costs in the EU cap

		2021/22 Base Case	2021/22 Congestion Management Sensitivity	Change
Generation Residual	£/kW	- 0.027640	- 7.666583	- 7.638943
Average Generation Tariff*	£/kW	11.351149	3.712207	- 7.638943
Average HH demand tariff	£/kW	52.460812	63.416751	10.955939
Demand Residual	£/kW	54.342512	65.298452	10.955940
Average NHH demand tariff	p/kWh	6.563620	7.943205	1.379585
Average EET tariff	£/kW	2.272481	2.272481	0.000000
Revenue from Generation	£m	813.71	266.11	- 547.597908
Revenue from Demand	£m	2,596.53	3,144.13	547.597908

*N.B These generation tariffs include local tariffs

The table above shows that the inclusion of the assumed congestion management costs would significantly decrease the amount of revenue collected from generation, a reduction of £547.6m. This would decrease the generation residual from £-0.03/kW to £-7.67/kW. This in turn increases the amount of revenue to be collected from demand users which increases the demand residual by £10.96/kW. The EET is not impacted.

24. Revenue forecast sensitivity

Based on TOs' data, the total TNUoS revenue for 2021/22 would be £3.4bn (an Increase of ~£362m from August forecast). Having consulted the industry at the transmission charging methodology forum (TCMF), we have undertaken a sensitivity analysis by applying an annuity factor as per CMA's recent decision on water utilities' price control financial parameters. The sensitivity shows a reduction of £386m in total revenue across the three onshore TOs, subjecting to a list of high-level assumptions. Due to commercial sensitivity of onshore TOs' revenue forecast, it is not possible to test whether the underlying assumptions used in this sensitivity analysis were correct, however this sensitivity illustrates the possible magnitude of change in revenue if using different rate of return.

[11] https://data.nationalgrideso.com/backend/dataset/c0376ed7-3205-4fe2-9496-28496f1f287a/resource/5b608dfa-bc94-4a6f-aa0c-ff2a4cd0b10e/download/monthly-bsuos-forecast-summary-13112020.csv

[12] https://data.nationalgrideso.com/backend/dataset/c0376ed7-3205-4fe2-9496-28496f1f287a/resource/3e087f00-6a64-4380-9d77-bb31c5f8ae32/download/monthly-bsuos-actual-summary-13112020.csv

Table S4 Revenue forecast sensitivity

	NGET Base Revenue (£m)	Other NGET revenue items (£m)*	SPT Base Revenue (£m)	Other SPT revenue items (£m)*	SHETL Base Revenue (£m)	Other SHETL revenue items (£m)*	Other ESO revenue items (£m)**	Total (£m)
Base case (£m)	1961.8	-41.9	378.2	12.4	541.7	-2.0	560.0	3410.2
Assumption on financial parameters***	ESO assumes that onshore TOs based their revenue forecast on the same annuity and overhead factors as in RIIO-T1 (5.81%+ 1.8%). The sensitivity analysis uses an alternative annuity factor (4.79%) which is in line with CMA's decision on water utilities price control, and same overhead factor (1.8%) as in RIIO-T1							
Revenue Sensitivity (£m)	1698.9	-41.9	327.5	12.4	469.1	-2.0	560.0	3024.0
Variation (£m)	-262.9	0.0	-50.7	0.0	-72.6	0.0	0.0	-386.2

Note:

* Onshore TOs' other revenue items include pass-through (business rate, licence fee etc.), output incentives and other miscellaneous items, minus pre-vesting charge

** ESO's other revenue items include OFTO revenue, interconnector adjustment, network innovation competition (NIC), and other miscellaneous items

*** The sensitivity analysis is based on the following assumptions -

1. Assuming "other revenue items" in onshore TOs' revenue breakdown, remain the same as in the August forecast.

2. Assuming generic asset life of 50 years

3. Assuming onshore TOs' base revenue figures reflect regulated asset base only and is proportional to the total of (annuity factor + overhead factor).

25. Gen cap sensitivity (GOS)

Under CMP317/327, there are various definitions of Generator Only Spurs (GOS). In this forecast (and previous quarterly forecasts), we assume the definition in the original proposal. To illustrate the likely impacts on tariffs if an alternative definition is chosen, we have undertaken a sensitivity using the "narrowest" definition of GOS. This definition can be found in the draft legal texts in CMP339 - Consequential changes for CMP317/327 (TCR).

Onshore Generator Only Spurs (WACM2 of CMP339):

"In terms of an onshore generator, a spur consists of (a) an onshore substation (the Onshore Local Substation); and (b) underground cables, or overhead line that is not shared with demand, or another generator, which run from the Onshore Local Substation to an Onshore Substation, from where electricity can be transmitted towards its ultimate users."

Under this definition, generation revenue is reduced by £2.83m, and the non-locational adjustment element (shown as "residual" in tariff tables) will be slightly more negative (by 0.04/kW), in order to maintain the average generation tariffs within the € [0,2.50] range.

Table S5 Generation revenue breakdown and adjustment tariff (residual) under gen cap GOS sensitivity

	Peak Security (£m)	Year Round Shared (£m)	Year Round Not Shared (£m)	Residual (£m)	Onshore Local Circuit (£m)	Onshore Local Substation (£m)	Offshore Local (£m)	Total (£m)	Generation adjustment factor (residual) (£/kW)
Base case	109.0	109.2	148.3	-2.0	15.2	11.4	422.7	813.7	-0.027640
GOS sensitivity	109.0	109.2	148.3	-4.8	12.7	11.0	422.7	810.9	-0.067091
Variation	0.0	0.0	0.0	-2.8	-2.4	-0.4	0.0	-2.8	-0.039450

26. Security factor sensitivity

Following the 5-year view in August, we have re-calculated the Locational Onshore Security Factor. The value is currently 1.8, and the new value is around 1.7555. In this forecast, we have rounded the new number to one decimal place, in line with the accuracy of the current value. However, we are running a consultation on the approach to finalise the value.[13] In this section, we have updated the tables in our consultation letter, using the Draft tariffs.

Table S6 Demand tariffs under security factor at 2d.p. (SF=1.76)

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	21.454043	2.840242	0.000000
2	Southern Scotland	30.406702	3.853056	0.000000
3	Northern	42.589884	5.210601	0.000000
4	North West	49.203725	6.159754	0.000000
5	Yorkshire	49.865507	6.057063	0.000000
6	N Wales & Mersey	50.624480	6.142103	0.000000
7	East Midlands	53.609540	6.723347	1.476834
8	Midlands	55.146319	7.029331	3.013613
9	Eastern	55.471330	7.395494	3.338624
10	South Wales	57.430524	6.571053	5.297818
11	South East	57.967552	7.860002	5.834846
12	London	60.389612	6.334292	8.256906
13	Southern	60.067426	7.646027	7.934720
14	South Western	62.888119	8.579926	10.755413

[13] https://www.nationalgrideso.com/document/180741/download

Table S7 Generation tariffs under security factor at 2d.p. (SF=1.76)

Zone	Zone Name	Tariffs (£/kW)				Example tariffs for a generator of each technology type		
		System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.139437	19.913375	18.906466	0.000000	35.195310	38.976603	26.871816
2	East Aberdeenshire	3.162051	10.510472	18.906466	0.000000	26.695601	30.476895	23.110655
3	Western Highlands	3.854210	18.183520	18.195770	0.000000	32.957642	36.596796	25.469178
4	Skye and Lochalsh	-0.602230	18.183520	19.976366	0.000000	29.925679	33.920952	27.249774
5	Eastern Grampian and Tayside	4.642908	13.415803	15.344176	0.000000	27.650891	30.719726	20.710497
6	Central Grampian	4.285430	14.348370	16.414734	0.000000	28.895913	32.178860	22.154082
7	Argyll	2.653087	12.411813	25.075740	0.000000	32.643129	37.658277	30.040465
8	The Trossachs	3.770403	12.411813	14.150080	0.000000	25.019917	27.849933	19.114805
9	Stirlingshire and Fife	2.675011	10.967509	12.921110	0.000000	21.785906	24.370128	17.308114
10	South West Scotlands	2.962297	11.319605	13.192732	0.000000	22.572167	25.210713	17.720574
11	Lothian and Borders	2.929709	11.319605	6.531796	0.000000	17.210830	18.517189	11.059638
12	Solway and Cheviot	2.532332	7.629916	7.318295	0.000000	14.490901	15.954560	10.370261
13	North East England	3.356007	5.905974	4.419811	0.000000	11.616635	12.500597	6.782201
14	North Lancashire and The Lakes	2.492842	5.905974	1.254210	0.000000	8.220989	8.471831	3.616600
15	outh Lancashire, Yorkshire and Humb	3.803444	2.404514	0.349126	0.000000	6.006356	6.076181	1.310932
16	North Midlands and North Wales	3.178060	0.867422	0.000000	0.000000	3.871998	3.871998	0.346969
17	South Lincolnshire and North Norfolk	1.315505	1.555689	0.000000	0.000000	2.560056	2.560056	0.622276
18	Mid Wales and The Midlands	1.630226	1.794246	0.000000	0.000000	3.065623	3.065623	0.717698
19	Anglesey and Snowdon	4.805524	1.010675	0.000000	0.000000	5.614064	5.614064	0.404270
20	Pembrokeshire	7.461738	-6.322078	0.000000	0.000000	2.404076	2.404076	-2.528831
21	South Wales & Gloucester	3.422229	-6.658466	0.000000	0.000000	-1.904544	-1.904544	-2.663386
22	Cotswold	2.282147	3.527311	-8.482950	0.000000	-1.682364	-3.378954	-7.072026
23	Central London	-3.692985	3.527311	-5.529666	0.000000	-5.294869	-6.400802	-4.118742
24	Essex and Kent	-3.343043	3.527311	0.000000	0.000000	-0.521194	-0.521194	1.410924
25	Oxfordshire, Surrey and Sussex	-0.988620	-1.881891	0.000000	0.000000	-2.494133	-2.494133	-0.752756
26	Somerset and Wessex	-2.254034	-3.320635	0.000000	0.000000	-4.910542	-4.910542	-1.328254
27	West Devon and Cornwall	-2.533072	-8.338170	0.000000	0.000000	-9.203608	-9.203608	-3.335268

Table S8 Demand tariffs under security factor at 8d.p. (SF= 1.75547656)

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	21.551513	2.853145	0.000000
2	Southern Scotland	30.481163	3.862492	0.000000
3	Northern	42.633033	5.215880	0.000000
4	North West	49.229875	6.163028	0.000000
5	Yorkshire	49.889956	6.060033	0.000000
6	N Wales & Mersey	50.646978	6.144833	0.000000
7	East Midlands	53.624366	6.725207	1.478906
8	Midlands	55.157196	7.030718	3.011735
9	Eastern	55.481372	7.396833	3.335911
10	South Wales	57.435530	6.571626	5.290070
11	South East	57.971178	7.860493	5.825717
12	London	60.387013	6.334020	8.241552
13	Southern	60.065655	7.645801	7.920195
14	South Western	62.879098	8.578695	10.733638

Table S9 Generation tariffs under security factor at 8d.p. (SF= 1.75547656)

		Tariffs (£/kW)				Example tariffs for a generator of each technology type		
Zone	Zone Name	System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	4.128798	19.862195	18.857873	0.000000	35.104852	38.876427	26.802751
2	East Aberdeenshire	3.153924	10.483458	18.857873	0.000000	26.626989	30.398563	23.051256
3	Western Highlands	3.844304	18.136786	18.149004	0.000000	32.872936	36.502737	25.403718
4	Skye and Lochalsh	-0.600682	18.136786	19.925024	0.000000	29.848766	33.833771	27.179738
5	Eastern Grampian and Tayside	4.630975	13.381323	15.304739	0.000000	27.579825	30.640772	20.657268
6	Central Grampian	4.274415	14.311493	16.372545	0.000000	28.821645	32.096154	22.097142
7	Argyll	2.646269	12.379913	25.011292	0.000000	32.559233	37.561491	29.963257
8	The Trossachs	3.760713	12.379913	14.113713	0.000000	24.955614	27.778356	19.065678
9	Stirlingshire and Fife	2.668135	10.939321	12.887901	0.000000	21.729913	24.307493	17.263629
10	South West Scotlands	2.954684	11.290512	13.158825	0.000000	22.514154	25.145919	17.675030
11	Lothian and Borders	2.922180	11.290512	6.515009	0.000000	17.166597	18.469599	11.031214
12	Solway and Cheviot	2.525823	7.610306	7.299486	0.000000	14.453657	15.913554	10.343608
13	North East England	3.347382	5.890795	4.408451	0.000000	11.586779	12.468469	6.764769
14	North Lancashire and The Lakes	2.486435	5.890795	1.250986	0.000000	8.199860	8.450057	3.607304
15	outh Lancashire, Yorkshire and Humb	3.793669	2.398334	0.348228	0.000000	5.990919	6.060564	1.307562
16	North Midlands and North Wales	3.169892	0.865193	0.000000	0.000000	3.862046	3.862046	0.346077
17	South Lincolnshire and North Norfolk	1.312124	1.551691	0.000000	0.000000	2.553477	2.553477	0.620676
18	Mid Wales and The Midlands	1.626037	1.789635	0.000000	0.000000	3.057745	3.057745	0.715854
19	Anglesey and Snowdon	4.793173	1.008078	0.000000	0.000000	5.599635	5.599635	0.403231
20	Pembrokeshire	7.442560	-6.305829	0.000000	0.000000	2.397897	2.397897	-2.522332
21	South Wales & Gloucester	3.413434	-6.641353	0.000000	0.000000	-1.899648	-1.899648	-2.656541
22	Cotswold	2.276282	3.518245	-8.461148	0.000000	-1.678040	-3.370270	-7.053850
23	Central London	-3.683494	3.518245	-5.515454	0.000000	-5.281261	-6.384352	-4.108156
24	Essex and Kent	-3.334451	3.518245	0.000000	0.000000	-0.519855	-0.519855	1.407298
25	Oxfordshire, Surrey and Sussex	-0.986079	-1.877054	0.000000	0.000000	-2.487722	-2.487722	-0.750822
26	Somerset and Wessex	-2.248241	-3.312101	0.000000	0.000000	-4.897922	-4.897922	-1.324840
27	West Devon and Cornwall	-2.526562	-8.316740	0.000000	0.000000	-9.179954	-9.179954	-3.326696

27. Expansion Constant and related factors sensitivity

As part of the RIIO-2 parameter refresh the expansion constant (EC) is to be reset for 2021/22 tariffs, as well as the corresponding expansion factors (EFs). As reported in our previous forecast we are seeing a significant increase in the EC for RIIO-2 vs the RIIO-1 EC. There were also significant changes in the EFs that potentially didn't reflect expectation. An urgent Modification was raised by the ESO at the end of October to stabilise the EC & EFs for 2021/22 so that further investigation / review of methodology and data provision can be undertaken.

The below tables and charts show the impact on Draft Tariffs with updated values for the RIIO-2 EC&EF's vs Draft Tariffs base case (Stabilised RIIO-1 EC&EFs).

Demand Summary

Table S10 Draft Tariffs Demand Summary – RIIO-2 Updated EC&EF's vs Base Case

HH Tariffs	2021/22 Draft (Base Case)	2021/22 Draft (EC&F RIIO-2 Update)	Change
Average Tariff (£/kW)	52.460812	52.628548	0.167736
Residual (£/kW)	54.342512	55.895627	1.553115
EET	**2021/22 Draft (Base Case)**	**2021/22 Draft (EC&F RIIO-2 Update)**	**Change**
Average Tariff (£/kW)	2.272481	3.215122	0.942641
Phased residual (£/kW)	0.000000	0.000000	0.000000
AGIC (£/kW)	2.282952	2.282952	0.000000
Embedded Export Volume (GW)	6.658889	6.658889	0.000000
Total Credit (£m)	15.132202	21.409142	6.276940
NHH Tariffs	**2021/22 Draft (Base Case)**	**2021/22 Draft (EC&F RIIO-2 Update)**	**Change**
Average (p/kWh)	6.563620	6.570210	0.006590

HH Demand Tariffs

Table S11 Draft Tariffs HH Demand Summary – RIIO-2 Updated EC&EF's vs Base Case

Zone	Zone Name	2021/22 Draft (£/kW)	2021/22 Draft (£/kW) (EC&F RIIO-2 Update)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	20.631769	0.000000	-20.631769	1.553115
2	Southern Scotland	29.787898	13.589573	-16.198325	1.553115
3	Northern	42.247971	35.596862	-6.651109	1.553115
4	North West	49.012126	47.339100	-1.673026	1.553115
5	Yorkshire	49.688949	48.144849	-1.544100	1.553115
6	N Wales & Mersey	50.465171	49.499243	-0.965928	1.553115
7	East Midlands	53.518073	54.851803	1.333730	1.553115
8	Midlands	55.089779	57.316240	2.226461	1.553115
9	Eastern	55.422177	58.915563	3.493386	1.553115
10	South Wales	57.425898	60.788586	3.362688	1.553115
11	South East	57.975131	61.881059	3.905928	1.553115
12	London	60.452238	64.390360	3.938122	1.553115
13	Southern	60.122730	65.280455	5.157725	1.553115
14	South Western	63.007529	70.592401	7.584872	1.553115

Figure S1 Change in HH demand Tariffs - RIIO-2 Updated EC&EF's vs Base Case

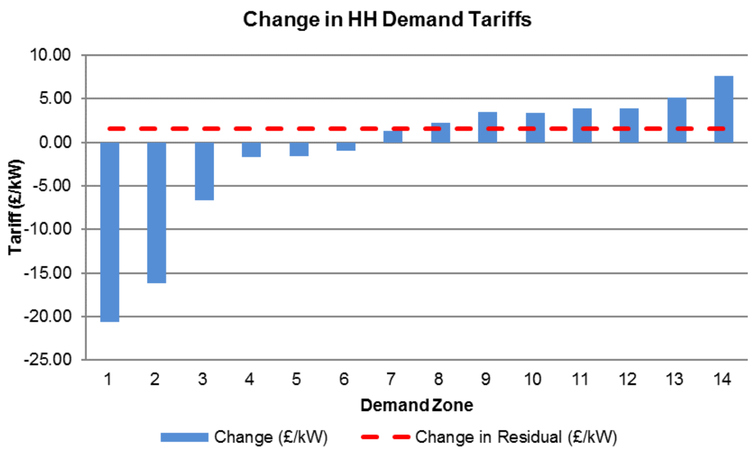


Table S12 Draft Tariffs Embedded Export – RIIO-2 Updated EC&EF's vs Base Case

Zone	Zone Name	2021/22 Draft (£/kW)	2021/22 Draft (£/kW) (EC&F RIIO-2 Update)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.000000	0.000000	0.000000
6	N Wales & Mersey	0.000000	0.000000	0.000000
7	East Midlands	1.458513	1.239128	-0.219385
8	Midlands	3.030219	3.703565	0.673346
9	Eastern	3.362617	5.302887	1.940270
10	South Wales	5.366338	7.175911	1.809573
11	South East	5.915571	8.268383	2.352812
12	London	8.392678	10.777685	2.385007
13	Southern	8.063170	11.667780	3.604610
14	South Western	10.947969	16.979726	6.031757

Figure S2 Change in Embedded Export Tariffs - RIIO-2 Updated EC&EF's vs Base Case

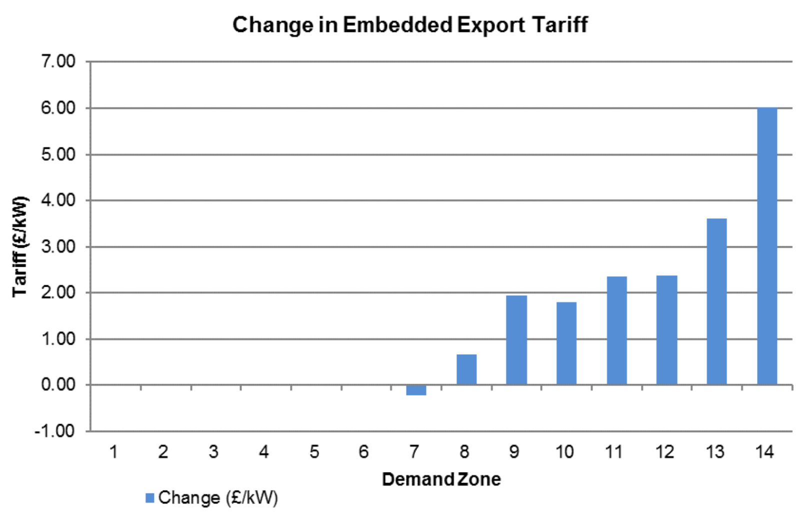
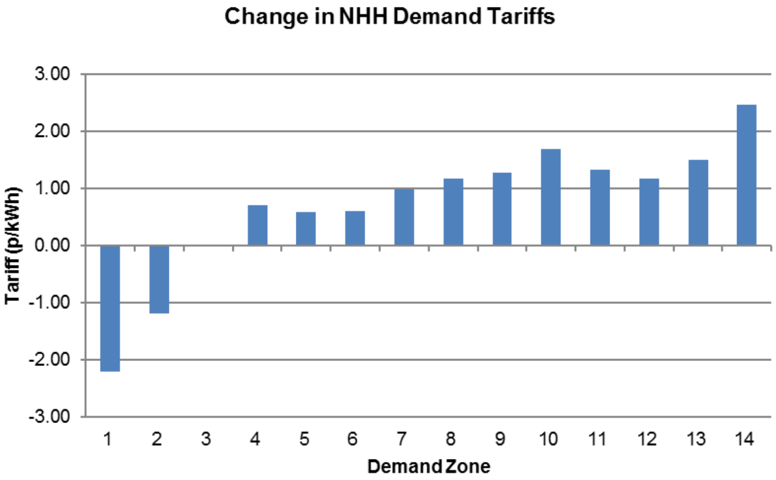


Table S13 Draft Tariffs NHH Demand – RIIO-2 Updated EC&EF's vs Base Case

Zone	Zone Name	2021/22 Draft (p/kWh)	2021/22 Draft (p/kWh) (EC&F RIIO-2 Update)	Change (p/kWh)
1	Northern Scotland	2.045854	-0.162748	-2.208602
2	Southern Scotland	2.913497	1.722034	-1.191463
3	Northern	4.357130	4.355049	-0.002081
4	North West	5.207812	5.926324	0.718512
5	Yorkshire	5.257421	5.848058	0.590637
6	N Wales & Mersey	5.393179	6.005582	0.612403
7	East Midlands	5.897278	6.879143	0.981865
8	Midlands	6.131826	7.305924	1.174098
9	Eastern	6.576802	7.854683	1.277881
10	South Wales	5.259660	6.955274	1.695614
11	South East	7.062878	8.390646	1.327768
12	London	5.580801	6.753932	1.173131
13	Southern	6.795285	8.309597	1.514312
14	South Western	7.157069	9.631033	2.473964

Figure S3 Change in NHH Demand Tariffs - RIIO-2 Updated EC&EF's vs Base Case



Generation Summary

Table S14 Draft Tariffs Generation Summary – RIIO-2 Updated EC&EF's vs Base Case

Generation Tariffs (£/kW)	2021/22 Draft	2021/22 Draft (EC&F RIIO-2 Update)	Change
Residual	-0.027640	-3.408831	-3.381190
Average Generation Tariff	11.351149	11.371708	0.020559

Table S15 Draft Tariffs Generation – RIIO-2 Updated EC&EF's

						Example tariffs for a generator of each technology type:		
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	7.036444	35.271266	33.685495	-3.408831	58.793022	65.530121	44.385170
2	East Aberdeenshire	4.690311	17.852517	33.685495	-3.408831	42.511890	49.248989	37.417671
3	Western Highlands	6.647819	32.370151	32.493597	-3.408831	55.129986	61.628706	42.032826
4	Skye and Lochalsh	-9.730408	32.370151	39.208484	-3.408831	44.123669	51.965366	48.747713
5	Eastern Grampian and Tayside	9.837533	23.956783	27.461522	-3.408831	47.563346	53.055650	33.635404
6	Central Grampian	7.745847	27.076512	31.042876	-3.408831	50.832526	57.041102	38.464650
7	Argyll	2.050994	22.281196	46.743996	-3.408831	53.862317	63.211116	52.247643
8	The Trossachs	6.238060	22.281196	25.435127	-3.408831	41.002287	46.089313	30.938774
9	Stirlingshire and Fife	4.272401	19.631385	23.180380	-3.408831	35.112982	39.749058	27.624103
10	South West Scotlands	4.845749	20.145980	23.577360	-3.408831	36.415590	41.131062	28.226921
11	Lothian and Borders	4.845649	20.145980	11.679691	-3.408831	26.897355	29.233293	16.329252
12	Solway and Cheviot	3.790439	13.206041	12.528128	-3.408831	20.968943	23.474569	14.401713
13	North East England	5.448131	10.356779	7.737628	-3.408831	16.514826	18.062351	8.471509
14	North Lancashire and The Lakes	4.035137	10.356779	1.456753	-3.408831	10.077132	10.368482	2.190634
15	South Lancashire, Yorkshire and Humber	6.181872	4.236419	0.622295	-3.408831	6.660012	6.784471	-1.091968
16	North Midlands and North Wales	5.164898	1.496647		-3.408831	2.953385	2.953385	-2.810172
17	South Lincolnshire and North Norfolk	1.810564	2.269497		-3.408831	0.217331	0.217331	-2.501032
18	Mid Wales and The Midlands	2.362423	2.533204		-3.408831	0.980155	0.980155	-2.395549
19	Anglesey and Snowdon	7.738386	1.950308		-3.408831	5.889801	5.889801	-2.628708
20	Pembrokeshire	12.627238	-10.449411		-3.408831	0.858878	0.858878	-7.588595
21	South Wales & Gloucester	5.549438	-10.740783		-3.408831	-6.452019	-6.452019	-7.705144
22	Cotswold	3.817271	4.078568	-12.639287	-3.408831	-6.440135	-8.967993	-14.416691
23	Central London	-5.541144	4.078568	-7.358544	-3.408831	-11.573956	-13.045665	-9.135948
24	Essex and Kent	-5.117544	4.078568		-3.408831	-5.263521	-5.263521	-1.777404
25	Oxfordshire, Surrey and Sussex	-2.132700	-3.436477		-3.408831	-8.290713	-8.290713	-4.783422
26	Somerset and Wessex	-3.845890	-5.753115		-3.408831	-11.857213	-11.857213	-5.710077
27	West Devon and Cornwall	-4.504774	-14.678882		-3.408831	-19.656711	-19.656711	-9.280384

Figure S4 Draft Tariffs Generation Zonal Profile – RIIO-2 Updated EC&EF's vs Base Case

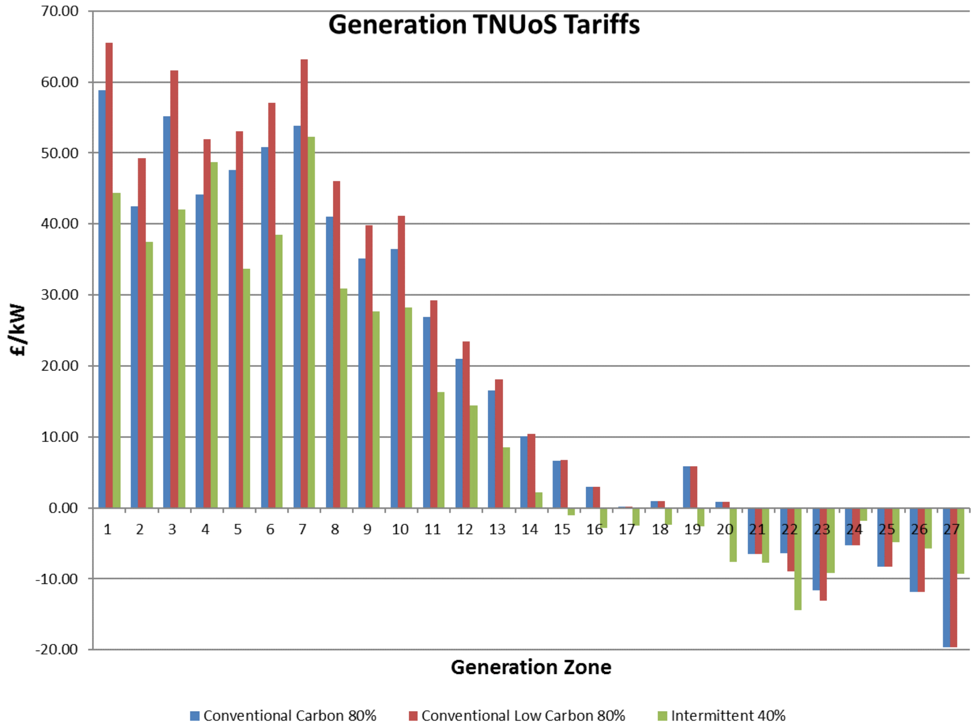
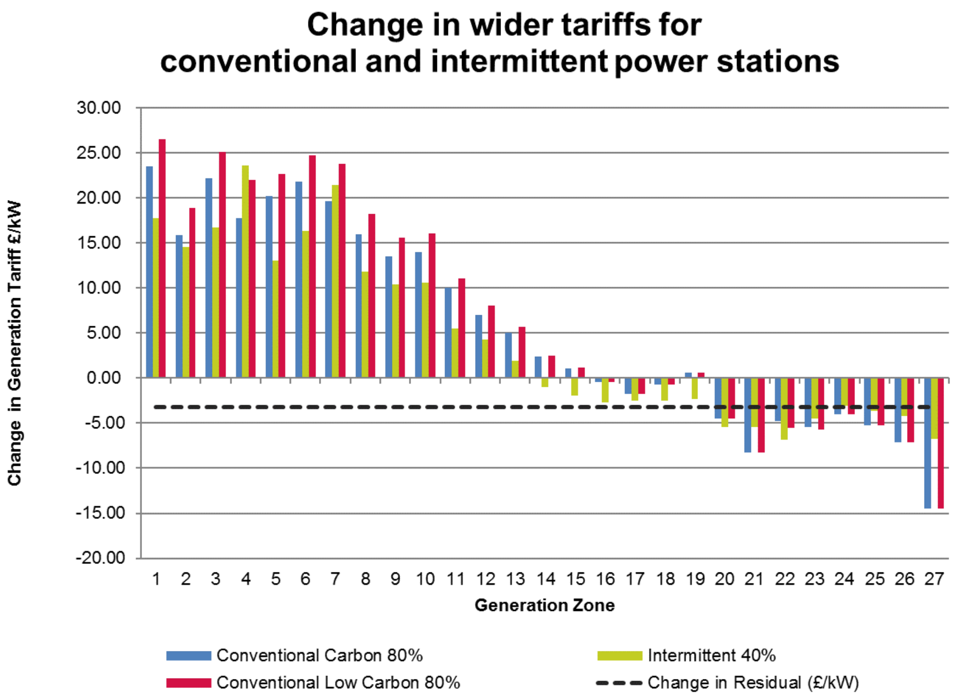


Table S16 Draft Tariffs Generation – RIIO-2 Updated EC&EF's vs Base Case

		Wider Generation Tariffs (£/kW)									
		Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			
Zone	Zone Name	2021/22 Draft (£/kW)	2021/22 Draft (£/kW) (EC&F RIIO-2 Update)	Change (£/kW)	2021/22 Draft (£/kW)	2021/22 Draft (£/kW) (EC&F RIIO-2 Update)	Change (£/kW)	2021/22 Draft (£/kW)	2021/22 Draft (£/kW) (EC&F RIIO-2 Update)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	35.274428	58.793022	23.518594	39.047686	65.530121	26.482435	26.669580	44.385170	17.715590	-3.176079
2	East Aberdeenshire	26.632864	42.511890	15.879025	30.406122	49.248989	18.842866	22.893911	37.417671	14.523760	-3.176079
3	Western Highlands	32.942153	55.129986	22.187833	36.583199	61.628706	25.045507	25.287880	42.032826	16.744947	-3.176079
4	Skye and Lochalsh	26.389325	44.123669	17.734344	30.011005	51.965366	21.954361	25.191049	48.747713	23.556665	-3.176079
5	Eastern Grampian and Tayside	27.341760	47.563346	20.221586	30.446901	53.055650	22.608749	20.644432	33.635404	12.990972	-3.176079
6	Central Grampian	29.049413	50.832526	21.783113	32.378388	57.041102	24.662713	22.172202	38.464650	16.292448	-3.176079
7	Argyll	34.242806	53.862317	19.619510	39.466308	63.211116	23.744808	30.837805	52.247643	21.409838	-3.176079
8	The Trossachs	25.013958	41.002287	15.988329	27.892180	46.089313	18.197133	19.111406	30.938774	11.827368	-3.176079
9	Stirlingshire and Fife	21.593847	35.112982	13.519135	24.221321	39.749058	15.527737	17.238955	27.624103	10.385148	-3.176079
10	South West Scotlands	22.408012	36.415590	14.007578	25.083813	41.131062	16.047249	17.612373	28.226921	10.614548	-3.176079
11	Lothian and Borders	16.877376	26.897355	10.019978	18.195474	29.233293	11.037819	10.823854	16.329252	5.505398	-3.176079
12	Solway and Cheviot	13.963422	20.968943	7.005521	15.443995	23.474569	8.030574	10.095532	14.401713	4.306181	-3.176079
13	North East England	11.478354	16.514826	5.036472	12.388323	18.062351	5.674029	6.546961	8.471509	1.924548	-3.176079
14	North Lancashire and The Lakes	7.685003	10.077132	2.392128	7.928241	10.368482	2.440242	3.213305	2.190634	-1.022671	-3.176079
15	South Lancashire, Yorkshire and Humber	5.575947	6.660012	1.084065	5.646358	6.784471	1.138113	0.873377	-1.091968	-1.965346	-3.176079
16	North Midlands and North Wales	3.368012	2.953385	-0.414628	3.368012	2.953385	-0.414628	-0.124780	-2.810172	-2.685392	-3.176079
17	South Lincolnshire and North Norfolk	2.000066	0.217331	-1.782735	2.000066	0.217331	-1.782735	-0.021509	-2.501032	-2.479523	-3.176079
18	Mid Wales and The Midlands	1.723622	0.980155	-0.743466	1.723622	0.980155	-0.743466	0.108472	-2.395549	-2.504021	-3.176079
19	Anglesey and Snowdon	5.322926	5.889801	0.566876	5.322926	5.889801	0.566876	-0.260080	-2.628708	-2.368628	-3.176079
20	Pembrokeshire	5.314758	0.858878	-4.455880	5.314758	0.858878	-4.455880	-2.195841	-7.588595	-5.392755	-3.176079
21	South Wales & Gloucester	1.799154	-6.452019	-8.251173	1.799154	-6.452019	-8.251173	-2.242097	-7.705144	-5.463048	-3.176079
22	Cotswold	-1.664316	-6.440135	-4.775819	-3.440793	-8.967993	-5.527200	-7.586895	-14.416691	-6.829796	-3.176079
23	Central London	-6.160795	-11.573956	-5.413161	-7.347505	-13.045665	-5.698160	-4.638061	-9.135948	-4.497887	-3.176079
24	Essex and Kent	-1.278850	-5.263521	-3.984671	-1.278850	-5.263521	-3.984671	1.295488	-1.777404	-3.072892	-3.176079
25	Oxfordshire, Surrey and Sussex	-3.083429	-8.290713	-5.207284	-3.083429	-8.290713	-5.207284	-1.095790	-4.783422	-3.687632	-3.176079
26	Somerset and Wessex	-4.685198	-11.857213	-7.172015	-4.685198	-11.857213	-7.172015	-1.493397	-5.710077	-4.216680	-3.176079
27	West Devon and Cornwall	-5.221758	-19.656711	-14.434953	-5.221758	-19.656711	-14.434953	-2.546327	-9.280384	-6.734056	-3.176079

Figure S5 Draft Tariffs Generation Zonal Profile – RIIO-2 Updated EC&EF's vs Base Case



Tools and supporting information

Further information

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

Charging webinars

We will be hosting a webinar on this Draft TNUoS tariffs for 2021/22 on 10 December 2020. The webinar will be published on our website and a communication will be sent out when it is available.

Charging model copies available

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

Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website under 2021/22 forecasts:

https://www.nationalgrideso.com/tnuos

Contact Us

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

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

Our contact details

Email: TNUoS.queries@nationalgrideso.com

A

Appendix A: Background to TNUoS charging

Background to TNUoS charging

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

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

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

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

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

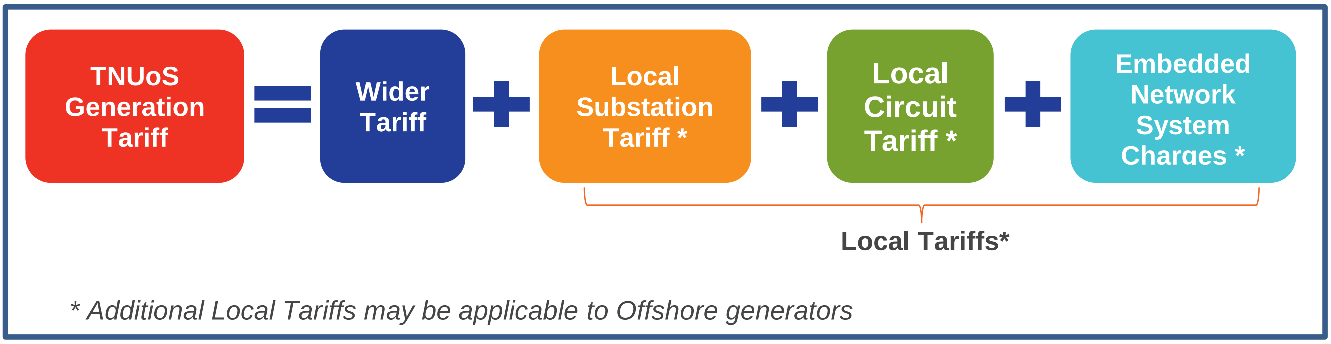
Generation charging principles

Transmission connected generators (and embedded generators with TEC >= 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.

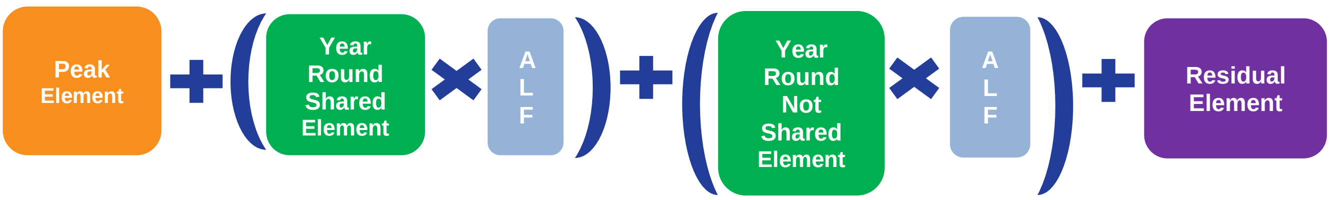
*Embedded network system charges are only payable by offshore generators whose host OFTO are not directly connected to the onshore transmission network and are not applicable to all generators.

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.

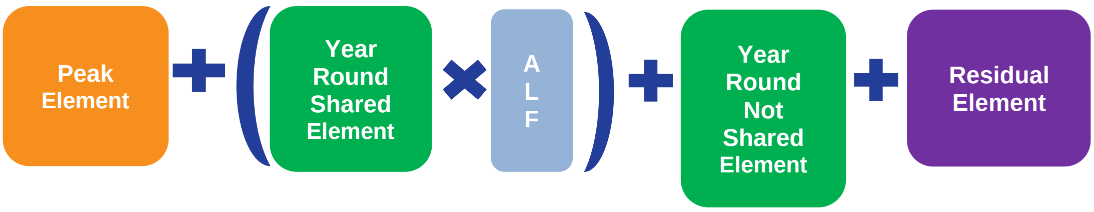
Conventional Carbon Generators

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



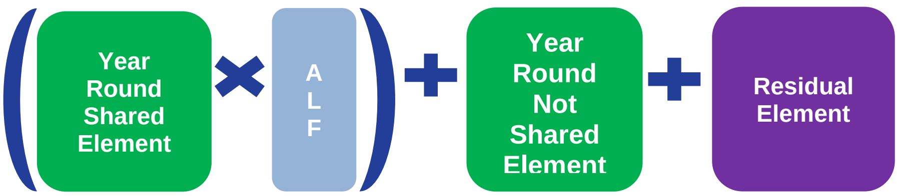
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

The ALFs used in these tariffs are listed from page 60.

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

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

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

Local substation tariffs

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

Local onshore substation tariffs are set at the start of each TO financial regulatory period and increased by RPI each year.

Local circuit tariffs

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

Embedded network system charges

If a generator is not connected directly to the transmission network, they need to have a BEGA[14] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS[15] charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

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

Click here to find out more about DNO regions.

Offshore local tariffs

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

Billing

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

The calculation for TNUoS generator monthly liability is as follows:

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

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

TNUoS charges are billed each month for the month ahead.

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

[15] Distribution network Use of System charges

Generators with negative TNUoS tariffs

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

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

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

Demand charging principles

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

HH gross demand tariffs

HH gross demand tariffs are made up of locational and residual charges which are currently charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year.[16] They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data are available, via the NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website[17].

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[18].

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

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

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

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

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

NHH demand tariffs

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

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

TCR changes on Transmission Demand Residual (TDR) tariffs

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

B

Appendix B: Changes and proposed changes to the charging methodology

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

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

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

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

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

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

The Small Generator Discount

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

Table 19 Summary of in-flight CUSC modification proposals

Name	Title	Effect of proposed change	Possible implementation
CMP280	Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users	Remove demand residual charges from generation and storage	April 2022 or beyond, if approved
CMP316	TNUoS Arrangements for Co-located Generation Sites	Develop a cost-reflective TNUoS arrangement for generation sites with multiple technology types	April 2022 or beyond, if approved
CMP317 & CMP327	Identification and exclusion of Assets Required for Connection when setting TNUoS charges	Removal of revenue linked to "generator only spurs" from the calculation of generation revenue cap under the EU rules, and setting generation residual tariff to 0	April 2021, if approved
CMP324 & CMP325	Generation Re-zoning	Revise TNUoS generation zoning methodology	Approved and implemented in this forecast
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.	April 2021, if approved
CMP353	Stabilising the Expansion Constant and non-specific Onshore Expansion Factors from 1st April 2021	To stabilise the locational signal at the start of the RIIO-2 period at the RIIO-1 value plus relevant inflation in each charging year until such time as the effect of any change in the locational signal can be better understood.	April 2021, if approved

C

Appendix C: Breakdown of locational HH and EE tariffs

Breakdown of HH and EET locational tariffs

The table below shows the locational demand tariff elements used in the gross HH demand tariff and the EET, and the associated changes from the August forecast to the Draft tariffs.

Table 20 Demand HH locational tariffs

Demand Zone		2021/22 August		2021/22 Draft		Changes	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	- 1.559501	- 29.948864	- 2.065765	- 31.644978	- 0.506264	- 1.696114
2	Southern Scotland	- 2.564159	- 21.500595	- 2.680634	- 21.873981	- 0.116475	- 0.373386
3	Northern	- 3.241022	- 8.248344	- 3.292852	- 8.801690	- 0.051830	- 0.553346
4	North West	- 2.185331	- 3.174417	- 2.307845	- 3.022541	- 0.122514	0.151876
5	Yorkshire	- 2.329010	- 1.700130	- 2.510350	- 2.143213	- 0.181340	- 0.443083
6	N Wales & Mersey	- 2.476767	- 0.782259	- 2.395844	- 1.481497	0.080923	- 0.699238
7	East Midlands	- 2.269741	1.927424	- 2.374727	1.550288	- 0.104986	- 0.377136
8	Midlands	- 2.160602	3.073794	- 1.926371	2.673638	0.234231	- 0.400156
9	Eastern	1.375979	0.067569	1.312462	- 0.232797	- 0.063517	- 0.300366
10	South Wales	- 6.270157	4.990677	- 3.943770	7.027156	2.326387	2.036479
11	South East	4.133843	0.486328	3.707807	- 0.075189	- 0.426035	- 0.561516
12	London	5.761676	0.939686	5.131544	0.978182	- 0.630132	0.038497
13	Southern	2.129560	3.947512	1.985722	3.794496	- 0.143838	- 0.153016
14	South Western	- 0.409925	5.785214	1.486458	7.178559	1.896382	1.393345

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

Table 21 Breakdown of the EET

Demand Zone		2021/22 August		2021/22 Draft		Changes	
		Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)	Locational (£/kW)	AGIC (£/kW)
1	Northern Scotland	- 31.50837	2.28788	- 33.71074	2.28295	- 2.20238	- 0.00493
2	Southern Scotland	- 24.06475	2.28788	- 24.55461	2.28295	- 0.48986	- 0.00493
3	Northern	- 11.48937	2.28788	- 12.09454	2.28295	- 0.60518	- 0.00493
4	North West	- 5.35975	2.28788	- 5.33039	2.28295	0.02936	- 0.00493
5	Yorkshire	- 4.02914	2.28788	- 4.65356	2.28295	- 0.62442	- 0.00493
6	N Wales & Mersey	- 3.25903	2.28788	- 3.87734	2.28295	- 0.61832	- 0.00493
7	East Midlands	- 0.34232	2.28788	- 0.82444	2.28295	- 0.48212	- 0.00493
8	Midlands	0.91319	2.28788	0.74727	2.28295	- 0.16593	- 0.00493
9	Eastern	1.44355	2.28788	1.07966	2.28295	- 0.36388	- 0.00493
10	South Wales	- 1.27948	2.28788	3.08339	2.28295	4.36287	- 0.00493
11	South East	4.62017	2.28788	3.63262	2.28295	- 0.98755	- 0.00493
12	London	6.70136	2.28788	6.10973	2.28295	- 0.59164	- 0.00493
13	Southern	6.07707	2.28788	5.78022	2.28295	- 0.29685	- 0.00493
14	South Western	5.37529	2.28788	8.66502	2.28295	3.28973	- 0.00493

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

The AGIC is the Avoided GSP Infrastructure Credit, which is indexed by average May to October RPI each year. The AGIC has been reviewed for the next priced control.

D

Appendix D: Locational demand profiles

Locational demand profiles

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

The gross half-hourly (HH) demand forecast has increased slightly to 19.0GW and the non-half-hourly (NHH) demand forecast has increased to 24.6TWh. Embedded export volumes have decreased and are forecast to be 6.7GW.

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

Table 22 Demand profile

Zone	Zone Name	2021/22 August					2021/22 Draft				
		Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	167	1,465	435	0.76	1,375	122	1,436	437	0.76	1,025
2	Southern Scotland	2,314	3,335	1,191	1.66	577	1,977	3,308	1,201	1.66	630
3	Northern	2,046	2,497	1,032	1.18	487	2,037	2,487	1,030	1.19	411
4	North West	2,881	3,931	1,470	1.95	441	2,183	3,900	1,445	1.96	369
5	Yorkshire	4,002	3,748	1,541	1.79	783	4,062	3,741	1,547	1.81	671
6	N Wales & Mersey	2,841	2,558	1,008	1.24	625	2,568	2,544	1,017	1.26	533
7	East Midlands	5,445	4,581	1,745	2.22	585	5,059	4,573	1,757	2.25	504
8	Midlands	4,445	4,155	1,560	2.01	268	4,198	4,137	1,551	2.03	262
9	Eastern	5,672	6,268	2,013	3.10	620	5,301	6,305	2,120	3.14	772
10	South Wales	1,642	1,778	799	0.84	419	1,821	1,761	788	0.85	366
11	South East	3,217	3,830	1,155	1.94	354	3,400	3,803	1,147	1.96	326
12	London	5,171	4,082	2,167	1.83	127	4,657	4,094	2,173	1.83	130
13	Southern	7,684	5,384	2,014	2.61	394	6,553	5,358	2,004	2.64	413
14	South Western	2,167	2,544	735	1.31	259	2,412	2,534	737	1.32	246
Total		**49,694**	**50,156**	**18,866**	**24.43**	**7,313**	**46,350**	**49,982**	**18,954**	**24.64**	**6,659**

E

Appendix E: Annual Load Factors

Specific ALFs

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

For the purposes of this forecast, we have used the final version of the 2020/21 ALFs, which were calculated using Transmission Entry Capacity, metered output and Final Physical Notifications from charging years 2014/15 to 2018/19. The draft ALFs to be used for 2021/22 are being calculated using the data from charging years 2015/16 to 2019/20 and will be published on our website by 30th November. Generators which were commissioned after 1 April 2017, including new Generators expected to commission during 2021/22, will use Generic ALFs until data available after three full years of operation.

The specific and generic ALFs that will apply to 2021/22 TNUoS Tariffs, will be published by 30 November 2020 for feedback, and will be finalised by end December. The specific and generic ALFs for 2020/21 tariffs, as used in this forecast, are published here.

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

Generic ALFs for 2020/21

Table 23 Generic ALFs for 2020/21

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

Includes OCGTs (Open Cycle Gas Turbine generating plant).

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

These Generic ALFs are calculated in accordance with CUSC 14.15.110.

2020 draft ALFs (including generic and station-specific ALFs) to be used for charging year 2021/22, will be published on 30th November.

F

Appendix F: Contracted generation changes since the August forecast

The table below shows the TEC changes notified between the August forecast and the 2021/22 draft tariffs. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

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

Table 24 Contracted generation changes

Power Station	MW Change	Node	Generation Zone
Nemo Link (correction)	-1020	RICH40	24
Abedare	10	UPPB21	21
Aberthaw	-1560	ABTH20	21
Burwell (Tertiary)	-49.9	BURW40	18
Capenhurst 275KV Substation	49.9	CAPE20	16
Exeter (Tertiary)	-49.9	EXET40	26
Fallago Rig 2	-41.4	FALL40	11
Kirkby (Tertiary)	-49.9	KIBY20	15
North Killingholme Power Project	-540	KILL40	15
Oldbury (Tertiary)	-49.9	OLDB4A	18
Seabank (Tertiary)	-49.9	SEAB40	22
Sellindge (Tertiary)	-49.9	SELL40	24
Thurrock	600	TILB20	24
Tralorg Wind Farm	20	MAHI20	10
Bramford (Tertiary PP)	-49.9	BRFO40	18

The contracted generation used in the Transport model is now fixed, using the TEC register as of 31 October 2020, as stated by the CUSC 14.15.6.

G

Appendix G Transmission company revenues

Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs have updated us with their revenue forecast for year 2021/22, however as 2021/22 is the start of RIIO-T2 price control, there are significant uncertainties about the revenue forecast, before Ofgem makes final decision on onshore TOs' RIIO-T2 business plan (planned for December).

In addition to TOs' revenue, there are some pass-through items that are to be collected by NGESO via TNUoS charges, including the Network Innovation Competition (NIC) fund, contribution made from IFA, and site-specific adjustments by TOs etc. these figures are relatively small compared to TOs revenue, and will be finalised by January Final tariffs.

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

Notes:

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

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

NGESO TNUoS revenue pass-through items forecasts

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

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

Table 25 NGESO revenue breakdown

£m Nominal	2021/22 TNUoS Revenue March Forecast	2021/22 TNUoS Revenue August Forecast	2021/22 TNUoS Revenue Nov Draft
National Grid Electricity Transmission			
Price controlled revenue	*1,754.9*	*1,753.7*	*1,949.7*
Less income from connections		*29.8*	*29.8*
NGET Income from TNUoS	**1,754.9**	**1,723.9**	**1,919.9**
Scottish Power Transmission			
Price controlled revenue	*389.5*	*384.2*	*410.1*
Less income from connections	*12.7*	*12.7*	*19.5*
SPT Income from TNUoS	**376.7**	**371.5**	**390.6**
SHE Transmission			
Price controlled revenue	*377.5*	*383.4*	*542.6*
Less income from connections	*3.4*	*3.4*	*2.9*
SHE Income from TNUoS	**374.0**	**380.0**	**539.7**
National Grid Electricity System Operator			
Other Pass-through from TNUoS	**17.4**	**17.5**	**14.4**
Offshore (plus interconnector contribution / al	**529.9**	**555.8**	**545.6**
Total to Collect from TNUoS	**3,053.1**	**3,048.6**	**3,410.2**

Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) have updated us with their revenue forecast for year 2021/22, based largely on their RIIO-T2 business plan that are yet to be approved by Ofgem in December. As a result, the revenue forecast is highly indicative, and may change significantly following Ofgem's Final Determination on RIIO-T2.

Offshore Transmission Owner revenue & Interconnector adjustment

The Offshore Transmission Owner revenue to be collected via TNUoS for 2021/22 is forecast to be £545.6m.

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. In addition, there are some CACM cost recovery that may be included in 2021/22 TNUoS revenue, as a one-off adjustment, and the total amount of interconnector adjustment will be finalised by January.

Table 26 NGESO revenue pass-through breakdown

Term	NGESO TNUoS Other Pass-Through		
	March Forecast	August Forecast	Nov Draft
Embedded Offshore Pass-Through (OFETt)	0.6	0.6	0.6
Network Innovation Competition (NICFt)	13.9	13.9	13.9
ESO Network Innovation Allowance (NIAt)	3.0	3.0	-
Offshore Transmission Revenue (OFTOt) and Interconnec	529.9	555.8	545.6
Financial facility (FINt)		-	-
Site Specific Charges Discrepancy (DISt)		-	-
Termination Sums (TSt)		-	-
NGET revenue pas-through (NGETTOt)*	1,754.9	1,723.9	1,919.9
SPT revenue pass-through (TSPt)	376.7	371.5	390.6
SHETL revenue pass-through (TSHt)	374.0	380.0	539.7
Total	**3,053.1**	**3,048.6**	**3,410.2**

Table 27 NGET revenue breakdown

2021/22 Revenue Description		Licence Term	National Grid Electricity Transmission		
Regulatory Year			March Forecast	August Forecast	Nov Draft
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 1,585.1		
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (393.9)		
RPI True Up	A3	TRUt	£ (1.1)		
RPI Forecast	A4	RPIFt	1.420		
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 1,690.0**	**£ 1,688.8**	**£ 1,961.8**
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ 38.1		
Temporary Physical Disconnection	B2	TPDt	£ 4.8		
Inter TSO Compensation	B4	ITCt	£ (2.8)		
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ 40.2**	**£ 40.2**	**£ -**
Financial Incentive for Timely Connections Output	C5	-CONADJt			
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ 17.2	£ 17.2	
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ 17.2**	**£ 17.2**	**£ -**
Network Innovation Allowance	D	NIAt	£ 7.6	£ 7.6	
Future Environmental Discretionary Rewards	F	EDRt			
Transmission Investment for Renewable Generation	G	TIRGt			
Correction Factor	-K	-K			£ (12.1)
Financial Facility	FINt	FINt			
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 1,754.9**	**£ 1,753.7**	**£ 1,949.7**
Pre-vesting connection charges	S1		£ -	£ 29.7	£ 29.7
Rental Site	S2		£ -	£ 0.1	£ 0.1
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 1,754.9**	**£ 1,723.9**	**£ 1,919.9**

Table 28 SPT revenue breakdown

2021/22 Revenue Description		Licence Term	Scottish Power Transmission		
Regulatory Year			**March Forecast**	**August Forecast**	**Nov Draft**
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 261.9		
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (8.5)		
RPI True Up	A3	TRUt	£ (2.1)		
RPI Forecast	A4	RPIFt	£ 1.4		
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 356.9**	**£ 351.6**	**£ 378.2**
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ 4.1	£ 4.1	
Temporary Physical Disconnection	B2	TPDt	£ -		
Inter TSO Compensation	B4	ITCt			
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ 4.1**	**£ 4.1**	
Financial Incentive for Timely Connections Output	C5	-CONADJt			
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ 3.4		
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ 3.4**	**£ 3.4**	
Network Innovation Allowance	D	NIAt	£ -		
Future Environmental Discretionary Rewards	F	EDRt	£ -		
Transmission Investment for Renewable Generation	G	TIRGt	£ 32.5	£ 32.5	£ 31.9
Correction Factor	-K	-K	£ (7.4)	£ (7.4)	
Financial Facility	FINt	FINt			
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 389.5**	**£ 384.2**	**£ 410.1**
Pre-vesting connection charges	S1		£ 12.7	£ 12.7	£ 19.46
Rental Site	S2				
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 376.7**	**£ 371.5**	**£ 390.6**

Table 29 SHETL revenue breakdown

2021/22 Revenue Description		Licence Term	SHE Transmission		
Regulatory Year			March Forecast	July Forecast	Nov Draft
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	£ 273.4		
Price Control Financial Model Iteration Adjustment	A2	MODt	£ (8.2)		
RPI True Up	A3	TRUt	£ -		
RPI Forecast	A4	RPIFt	£ 1.4		
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**£ 376.6**	**£ 382.50**	
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	£ -		
Temporary Physical Disconnection	B2	TPDt	£ -		
Inter TSO Compensation	B4	ITCt			
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**£ -**		
Financial Incentive for Timely Connections Output	C5	-CONADJt			
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	£ -		
Outputs Incentive Revenue [C=C1+C2+C3]	**C**	**OIPt**	**£ -**		
Network Innovation Allowance	D	NIAt	£ 0.9	£ 0.9	
Future Environmental Discretionary Rewards	F	EDRt	£ -		
Transmission Investment for Renewable Generation	G	TIRGt	£ -		
Correction Factor	-K	-K	£ -		
Financial Facility	FINt	FINt			
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**£ 377.5**	**£ 383.4**	**£ 542.64**
Pre-vesting connection charges	S1		£ 3.4	£ 3.4	£ 2.90
Rental Site	S2				
TNUoS Collected Revenue [T=M-B5-P]	**T**		**£ 374.0**	**£ 380.0**	**£ 539.7**

Table 30 Offshore revenues

Offshore Transmission Revenue Forecast (£m)	26/11/2020								
Regulatory Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	Notes
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.6	6.7	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	8.2	8.4	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	15.1	15.3	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	9.3	9.4	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	14.9	15.1	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.9	23.4	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.9	14.1	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	31.6	32.1	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	44.3	44.5	Current revenues plus indexation
Thanet		17.5	15.7	19.5	18.6	19.2	19.7	20.7	Current revenues plus indexation
Lincs	78.9	25.6	26.7	27.2	28.2	29.2	29.7	30.0	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	18.9	26.4	Current revenues plus indexation
West of Duddon Sands			21.3	22.0	22.6	23.6	23.1	25.3	Current revenues plus indexation
Humber Gateway		35.3	29.3	9.7	12.1	12.5	11.3	13.0	Current revenues plus indexation
Westermost Rough				11.6	13.2	13.6	13.9	14.2	Current revenues plus indexation
Burbo Bank					34.3	13.1	12.8	14.1	Current revenues plus indexation
Dudgeon						18.7	19.2	19.6	Current revenues plus indexation
Race Bank							26.7	27.4	Current revenues plus indexation
Galloper								17.1	Current revenues plus indexation
Walney 3						66.0	37.8	13.5	Current revenues plus indexation
Walney 4								13.5	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2020/21							63.9	103.2	National Grid Forecast
Forecast to asset transfer to OFTO in 2021/22								38.7	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**260.8**	**265.5**	**317.9**	**390.6**	**443.8**	**545.6**	

Notes:

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

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

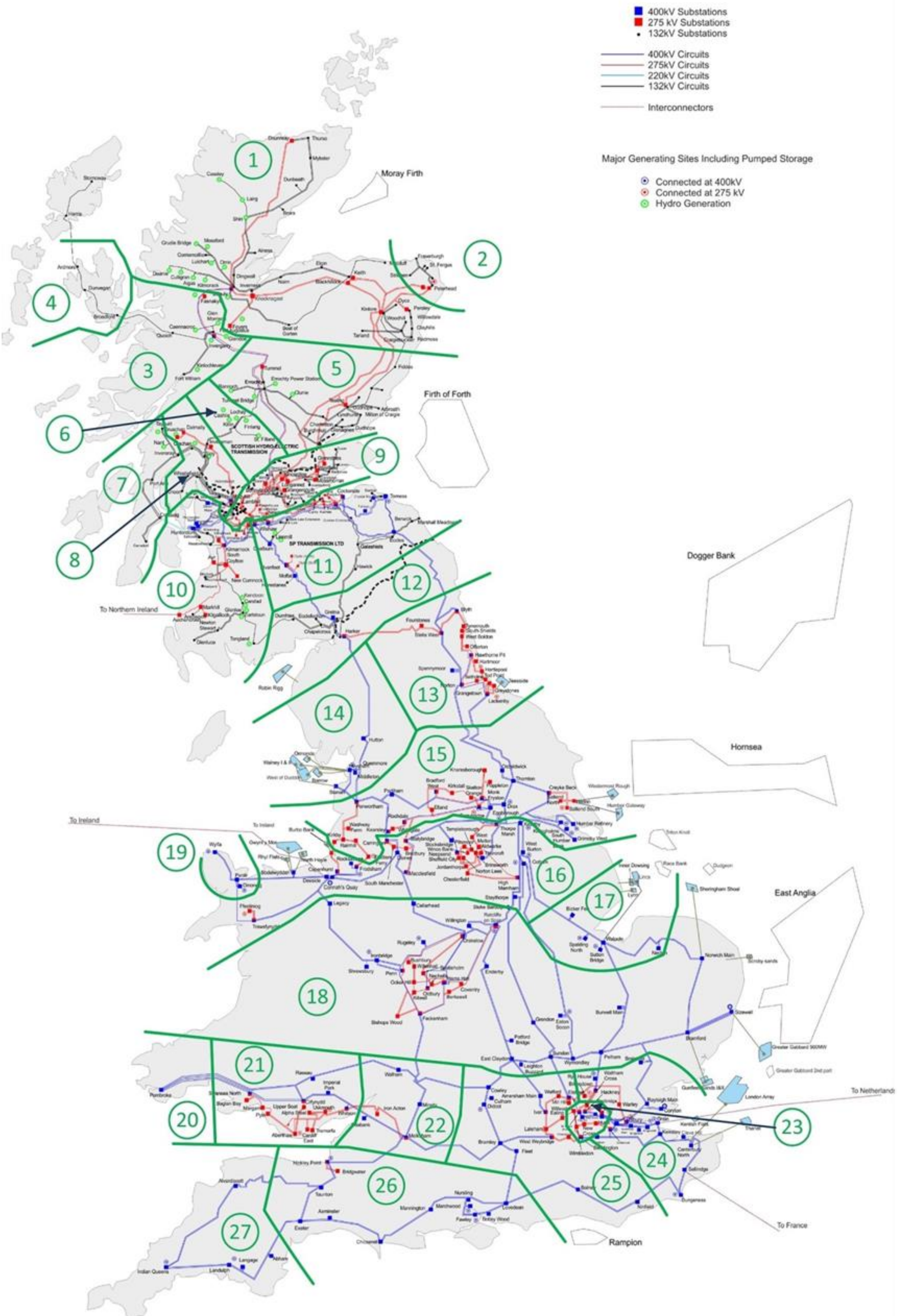
Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formulae are constructed

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

H

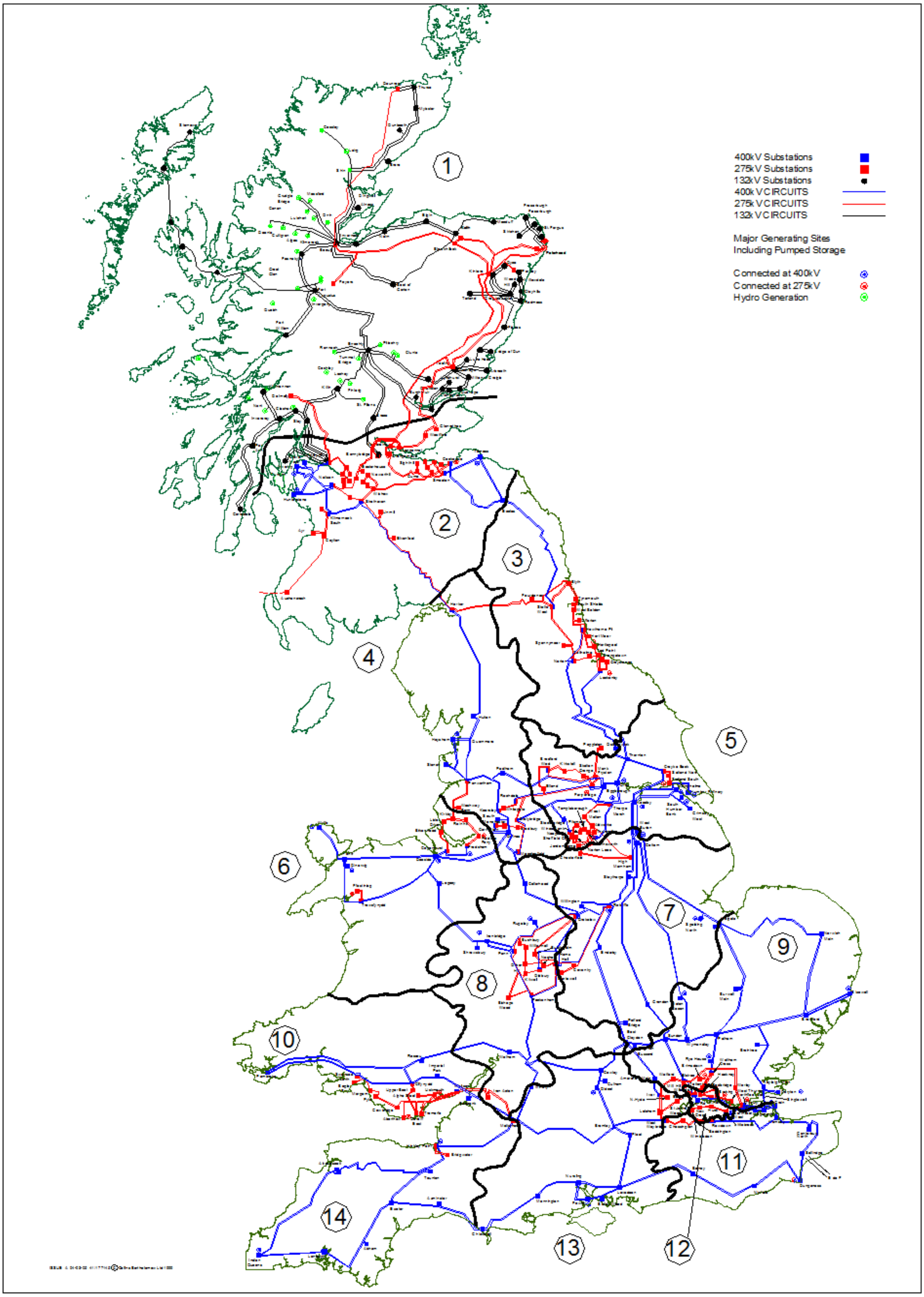
Appendix H: Generation zones map

Figure A2: GB Existing Transmission System



I

Appendix I: Demand zones map


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

Parameters affecting TNUoS tariffs

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

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

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