Forecast TNUoS Tariffs for 2019/20

April 2018

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This information paper provides National Grid's April Forecast Transmission Network Use of System (TNUoS) Tariffs for 2019/20, applicable to transmission connected Generators and Suppliers, effective from 1 April 2019.

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Executive Summary

This document contains the latest forecast of the Transmission Network Use of System (TNUoS) Tariffs for 2019/20. These tariffs will apply for the charging year starting 1 April 2019. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

The tariffs for 2019/20 were last forecast in our November 2017 Five-Year forecast. The next forecast will be in June 2018.

Total Revenues to be recovered

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,835.8m in 2019/20. This is £132.5m less than the November forecast, and £165.5m more than 2018/19. We will be revising this figure throughout the year and it will be confirmed in the final tariffs report.

Generation Tariffs

We forecast that generation tariffs will recover £431.8m. This is to ensure that average annual generation tariffs remain below the €2.5/MWh limit. This limit is set by European Commission Regulation (EU) No 838/2010 using the methodology defined in the CUSC. This figure has reduced by £11.7m compared to the November forecast, due to a revised exchange rate being published by the OBR[1]. The Error Margin applied in the G/D split calculation remains fixed at 21%.

The chargeable TEC for 2018/19, we forecast to be 71.7GW. This is a decrease of 2.1GW compared to the November forecast. We forecast the average generation tariff to be £6.02/kW. This is an increase of 1p/kW since the November forecast, and an increase of 4p/kW compared to 2018/19.

Demand Tariffs

We forecast the revenue to be recovered from demand tariffs to be £2,404m in 2019/20. This is a decrease of £122m compared to the November forecast.

We now have the system demand data for winter 2017/18, and have prepared a revised forecast of chargeable demand using our Monte Carlo model. We have also adjusted our forecast based on P339[2] which factors in the expected HH/NHH demand shift we are seeing during settlement.

We are forecasting a gross system peak of 51.3GW. This is a +0.1GW increase since the November forecast. Gross HH demand is forecast to be 18GW (-1.8GW) and NHH demand is forecast to be 25.5TWh (+2TWh). The switch from HH to NHH demand is due to P339.

The winter of 2017/18 saw high Embedded Export volumes at Triad of just short of 8GW, compared to 6.25GW in 2016/17. This has led us to update our forecast of Embedded Export volume for 2019/20 to 7.8GW (+1.7GW).

[1] *Office for Budget Responsibility, Economic and Fiscal Outlook, March 2018.* http://obr.uk/efo/economic-fiscal-outlook-march-2018/

[2] https://www.elexon.co.uk/mod-proposal/p339/

We now forecast that £111m will be payable through the Embedded Export Tariff (EET), compared to £82m in our November forecast.

The average forecast gross HH demand tariff is £49.35/kW. The average forecast EET is £14.30/kW. The average forecast NHH demand tariff is 6.38p/kWh. Our new forecast sees the average HH and NHH tariffs reduce since November by £1.81/kW and 0.57p/kWh. Due to change in locational demand tariffs and volumes, our forecast of the average EET has increased by £1.02/kW compared to November.

Drivers of changes to the Tariff forecast

The principal drivers for change between our April and November tariff forecast are:

- An increase in the forecast volume of Embedded Export.
- A lower total revenue forecast, primarily due to decreases in expected OFTO and National Grid ETO revenues.

Future Forecasts

In Appendix I we show how we intend to update the various parameters which affect charging in future forecasts. For our future forecasts, all parameters affecting both generation and demand tariffs may be updated.

In our next June forecast, we intend to fix the total revenue paid by generation. We also intend to fix the chargeable demand forecast. In the November forecast, the intention is for the locational tariffs to be finalised. The residual tariffs will vary until our Final tariffs in January 2019, as final allowed revenue is only provided to us in late January.

Small Generator Discount

The Small Generator Discount, is defined in National Grid's licence condition C13. This licence condition expires on 31 March 2019. Previously a discount was applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV.

From 2019/20, no discount will be applied to generator tariffs, and no rebate rates will be applied to demand tariffs.

Changes to the Charging Methodology which may affect 2019/20 tariffs

The Charging Methodology can be changed through modifications to the CUSC. There are several such proposals currently being considered. If approved, these may affect tariffs for 2019/20 onwards.

Judicial Review of CMP264/265

From 2018/19 the demand charging methodology changed to charge on Gross HH demand, with a credit for Embedded Export. This decision remains subject to judicial review. Hearings have taken place between 25th-27th April 2018 and a decision is pending.

If Ofgem's decision to approve the modification is quashed, then we may need to set tariffs for 2019/20 on the previous net methodology. This may also affect 2018/19 tariffs through a 'mid-year tariff change'

Other modifications

CMP251. A methodology to change the calculation of the total generation TNUoS revenue, and introduce ex-post reconciliation of generator charges to €2.50/MWh. This modification is pending Ofgem's decision.

CMP280. Seeks to charge Generator Users a new tariff for demand, which removes the liability for demand residual charges. A workgroup is currently considering this modification.

CMP286, CMP287 and CMP292. These modifications seek to fix elements of the charging methodology during the tariff setting process. This includes Allowed Revenue, parameters such as chargeable demand, and the methodology itself.

These modifications are discussed in more detail in Appendix A and are being considered by workgroups.

Other modifications may also be proposed which may affect tariffs from 2019/20.

Next forecast

Our next publication of 2019/20 TNUoS tariffs will be the June forecast.

The latest tariff forecast timetable can be found on our website.[3]

Feedback

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.

[3] *Our revised forecast publication timetable is available on our website:* http://www.nationalgrid.com/tnuos

Demand Tariffs

Tables 1, 2 and 3 show demand tariffs for Half-Hourly, Embedded Export and Non-Half-Hour metered demand.

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

Table 1: Summary of Demand tariffs

HH Tariffs	2019/20 - Initial	2019/20 April	Change
Average Tariff (£/kW)	51.161915	49.346251	-1.815664
Residual (£/kW)	52.133975	50.298596	-1.835379
EET	**2019/20 - Initial**	**2019/20 April**	**Change**
Average Tariff (£/kW)	13.275477	14.301062	1.025585
Phased residual (£/kW)	14.650000	14.650000	0.000000
AGIC (£/kW)	3.320000	3.320000	0.000000
Embedded Export Volume (GW)	6.143418	7.752808	1.609390
Total Credit (£m)	81.556808	110.873388	29.316579
NHH Tariffs	**2019/20 - Initial**	**2019/20 April**	**Change**
Average (p/kWh)	6.947702	6.374706	-0.572996

Table 2: Demand tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	19.737006	2.656788	0.000000
2	Southern Scotland	27.418724	3.589422	0.000000
3	Northern	39.892709	5.067577	7.564113
4	North West	46.722382	6.057879	14.393786
5	Yorkshire	47.014046	5.983781	14.685451
6	N Wales & Mersey	48.298681	6.089003	15.970085
7	East Midlands	50.452344	6.609453	18.123748
8	Midlands	51.752366	6.823196	19.423770
9	Eastern	52.491085	7.321247	20.162489
10	South Wales	48.660552	5.739832	16.331956
11	South East	55.225293	7.827031	22.896697
12	London	58.347780	6.188397	26.019184
13	Southern	56.468265	7.471902	24.139669
14	South Western	54.806629	7.650205	22.478033

Residual charge for demand:	£ 50.298596

Changes since the previous demand tariffs forecast

Since the implementation of CMP264/265 into the TNUoS methodology from the 2018/19 tariffs, the way in which HH demand is charged has changed. HH tariffs are charged on a gross basis instead of net. A separate Embedded Export Tariff payment is made to embedded generators which generate over triad periods.

The main drivers of change to this forecast compared to November includes the demand charging base update and changes to revenue.

Overall, the impact on average demand tariffs has varied, the average HH gross tariff is now £49.35/kW, and compared to the November forecast this has reduced by £1.81/kW, the NHH average tariff is now 6.37p/kWh, a slight decrease of 0.58p/kWh.

The average EET is £14.30/kW which has increased by £1.02/kW. Our forecast predicts that the increase in EET will result in an additional £29m to be paid to embedded generators/suppliers with the total payable now £111m. This is recovered through the demand tariffs. More information on the causes of specific zonal fluctuations is detailed in the HH and NHH sections below.

Gross half hourly demand tariffs

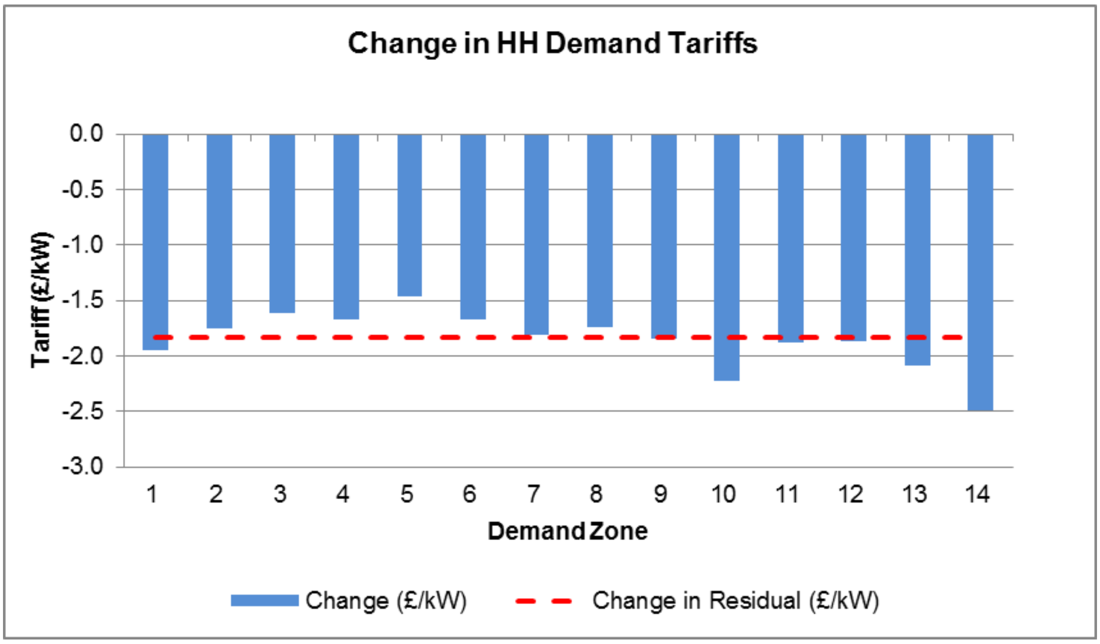
Table 3 and Figure 1 show the gross HH demand tariffs 2019/20 forecast.

Table 3 – Gross HH demand tariffs

Zone	Zone Name	2019/20 Initial (£/kW)	2019/20 April (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	21.687374	19.737006	-1.950368	-1.835379
2	Southern Scotland	29.168681	27.418724	-1.749957	-1.835379
3	Northern	41.500763	39.892709	-1.608054	-1.835379
4	North West	48.398977	46.722382	-1.676595	-1.835379
5	Yorkshire	48.473350	47.014046	-1.459304	-1.835379
6	N Wales & Mersey	49.966859	48.298681	-1.668178	-1.835379
7	East Midlands	52.258221	50.452344	-1.805877	-1.835379
8	Midlands	53.495056	51.752366	-1.742690	-1.835379
9	Eastern	54.333811	52.491085	-1.842726	-1.835379
10	South Wales	50.889819	48.660552	-2.229267	-1.835379
11	South East	57.105050	55.225293	-1.879757	-1.835379
12	London	60.210439	58.347780	-1.862659	-1.835379
13	Southern	58.553985	56.468265	-2.085720	-1.835379
14	South Western	57.299753	54.806629	-2.493124	-1.835379

The breakdown of the locational elements of these tariffs is shown in Appendix B.

Figure 1 - Gross HH demand tariffs



The average HH gross demand tariff of £49.35/kW represents a decrease of £1.81/kW, this is largely due to changes in the chargeable demand based on the 2017/18 triads. The level of gross HH chargeable demand is now 18GW, reducing by 1.8GW from November. The decrease in the average tariff can also be attributed to a reduction in the total revenue to be recovered.

Larger variations can be seen in zone 10 (South Wales), zone 13 (Southern) and zone 14 (South Western) which have decreased by £2.22/kW, £2.08/kW and £2.49/kW respectively. Elsewhere, further decreases can be seen across all zones and are also driven by the effect of both locational and residual changes. The key factors contributing to this include:

- A reduction in revenue to be recovered from demand.
- An increase in the EET credit.
- Locational tariff variations across zones due to TEC changes.

The residual element of the tariff has also decreased by £1.83/kW, this is primarily driven by a decrease in the total revenue forecast and offset by the increase in the embedded export revenue. This is due to the EET revenue being included within the HH demand residual as part of the total revenue to be recovered for demand. The level of embedded export revenue, which is calculated by multiplying the embedded export volume during triads with the associated zonal tariff, has a direct impact on HH demand tariffs.

Embedded export tariff

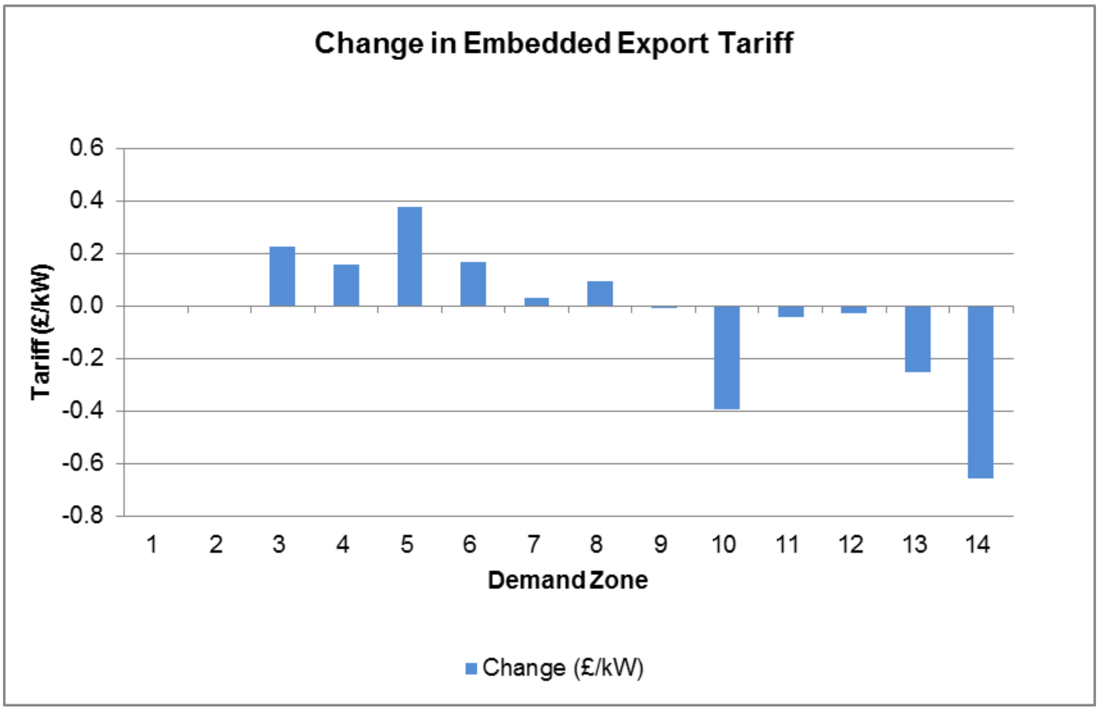
Table 4 and Figure 2 show the embedded export tariffs in the April 2019/20 forecast compared to the November forecast.

Table 4 – Embedded export tariffs

Zone	Zone Name	2019/20 Initial (£/kW)	2019/20 April (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	7.336788	7.564113	0.227325
4	North West	14.235002	14.393786	0.158784
5	Yorkshire	14.309375	14.685451	0.376076
6	N Wales & Mersey	15.802884	15.970085	0.167201
7	East Midlands	18.094246	18.123748	0.029502
8	Midlands	19.331081	19.423770	0.092689
9	Eastern	20.169836	20.162489	-0.007347
10	South Wales	16.725844	16.331956	-0.393888
11	South East	22.941075	22.896697	-0.044378
12	London	26.046464	26.019184	-0.027280
13	Southern	24.390010	24.139669	-0.250341
14	South Western	23.135778	22.478033	-0.657745

The breakdown of the locational elements of these tariffs is shown in Appendix B.

Figure 2 – Embedded Export Tariff



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

The average EET has increased by £1.02/kW and is now £14.30/kW, which is due to the level of forecasted embedded export volumes over triads increasing to 7.75GW. This has resulted in the total value of credit payable to embedded export volumes rising by £29m to £111m.

The slight variations in tariffs are driven by the locational tariff changes as previously described for the HH tariffs as the EET uses the same locational elements of peak and year round. The largest variations occurred in zones 3 (Northern) and 5 (Yorkshire) which have increased by £0.22/kW and £0.37/kW respectively, zone 10 (South Wales) and zone 14 (South Western) however have reduced by £0.39/kW and £0.65/kW.

As the level of the EET is determined by the locational elements of the HH tariff, the EET is lowest in zone 1 (£0/kW, tariff floored at £0/kW; the zone 1 locational tariff is £-30.56/kW), but where the locational element is at its highest in zone 12, the EET is £26.01/kW.

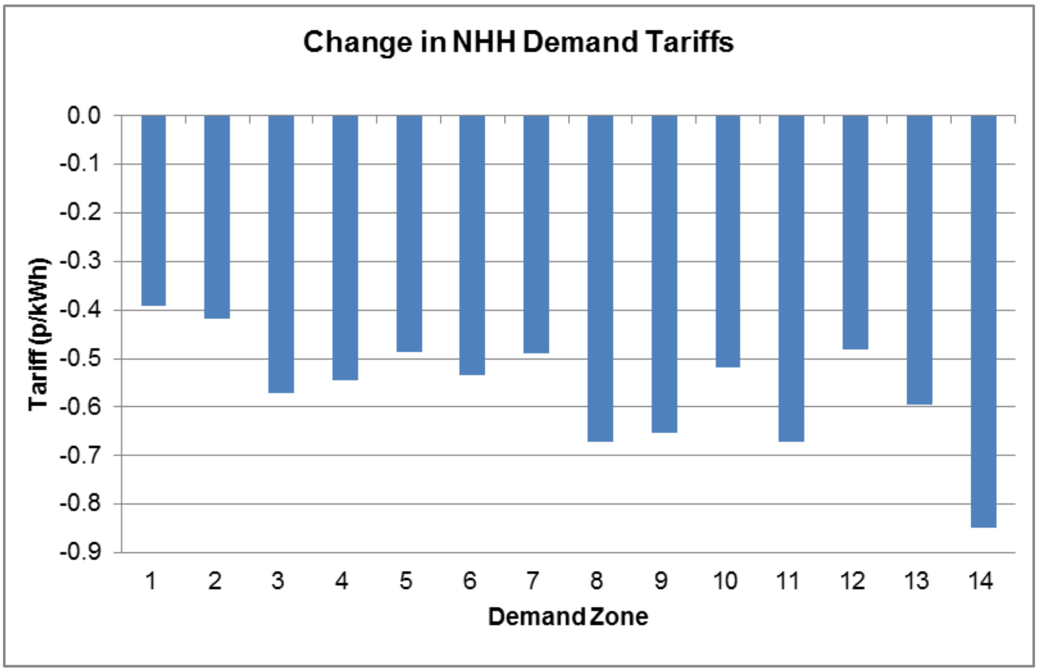
NHH demand tariffs

Table 5 and Figure 3 show the difference between the NHH demand tariffs forecast in November and this April 2019/20 forecast.

Table 5 - NHH demand tariff changes

Zone	Zone Name	2019/20 Initial (p/kWh)	2019/20 April (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.048118	2.656788	-0.391330
2	Southern Scotland	4.006678	3.589422	-0.417256
3	Northern	5.638348	5.067577	-0.570771
4	North West	6.601478	6.057879	-0.543599
5	Yorkshire	6.469700	5.983781	-0.485919
6	N Wales & Mersey	6.622207	6.089003	-0.533204
7	East Midlands	7.099223	6.609453	-0.489770
8	Midlands	7.495568	6.823196	-0.672372
9	Eastern	7.973654	7.321247	-0.652407
10	South Wales	6.257491	5.739832	-0.517659
11	South East	8.497337	7.827031	-0.670306
12	London	6.669645	6.188397	-0.481248
13	Southern	8.066432	7.471902	-0.594530
14	South Western	8.498394	7.650205	-0.848189

Figure 3 - NHH demand tariff changes



The weighted average NHH tariff is 0.57p/kWh lower than in the November forecast. This decrease is attributable to the:

- Reduced amount of zonal revenue to be recovered from the NHH charging base following the decrease in overall revenue to be recovered.
  - This is offset by the increase in the EET credit.
- Increase in the NHH forecast charging base to 25.5 TWh, this aligns with the expected demand shift under BSC mod P339.

The impact of these changes decrease tariffs across all zones, larger reductions are mostly seen in zones 8 (Midlands) and 14 (South Western) which decreases their tariffs by 0.67p/kWh and 0.84p/kWh respectively.

Generally, the variations year on year across the zones are attributable to changes in our demand forecast modelling approach which now more accurately captures variations in embedded renewable generation across GB and NHH/HH demand shifts. This has been further enhanced by using historical metered demand and embedded export data from Elexon through BSC modifications P348/349 as part of CMP264/265.

Generation tariffs

This section summarises the April generation tariffs for 2019/20, how these tariffs were calculated and how they have changed from the November forecast.

Table 6 – Summary of generation tariffs

Generation Tariffs	2019/20 Initial	2019/20 April	Change since last forecast
Residual	-3.846092	-3.291240	0.554852
Average Generation Tariff	6.007289	6.020832	0.013543

N.B. These generation average tariffs include local tariffs

Average generation tariffs have increased slightly by £0.01/kW, due to increased revenue to be recovered from generation. The increase in residual (by £0.55/kW), is due to a decrease in revenue expected to be recovered from offshore local circuits.

Generation wider tariffs

The following section provides a summary of how the wider generation tariffs have changed between the November forecast and this April forecast. The comparison uses example tariffs for Conventional Carbon generators with an ALF of 80%, Conventional Low Carbon generators with an ALF of 80%, and Intermittent generators with an ALF of 40%.

Under the current methodology each generator has its own load factor as listed in Appendix D. These have been updated for the calculation of 2019/20 tariffs.

The classifications for different technology types are below:

Conventional Carbon	Conventional Low Carbon	Intermittent
Biomass CCGT/CHP Coal OCGT/Oil Pumped storage	Nuclear Hydro	Offshore wind Onshore wind Tidal

Table 7 - Generation wider tariffs

						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	2.644727	17.784775	16.345645	-3.291240	26.657823	29.926952	20.168315
2	East Aberdeenshire	4.867379	10.302484	16.345645	-3.291240	22.894642	26.163771	17.175399
3	Western Highlands	2.077981	17.936305	16.355925	-3.291240	26.220525	29.491710	20.239207
4	Skye and Lochalsh	-4.039890	17.936305	16.240455	-3.291240	20.010278	23.258369	20.123737
5	Eastern Grampian and Tayside	3.058380	15.461012	15.747873	-3.291240	24.734248	27.883823	18.641038
6	Central Grampian	3.777984	14.711406	15.423790	-3.291240	24.594901	27.679659	18.017112
7	Argyll	3.166931	11.710463	27.236802	-3.291240	31.033503	36.480863	28.629747
8	The Trossachs	3.579469	11.710463	14.061990	-3.291240	20.906191	23.718589	15.454935
9	Stirlingshire and Fife	2.385707	8.911269	13.187811	-3.291240	16.773731	19.411293	13.461079
10	South West Scotlands	2.429307	9.452900	13.331080	-3.291240	17.365251	20.031467	13.821000
11	Lothian and Borders	3.671094	9.452900	7.498705	-3.291240	13.941138	15.440879	7.988625
12	Solway and Cheviot	1.967298	5.395649	7.552484	-3.291240	9.034564	10.545061	6.419504
13	North East England	3.888934	3.009497	3.947429	-3.291240	6.163235	6.952721	1.859988
14	North Lancashire and The Lakes	1.593156	3.009497	2.666575	-3.291240	2.842774	3.376089	0.579134
15	South Lancashire, Yorkshire and Humber	4.480390	0.788798	0.117713	-3.291240	1.914359	1.937901	-2.858008
16	North Midlands and North Wales	3.946194	-0.821362		-3.291240	-0.002136	-0.002136	-3.619785
17	South Lincolnshire and North Norfolk	2.124119	-0.466464		-3.291240	-1.540292	-1.540292	-3.477826
18	Mid Wales and The Midlands	1.216122	-0.240749		-3.291240	-2.267717	-2.267717	-3.387540
19	Anglesey and Snowdon	4.442770	-0.635745		-3.291240	0.642934	0.642934	-3.545538
20	Pembrokeshire	9.183173	-4.517385		-3.291240	2.278025	2.278025	-5.098194
21	South Wales & Gloucester	6.180217	-4.492046		-3.291240	-0.704660	-0.704660	-5.088058
22	Cotswold	3.033858	2.270828	-6.740769	-3.291240	-3.833335	-5.181489	-9.123678
23	Central London	-5.759783	2.270828	-6.615453	-3.291240	-12.526723	-13.849814	-8.998362
24	Essex and Kent	-4.082301	2.270828		-3.291240	-5.556879	-5.556879	-2.382909
25	Oxfordshire, Surrey and Sussex	-1.521341	-2.983857		-3.291240	-7.199667	-7.199667	-4.484783
26	Somerset and Wessex	-1.407710	-4.220289		-3.291240	-8.075181	-8.075181	-4.979356
27	West Devon and Cornwall	0.052621	-5.724538		-3.291240	-7.818249	-7.818249	-5.581055

The 80% and 40% load factors used in this table are for illustration only.

Changes since the last generation tariffs forecast

The following section provides details of the wider and local generation tariffs for 2019/20 and how these have changed compared with the November forecast.

Generation wider zonal tariffs

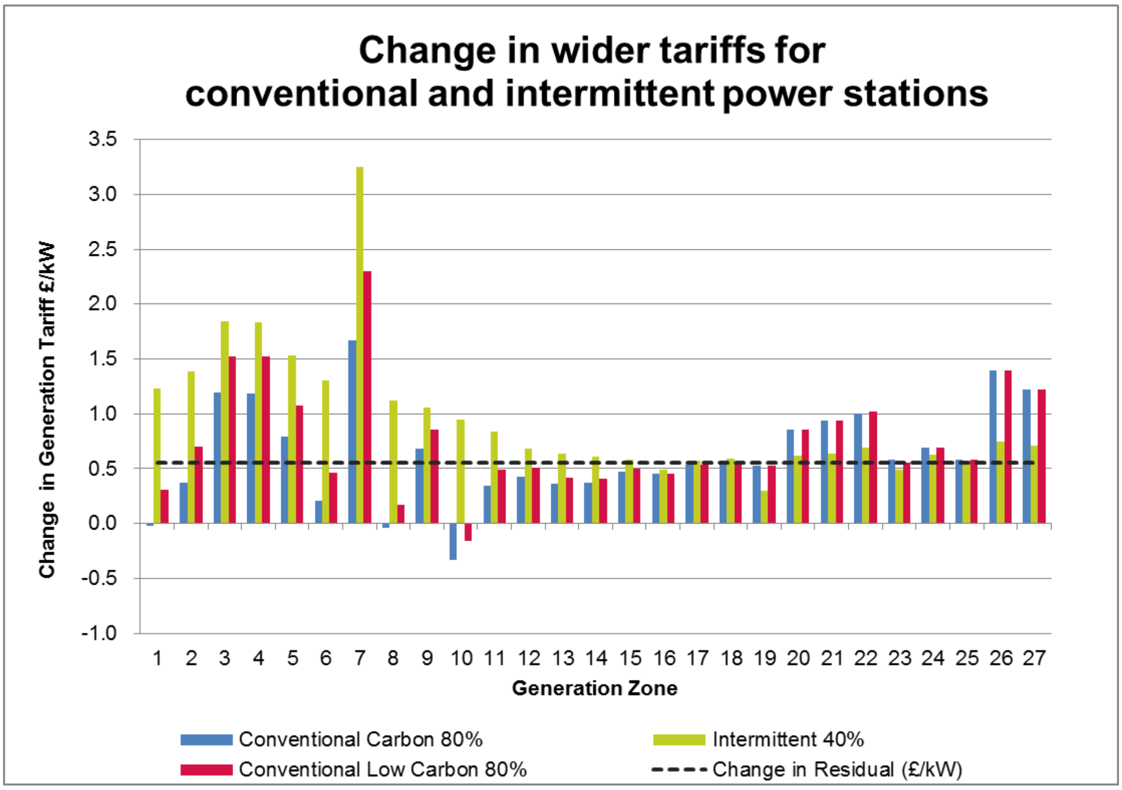
Table 8 and Figure 4 show the changes in generation wider TNUoS tariffs between November and this April 2019/20 forecast.

Table 8 – Generation tariff changes

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

Wider Generation Tariffs (£/kW)											
		Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			Change in Residual (£/kW)
Zone	Zone Name	2019/20 Initial (£/kW)	2019/20 April (£/kW)	Change (£/kW)	2019/20 Initial (£/kW)	2019/20 April (£/kW)	Change (£/kW)	2019/20 Initial (£/kW)	2019/20 April (£/kW)	Change (£/kW)	
1	North Scotland	26.681972	26.657823	-0.024149	29.617483	29.926952	0.309469	18.940031	20.168315	1.228284	0.554852
2	East Aberdeenshire	22.524095	22.894642	0.370547	25.459606	26.163771	0.704165	15.786756	17.175399	1.388642	0.554852
3	Western Highlands	25.029989	26.220525	1.190536	27.965500	29.491710	1.526210	18.392731	20.239207	1.846476	0.554852
4	Skye and Lochalsh	18.825619	20.010278	1.184659	21.739835	23.258369	1.518534	18.286257	20.123737	1.837480	0.554852
5	Eastern Grampian and Tayside	23.944419	24.734248	0.789829	26.809050	27.883823	1.074773	17.104774	18.641038	1.536264	0.554852
6	Central Grampian	24.385134	24.594901	0.209767	27.213747	27.679659	0.465912	16.711905	18.017112	1.305208	0.554852
7	Argyll	29.367036	31.033503	1.666467	34.179406	36.480863	2.301457	25.377651	28.629747	3.252096	0.554852
8	The Trossachs	20.941515	20.906191	-0.035324	23.544588	23.718589	0.174001	14.331165	15.454935	1.123770	0.554852
9	Stirlingshire and Fife	16.090458	16.773731	0.683273	18.553843	19.411293	0.857450	12.401838	13.461079	1.059240	0.554852
10	South West Scotlands	17.699996	17.365251	-0.334745	20.193258	20.031467	-0.161791	12.875596	13.821000	0.945404	0.554852
11	Lothian and Borders	13.599829	13.941138	0.341309	14.947409	15.440879	0.493470	7.147185	7.988625	0.841440	0.554852
12	Solway and Cheviot	8.604124	9.034564	0.430440	10.031674	10.545061	0.513387	5.736111	6.419504	0.683393	0.554852
13	North East England	5.796281	6.163235	0.366954	6.536735	6.952721	0.415986	1.221911	1.859988	0.638077	0.554852
14	North Lancashire and The Lakes	2.474556	2.842774	0.368217	2.965459	3.376089	0.410630	-0.025845	0.579134	0.604979	0.554852
15	South Lancashire, Yorkshire and Humber	1.437678	1.914359	0.476681	1.437678	1.937901	0.500223	-3.440318	-2.858008	0.582310	0.554852
16	North Midlands and North Wales	-0.452034	-0.002136	0.449899	-0.452034	-0.002136	0.449899	-4.107778	-3.619785	0.487993	0.554852
17	South Lincolnshire and North Norfolk	-2.077415	-1.540292	0.537123	-2.077415	-1.540292	0.537123	-4.050870	-3.477826	0.573044	0.554852
18	Mid Wales and The Midlands	-2.834791	-2.267717	0.567074	-2.834791	-2.267717	0.567074	-3.980882	-3.387540	0.593343	0.554852
19	Anglesey and Snowdon	0.111310	0.642934	0.531624	0.111310	0.642934	0.531624	-3.846320	-3.545538	0.300782	0.554852
20	Pembrokeshire	1.423122	2.278025	0.854903	1.423122	2.278025	0.854903	-5.719320	-5.098194	0.621126	0.554852
21	South Wales & Gloucester	-1.644852	-0.704660	0.940192	-1.644852	-0.704660	0.940192	-5.728801	-5.088058	0.640742	0.554852
22	Cotswold	-4.839720	-3.833335	1.006385	-6.200326	-5.181489	1.018837	-9.817744	-9.123678	0.694067	0.554852
23	Central London	-13.106235	-12.526723	0.579512	-14.400844	-13.849814	0.551030	-9.487760	-8.998362	0.489399	0.554852
24	Essex and Kent	-6.244625	-5.556879	0.687746	-6.244625	-5.556879	0.687746	-3.014716	-2.382909	0.631808	0.554852
25	Oxfordshire, Surrey and Sussex	-7.778885	-7.199667	0.579218	-7.778885	-7.199667	0.579218	-5.053958	-4.484783	0.569176	0.554852
26	Somerset and Wessex	-9.473625	-8.075181	1.398444	-9.473625	-8.075181	1.398444	-5.723304	-4.979356	0.743948	0.554852
27	West Devon and Cornwall	-9.038110	-7.818249	1.219861	-9.038110	-7.818249	1.219861	-6.289124	-5.581055	0.708069	0.554852

Figure 4 - Variation in generation zonal tariffs



There is a general trend of tariff increase by around £0.5/kW, because of the less negative residual element compared to the November forecast.

The dominant tariffs in zones 1-9 are Year Round tariffs, which are then split into Year Round Not Shared and Year Round Shared, according to the aggregated fuel mix behind each zonal boundary. Due to the increased proportion of renewables connecting in north Scotland, the Year Round Not Shared tariffs have increased in downstream zones. In zones 1-9, this has driven up the tariffs for intermittent generation by around £1-2/kW, with smaller scale changes in Conventional tariffs. The increase is more pronounced in zone 7, due to the relatively long “spur” of MITS circuits in this area.

The increase in TEC in south coast (zone 24) has reduced the North-South system flow, and has led to less negative tariffs in negative zones, particularly in zone 26 and 27.

Onshore local tariffs for generation

Onshore local substation tariffs

Local substation tariffs reflect the cost of the first transmission substation to which transmission connected generators connect. They are increased each year by Average May – October RPI, and have been updated from the November forecast to reflect revised RPI forecast for the period May 2018 to October 2018.

Table 9 - Local substation tariffs

2019/20 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.197988	0.113261	0.081607
<1320 MW	Redundancy	0.436150	0.269848	0.196255
>=1320 MW	No redundancy	0	0.355124	0.256827
>=1320 MW	Redundancy	0	0.583024	0.425559

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 flows and RPI. If you require further information around a particular local circuit tariff please feel free to contact us.

Some generator users have their local circuits tariffs revised through an additional one off charge. These are listed in Table 11.

Table 10 - Onshore local circuit tariffs

We have updated local circuit modelling for two sites, following updated information regarding the configuration at these sites. This has resulted in local circuit tariff changes at Blackhill and Glenglass.

A flip of local generation/demand balance around Nant has led to significant change to its local circuit tariff .

All other local circuit tariffs remain relatively stable.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.233361	Dunlaw Extension	1.479979	Lochay	0.360863	Millennium South	0.928601
Aigas	0.644948	Dunhill	1.412438	Luichart	0.565540	Aberdeen Bay	2.571147
An Suidhe	-0.941215	Dunmaglass	1.830822	Mark Hill	0.863413	Killingholme	0.700825
Arecleoch	2.048112	Edinbane	6.748862	Marchwood	0.376358	Middleton	0.109808
Baglan Bay	0.750203	Ewe Hill	1.355115	Millennium Wind	1.800997		
Beinneun Wind Farm	1.481122	Fallago	0.199489	Moffat	0.169514		
Bhlaraidh Wind Farm	0.648898	Farr	3.515921	Mossford	0.441973		
Black Hill	1.531435	Fernoch	4.337616	Nant	2.474770		
BlackCraig Wind Farm	6.207678	Ffestiniogg	0.249487	Necton	-0.362207		
Black Law	1.723120	Finlarig	0.315755	Rhigos	0.100382		
BlackLaw Extension	3.654099	Foyers	0.742535	Rocksavage	0.017458		
Carrington	-0.032852	Galawhistle	1.458487	Saltend	0.336249		
Clyde (North)	0.108145	Glendoe	1.813886	South Humber Bank	0.934341		
Clyde (South)	0.125064	Glenglass	2.938700	Spalding	0.277674		
Corriegarth	3.108877	Gordonbush	0.196764	Strathbrora	0.069805		
Corriemoillie	1.640653	Griffin Wind	9.567902	Stronelairg	1.417687		
Coryton	0.051519	Hadyard Hill	2.729474	Strathy Wind	2.029059		
Cruachan	1.865597	Harestanes	2.474525	Wester Dod	0.368974		
Crystal Rig	0.033422	Hartlepool	0.592087	Whitelee	0.104656		
Culligran	1.709128	Hedon	0.178440	Whitelee Extension	0.290944		
Deanie	2.807854	Invergarry	1.399172	Gills Bay	2.483408		
Dersalloch	2.375375	Kilgallioch	1.037840	Kype Muir	1.462664		
Didcot	0.515325	Kilmorack	0.194752	Middle Muir	1.954673		
Dinorwig	2.365979	Langage	0.648640	Dorenell	2.069507		

Table 11 - CMP203: Circuits subject to one-off charges

As part of their connection offer, generators can agree to undertake one-off payments for certain infrastructure cable assets, which affect the way that they are modelled in the Transport and Tariff model. This table shows the lines 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 2.14.4, 14.4, and 14.15.15 onwards.

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

Offshore local tariffs for generation

Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) 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 by average May to October RPI each year. Offshore local generation tariffs associated with projects due to transfer in 2019/20 will be confirmed once asset transfer has taken place.

Table 12 - Offshore Local Tariffs 2019/20

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.974913	41.724736	1.036082
Greater Gabbard	14.952024	34.358279	0.000000
Gunfleet	17.259436	15.845514	2.961618
Gwynt Y Mor	18.209172	17.938284	0.000000
Lincs	14.903790	58.351746	0.000000
London Array	10.145401	34.554672	0.000000
Ormonde	24.654148	45.928368	0.366010
Robin Rigg East	-0.456068	30.210634	9.363666
Robin Rigg West	-0.456068	30.210634	9.363666
Sheringham Shoal	23.820180	27.935491	0.607235
Thanet	18.139932	33.801178	0.813714
Walney 1	21.277698	42.374481	0.000000
Walney 2	21.122951	42.747802	0.000000
West of Duddon Sands	8.210483	40.513644	0.000000
Westermost Rough	17.288517	29.244773	0.000000
Humber Gateway	14.490338	32.695033	0.000000

Background to TNUoS charging

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

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

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

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

revenue allowances.

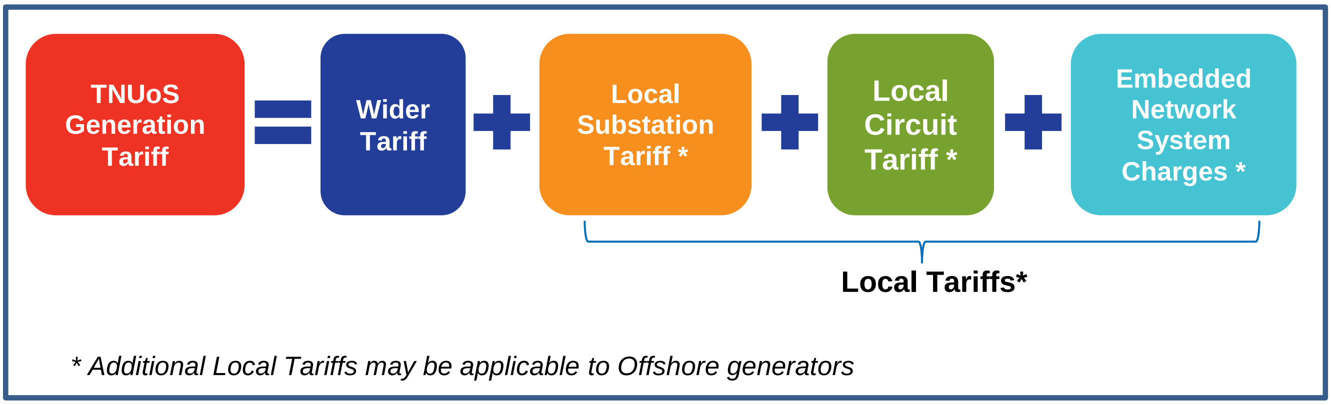
Generation charging principles

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

The TNUoS tariff specific to each generator depends on many factors, including the location, type of connection, connection voltage, plant type and volume of TEC (Transmission Entry Capacity) held by the generator. The TEC figure is equal to the maximum volume of MW the generator is allowed to output 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 generators that are not directly connected to the transmission network and are not applicable to all generators.

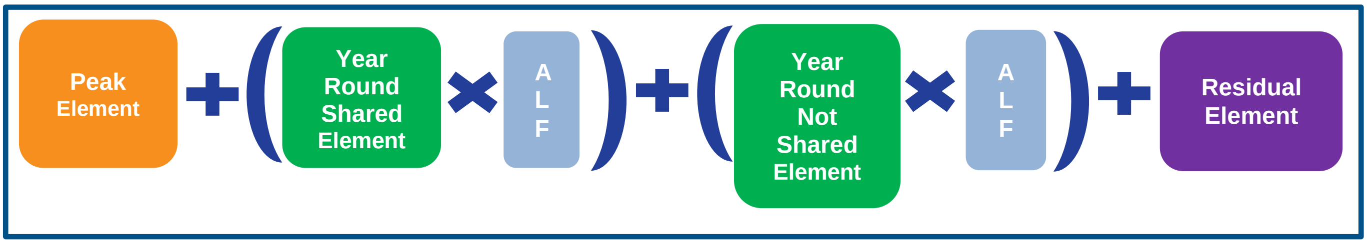
The Wider tariff

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.

As CUSC Modification CMP268 has added an extra variation to the calculation formula, generators classed as Conventional Carbon now pay the Year Round Not Shared element in proportion to their ALF.

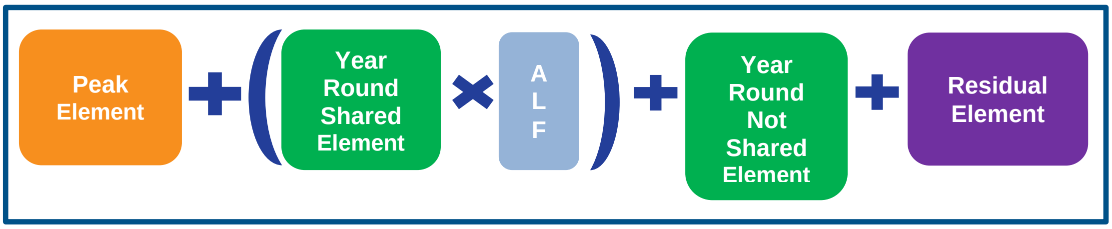
Conventional Carbon Generators

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



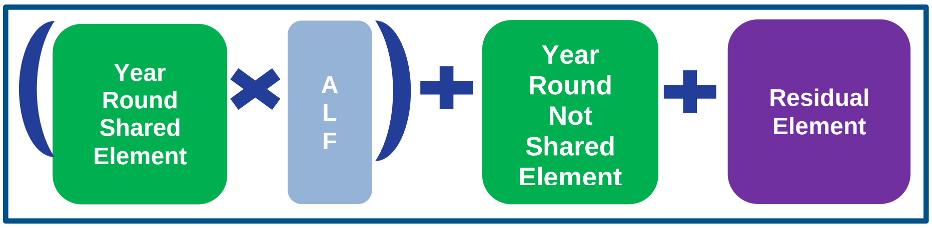
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

The Annual Load Factors used in the April tariffs are listed in Appendix D.

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 are 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[‡‡] if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS charges to be paid directly to the DNO (Distribution Network Owner) in that region, which do not form part of TNUoS.

Embedded-connected offshore generators will need to pay an estimated DUoS charge to NGET through TNUoS tariffs to cover DNO charges, called ETUoS (Embedded Transportation Use of System).

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 OFTO.[§§]

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 liability is as follows:

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

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

TNUoS charges are billed each month, for the month ahead.

Generators with negative TNUoS tariffs

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

[‡‡] *For more information about connections, please visit our website:* *https://www.nationalgrid.com/uk/electricity/connections/applying-connection*

[§§] *These specific charges include any onshore local circuit and substation charges.*

The value used for this reconciliation is the average output of the 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 14.18.13–17.

Demand charging principles

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

HH gross demand tariffs

HH gross demand tariffs are charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year. 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 is available, via the NGET website.[***] The tariff is charged on a £/kW basis. On triads, HH customers are charged the HH gross demand tariff against their gross demand volumes.

HH metered customers tend to be large industrial users, however as the rollout of smart meters progresses, more domestic demand will become HH metered as we have forecasted in the 2019/20 charging base under P339

Embedded export tariffs

The EET is a new tariff under CMP 264/265 and is paid to customers based on the HH metered export volume during the triads (the same triad periods as explained in detail above). This tariff is payable to exporting HH demand customers and embedded generators (<100MW CVA registered).

This tariff contains the locational demand elements, a phased residual over 3 years (reaching £0/kW in 2020/21) and an Avoided GSP Infrastructure Credit. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through demand tariffs.

Customers must now submit forecasts for both HH gross demand and embedded export volumes as to what their expected demand volumes will be. 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 suppliers any embedded export payment will be fed into a net demand charge (gross demand – payment for embedded export) which will be capped at the level of the total demand charge so not to exceed the demand charge. Embedded generators

[***] *http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Triad-Data/*

(<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads.

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

NHH demand tariffs

NHH metered customers are charged based on their demand usage between 16:00 – 19:00 on every day of the year. Suppliers must submit forecasts throughout the year as to what their expected demand volumes will be in each demand zone. The tariff is charged on a p/kWh basis. The NHH methodology remains the same under CMP264/265.

Suppliers 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.

Updates to revenue & the charging model since the last forecast

Since the November forecast tariffs were published, we have updated allowed revenue for some Transmission Owners, the local circuits model, the generation background and demand charging bases and RPI.

There have been no changes to the transport model circuits, or the error margin that is used to calculate the proportion of revenue to be recovered from generation and demand (G/D split).

Changes affecting the locational element of tariffs

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

- Contracted generation as of March 2018;
- Local circuits; and
- RPI (which increases the expansion constant).

Table 13 – Contracted and modelled TEC

Contracted TEC is the volume of TEC with connection agreements for the 2019/20 period, which can be found on the TEC register.[†††] Modelled TEC is the amount of TEC we have entered into the Transport model to calculate system flows, which includes interconnector TEC.

[†††] *See the Registers, Reports and Updates section at* https://www.nationalgrid.com/uk/electricity/connections/after-you-have-connected

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2019/20 and liable to pay generation TNUoS charges. Chargeable TEC volumes are always based on National Grid's best view of the likely volume of generation TEC connected to the system in the relevant charging year.

The contracted TEC volumes used in this April 2018 forecast was based on the TEC register from late March 2018. We will forecast our best view of modelled TEC until 31 October, after which we must use the TEC as published in the TEC register as of 31 October, in accordance with CUSC 14.15.6.

(GW)	2018/19	2019/20 November Forecast	2019/20 April Forecast
Contracted TEC	79.0	85.5	85.9
Modelled Best View TEC	79.0	77.7	77.5
Chargeable TEC	71.9	73.8	71.7

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.

Table 14 – Interconnectors

The table below reflects the contracted position of interconnectors in the interconnector register as of March 2018

Interconnector	Site	Interconnected System	Generation Zone	Transport Model (Generation MW) Peak	Transport Model (Generation MW) Year Round	Charging Base (Generation MW)
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	1000	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	80	0

RPI

The RPI index for the components detailed below is calculated based on the average May – October RPI for 2019/20.

Expansion Constant

The expansion constant has increased from 14.08310011 in 2018/19 to a forecast of 14.55396624 in the April tariffs. This reflects our latest view of the RPI.

Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by May - October RPI as are offshore local circuit tariffs, so have been updated from the November forecast to reflect actual RPI for the period May 2018 – October 2018.

Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the November forecast, tariffs have now been calculated to recover £2,835.8m of revenue. This is a decrease of £132.5m from the November forecast of £2968.4m, mainly due to revised forecast of OFTO revenue and some other pass-through items. Delays to expected asset transfer dates for OFTO projects have affected the number of OFTOs on whose behalf we expect to collect revenues in 2019/20 and also the proportion of the year over which new OFTO's revenues will be pro-rated.

There has been a drop of around £50m in the forecast of pass-through elements of NGET revenue, including adjustment to business rate, licence fee and termination etc. These pass-through elements will be advised by individual TOs as part of their RRP activity, and will be updated in November draft tariffs.

Table 15 – Allowed revenues

£m Nominal	2018/19	November C5 for 2019/20	April Forecast 2019/20
National Grid			
Price controlled revenue	*1,653.9*	*1,768.5*	*1,728.1*
Less income from connections	*44.0*	*41.9*	*44.0*
Income from TNUoS	**1,609.9**	**1,726.6**	**1,684.1**
Scottish Power Transmission			
Price controlled revenue	*364.8*	*404.5*	*404.5*
Less income from connections	*14.9*	*14.5*	*14.5*
Income from TNUoS	**350.0**	**390.0**	**390.0**
SHE Transmission			
Price controlled revenue	*369.8*	*352.9*	*352.9*
Less income from connections	*3.4*	*3.5*	*3.5*
Income from TNUoS	**366.4**	**349.4**	**349.4**
Interconnector cap and floor revenue Adj Term	(6.8)	(6.8)	(6.8)
Offshore	**318.1**	**466.7**	**386.5**
Network Innovation Competition	**32.7**	**42.5**	**32.7**
Total to Collect from TNUoS	**2,670.3**	**2,968.4**	**2,835.8**

Generation / Demand (G/D) Split

The G/D split has changed slightly since the November tariff forecast, where the proportion of generation has increased by 0.3% and subsequently demand has decreased by 0.3%.

Section 14.14.5 (v) in the Connection and Use of System Code (CUSC) currently limits average annual generation use of system charges in Great Britain to €2.5/MWh. The net revenue that can be recovered from generation is therefore determined by: the €2.5/MWh limit, exchange rate and forecast output of chargeable generation. An error margin is also applied to reflect revenue and output forecasting accuracy.

Exchange Rate

As prescribed by the Use of System charging methodology, the exchange rate for 2019/20 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2018. The value published is €1.13/£, which has decreased since the November tariffs.

Generation Output

The forecast output of generation remains the same as the November initial forecast. This figure will be updated in June, when we receive inputs from the latest Future Energy Scenario.

Error Margin

The error margin remains unchanged from the November forecast at 21%. The parameters used to calculate the proportions of revenue collected from generation and demand are shown below.

Table 16 – Generation and demand revenue proportions

		2019/20 April
CAPEC	Limit on generation tariff (€/MWh)	2.50
y	Error Margin	21.0%
ER	Exchange Rate (€/£)	1.13
MAR	Total Revenue (£m)	2,835.8
GO	Generation Output (TWh)	247.0
G	% of revenue from generation	15.2%
D	% of revenue from demand	84.8%
G.MAR	Revenue recovered from generation (£m)	431.8
D.MAR	Revenue recovered from demand (£m)	2404.0

Charging bases for 2019/20

Generation

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

We are unable to breakdown our best view of generation as some of the information used to derive it could be commercially sensitive. The change in contracted TEC, as per the TEC register is shown in the appendices.

Demand

Our forecasts of demand and embedded generation have been updated since the November tariff forecast using a Monte Carlo modelling approach. This incorporates our latest data including:

- Historical gross metered demand and embedded export volumes (August 2014-March 2018)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

Following our review of the metered demand and export data, we have seen a relatively high level of embedded export volumes over triads in 2017/18 compared to previous years. We also recognise there will be an expected demand shift between NHH to HH under BSC mod P339. These changes in our outturn charging base have been factored into our projections for 2019/20 and future years. This has resulted in:

- An increase in the embedded export volume which is forecasted to reach 7.75GW in 2019/20.
- An increase in NHH to 25.5 TWh
- A reduction in gross HH demand to 18GW.

Overall we assume that recent historical trends in steadily declining volumes will continue due to several factors including the growth in distributed generation and “behind the meter” microgeneration.

Table 17 – Charging base

Charging Bases	2019/20 Initial	2019/20 April
Generation (GW)	73.8	71.7
NHH Demand (4pm-7pm TWh)	23.5	25.5
Net Charging		
Total Average Net Triad (GW)	45.1	43.6
HH Demand Average Net Triad (GW)	12.9	10.3
Gross charging		
Total Average Gross Triad (GW)	51.2	51.3
HH Demand Average Gross Triad (GW)	19.0	18.0
Embedded Generation Export (GW)	6.1	7.8

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 2018/19 ALFs, based upon data from 2012/13 - 2016/17 available from the National Grid website.[§§§] The ALFs for 2019/20 will be calculated later in this year.

Generation and Demand Residuals

The residual element of tariffs can be calculated using the formulas below. This can be used to assess the effect of changing the assumptions in our tariff forecasts without the need to run the transport and tariff model.

Generation Residual = (Total Money collected from generators as determined by G/D split less money recovered through location tariffs, onshore local substation & circuit tariffs and offshore local circuit & substation tariffs) divided by the total chargeable TEC

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

Where

- R_G is the generation residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from generation
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from generation locational zonal tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_C is the TNUoS revenue recovered from onshore local circuit tariffs (£m)
- L_S is the TNUoS revenue recovered from onshore local substation tariffs (£m)
- B_G is the generator charging base (GW)

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

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

[§§§] https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf

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 (Half-Hour equivalent GW)

Z_G, Z_D, L_C, and EE are determined by the locational elements of tariffs, and for EE the value of the AGIC and phased residual.

Table 18 - Residual calculation

	Component	2019/20 Initial	2019/20 April
G	Proportion of revenue recovered from generation (%)	14.9%	15.2%
D	Proportion of revenue recovered from demand (%)	85.1%	84.8%
R	Total TNUoS revenue (£m)	2,968	2,836
Generation Residual			
R_G	Generator residual tariff (£/kW)	-3.85	-3.29
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	331.4	330.7
O	Revenue recovered from offshore local tariffs (£m)	356.0	298.7
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.1	19.2
S_G	Revenue recovered from onshore local circuit tariffs (£m)	20.0	19.1
B_G	Generator charging base (GW)	73.8	71.7
Gross Demand Residual			
R_D	Demand residual tariff (£/kW)	52.13	50.30
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-65.3	-66.7
EE	Amount to be paid to Embedded Exports (£m)	81.6	110.9
B_D	Demand gross charging base	51.2	51.3

Small generator discount

There will be no small generator discount from 1 April 2019. Therefore applicable generators will no longer receive the discount to their TNUoS tariffs. Similarly, there will be no additional charge added to demand traiffs to recover the costs of the scheme.

The small generator discount was payable to customers in accordance with National Grid's System Operator licence C13. Section 5 of C13 states that the discount will end on 31 March 2019.

Tools and Supporting Information

Further information

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

Charging forums

We will hold a webinar for the April tariffs on Friday 11 May 2018 from 13:30 to 14:30. If you wish to join the webinar, please use this registration link (**Register)**

We always welcome questions and are happy to discuss specific aspects of the material contained in the April tariffs report should you wish to do so.

Charging models

We can provide a copy of our charging model. 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 the 2019/20 forecasts:

https://www.nationalgrid.com/tnuos

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Appendices

Appendix A: Possible changes to the charging methodology affecting 2019/20 TNUoS Tariffs

Appendix B: Locational demand tariff charges

Appendix C: Locational demand profiles

Appendix D: Annual Load Factors

Appendix E: Contracted generation changes since the June forecast

Appendix F: Transmission company revenues

Appendix G: Generation zones map

Appendix H: Demand zones map

Appendix A: Changes and possible changes to the charging methodology affecting 2019/20 TNUoS Tariffs

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2019/20 onwards. 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.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code?mods

Judicial Review of CMP264/265
From 2018/19 the demand charging methodology changed to charge on of Gross HH demand, and credit for embedded export. This replaced the previous net charging methodology.

This decision remains subject to judicial review in 'late April' 2018.

If Ofgem's decision to approve the modification is quashed, then we may need to set tariffs for 2019/20 on the previous net methodology. This may also affect 2018/19 tariffs through a 'mid year tariff change'[****]

Other Modifications
A summary of the mods already in process which could affect the 2019/20 tariffs and their status are listed below. More detail follows this table.

Other modifications may be raised throughout the year which may impact tariffs for 2019/20.

Table 20: Summary of CUSC modifications affecting 2019/20 TNUoS Tariffs

Mod Number	Description	Status	Status in the April Forecast
Modification which may affect tariffs from 1 April 2019 if approved			
251	Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010	Pending Ofgem decision – the final modification report was submitted to Ofgem in October 2016.	Not implemented, as not decision yet published by Ofgem
Modifications being considered by CUSC Workgroups which may affect tariffs from 1 April 2019			

[****] *https://www.nationalgrid.com/sites/default/files/documents/Information%20on%20a%20Potential%20Mid-Year%20Charge%20Change%20-%202018-19.pdf*

280	Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users	At workgroup	Not implemented, as no decision yet published by Ofgem
Modifications being considered by CUSC Workgroups which may affect the tariff setting process, have a consequential impact on how/when tariffs are known			
286	Improving TNUoS Predictability through Increased Notice of the Target Revenue used in the TNUoS Tariff Setting Process	At workgroup	N/A
287	Improving TNUoS Predictability Through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process	At workgroup	N/A
292	Introducing a Section 8 cut-off date for changes to the Charging Methodologies	At workgroup	N/A

Appendix B: Locational demand tariff charges

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 November forecast to the April forecast.

The zonal variations for both the peak security and year round tariffs have been driven by the changes in generation TEC. This can be seen largely in zones 10 (South Wales) and 14 (South Western) which has contributed to the larger reductions in half-hourly and embedded export tariffs for these regions.

Table 21 – Locational tariffs

	2019/20 Initial		2019/20 April		Changes	
Zone	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-1.982874	-28.463727	-2.047907	-28.513683	-0.065033	-0.049956
2	-2.201787	-20.763507	-2.240275	-20.639597	-0.038489	0.123911
3	-3.642435	-6.990777	-3.581823	-6.824064	0.060612	0.166713
4	-1.328706	-2.406292	-1.126515	-2.449699	0.202191	-0.043407
5	-3.153040	-0.507585	-2.842328	-0.442222	0.310712	0.065363
6	-1.863272	-0.303844	-2.289935	0.290020	-0.426663	0.593864
7	-2.216382	2.340628	-2.161976	2.315725	0.054406	-0.024904
8	-1.468306	2.829388	-1.437143	2.890914	0.031163	0.061526
9	1.319040	0.880796	1.354743	0.837746	0.035703	-0.043050
10	-5.942829	4.698673	-6.139131	4.501087	-0.196303	-0.197585
11	4.196723	0.774353	4.203998	0.722699	0.007275	-0.051653
12	5.630045	2.446419	5.650585	2.398599	0.020540	-0.047820
13	1.943261	4.476748	1.838026	4.331643	-0.105235	-0.145105
14	-0.601753	5.767531	-0.921749	5.429782	-0.319996	-0.337749

Appendix C: Locational demand profiles

The table below shows the latest demand forecast used in the April tariff forecast.

The locational model demand profiles have been updated following the submission of week 24 data from the DNOs and directly connected demand (DCC).

Locational model demand remains the same as the November forecast at 51.9GW. Overall net peak demand has now changed to 43.5GW due to an increase in the forecast level of embedded export in 2019/20.

HH demand is now calculated on a gross basis rather than net, which removes the negative demand caused by embedded generation.

Table 22 – Demand profiles

Zone	Zone Name	2019/20 Initial					2019/20 April				
		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	499	1,457	435	0.73	899	499	1,483	428	0.78	958
2	Southern Scotland	2,695	3,425	1,195	1.62	580	2,695	3,444	1,126	1.77	678
3	Northern	2,702	2,606	1,026	1.16	512	2,702	2,576	902	1.32	439
4	North West	3,067	4,027	1,464	1.88	330	3,067	4,037	1,413	2.02	410
5	Yorkshire	4,384	3,820	1,541	1.71	605	4,384	3,818	1,495	1.83	808
6	N Wales & Mersey	2,558	2,623	1,048	1.19	504	2,558	2,628	991	1.30	550
7	East Midlands	5,376	4,638	1,784	2.10	470	5,376	4,651	1,717	2.24	639
8	Midlands	4,425	4,251	1,542	1.93	198	4,425	4,251	1,389	2.17	335
9	Eastern	6,238	6,413	2,021	2.99	660	6,238	6,447	1,931	3.24	806
10	South Wales	1,674	1,817	820	0.81	322	1,674	1,822	779	0.88	510
11	South East	3,871	3,898	1,140	1.85	302	3,871	3,906	1,060	2.01	411
12	London	5,599	4,227	2,259	1.78	139	5,599	4,187	2,203	1.87	171
13	Southern	6,566	5,459	2,025	2.49	402	6,566	5,476	1,933	2.68	693
14	South Western	2,210	2,584	736	1.25	219	2,210	2,597	641	1.40	345
Total		**51,865**	**51,247**	**19,034**	**23.50**	**6,143**	**51,865**	**51,326**	**18,007**	**25.51**	**7,753**

Appendix D: Annual Load Factors

ALFs

Table 23 lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2019/20. 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.

ALFs have been calculated using Transmission Entry Capacity, Metered Output and Final Physical Notifications from charging years 2012/13 to 2016/17. Generators which commissioned after 1 April 2014 will have fewer than three complete years of data so the Generic ALF listed below are added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2019/20 also use the Generic ALF.

These were finalised for the Five-year forecast tariffs published on 1 December 2017.[§§§]

[§§§] *https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf*

Table 23: Specific Annual Load Factors

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
ABERTHAW	Coal	Actual	Actual	Actual	Actual	Actual	74.0137%	65.5413%	59.0043%	54.2611%	50.8335%	59.6022%
ACHRUACH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.6464%	36.7140%	34.8994%
AN SUIDHE WIND FARM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6380%	41.5843%	36.9422%	35.4900%	34.0938%	35.5087%
ARECLEOCH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.4826%	33.8296%	29.7298%	36.8612%	19.7246%	32.0140%
BAGLAN BAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.5756%	16.4106%	37.9194%	29.1228%	55.2030%	31.5393%
BARKING	CCGT_CHP	Actual	Actual	Partial	Generic	Generic	2.3383%	1.8802%	14.1930%	0.0000%	0.0000%	6.1371%
BARROW OFFSHORE WIND LTD	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	42.8840%	54.1080%	47.0231%	47.1791%	44.2584%	46.1536%
BARRY	CCGT_CHP	Actual	Actual	Actual	Actual	Partial	0.6999%	1.2989%	0.4003%	2.1727%	25.4300%	1.3905%
BEAULY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	25.4532%	35.6683%	37.1167%	35.0094%	30.4872%	33.7216%
BEINNEUN	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	30.9622%	33.2125%
BHLARAIDH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4338%	34.0364%
BLACK LAW	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	22.0683%	31.9648%	26.7881%	26.9035%	23.4623%	25.7180%
BLACKLAW EXTENSION	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.4635%	13.1095%	26.9702%
BRIMSDOWN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	21.8759%	18.7645%	11.1229%	16.4463%	45.0615%	19.0289%
BURBO BANK	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	16.7781%	25.0233%	30.4355%
CARRAIG GHEAL	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	29.8118%	45.2760%	48.9277%	45.6254%	40.4211%	46.6097%
CARRINGTON	CCGT_CHP	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.7318%	58.0115%	46.6520%
CLUNIE SCHEME	Hydro	Actual	Actual	Actual	Actual	Actual	33.4563%	45.3256%	43.2488%	47.9711%	32.8297%	40.6769%
CLYDE (NORTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.5345%	42.6598%	36.8882%	41.4120%	26.8858%	35.6116%
CLYDE (SOUTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6084%	39.8941%	29.4115%	39.9615%	34.8751%	35.4592%
CONNAHS QUAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.5104%	12.8233%	18.3739%	28.2713%	37.4588%	21.7185%
CONON CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	47.5286%	54.2820%	55.5287%	58.9860%	48.6782%	52.8296%
CORRIEGARTH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	22.5644%	30.4133%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.2315%	33.6356%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.6869%	9.7852%	17.5123%	26.4000%	63.0383%	19.8664%
COTTAM	Coal	Actual	Actual	Actual	Actual	Actual	65.0700%	67.3951%	51.4426%	34.4157%	14.9387%	50.3095%
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	13.7361%	16.0249%	31.3132%	28.2382%	67.2482%	25.1921%
COUR	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.3246%	35.6667%
COWES	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.1743%	0.0956%	0.3135%	0.4912%	0.5319%	0.3264%
CRUACHAN	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	8.4281%	9.6969%	9.0516%	8.8673%	7.1914%	8.7823%
CRYSTAL RIG II	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	40.6845%	50.2549%	47.5958%	48.3836%	40.2679%	45.5546%
CRYSTAL RIG III	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	39.9503%	36.2086%
DAMHEAD CREEK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	45.0617%	77.1783%	67.4641%	64.8983%	68.1119%	66.8248%
DEESIDE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.7551%	17.3035%	13.9018%	17.4579%	27.1090%	18.1722%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
DERSALLOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.7728%	34.1494%
DIDCOT B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	49.0134%	18.6624%	25.5345%	41.1389%	50.1358%	38.5623%
DIDCOT GTS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0720%	0.0902%	0.2843%	0.4861%	0.0452%	0.1488%
DINORWIG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	15.0990%	15.0898%	15.0650%	14.6353%	15.9596%	15.0846%
DRAX	Coal	Actual	Actual	Actual	Actual	Actual	82.4774%	80.5151%	82.2149%	76.2030%	62.2705%	79.6443%
DUDGEON	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	42.4791%	47.1631%
DUNGENESS B	Nuclear	Actual	Actual	Actual	Actual	Actual	59.8295%	61.0068%	54.6917%	70.7617%	79.3403%	63.8660%
DUNLAW EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.3771%	34.8226%	30.0797%	29.1203%	26.5549%	30.5257%
DUNMAGLASS	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.9713%	35.8822%
EDINBANE WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	29.3933%	39.4785%	31.2458%	35.5937%	32.5009%	33.1135%
EGGBOROUGH	Coal	Actual	Actual	Actual	Actual	Partial	72.6884%	72.1843%	45.7421%	27.0157%	39.7693%	63.5383%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	14.5869%	28.2628%	25.3585%	28.1507%	16.1775%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.3314%	34.0023%
FALLAGO	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	32.9869%	54.8683%	44.7267%	55.7992%	43.2176%	51.7981%
FARR WINDFARM TOMATIN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.0149%	44.7212%	38.5712%	40.9963%	34.1766%	37.9147%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	22.1176%	35.3695%	57.4834%	53.1573%	30.9768%	39.8345%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.1362%	63.3619%	72.8484%	57.6978%	63.2006%	62.5662%
FFESTINIOGG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	2.9286%	5.4631%	4.3251%	3.4113%	5.6749%	4.3999%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	61.6386%	49.0374%	45.2435%	27.4591%	8.2478%	40.5800%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	40.2952%	59.9142%	59.4092%	65.1349%	49.6402%	56.3212%
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	13.4800%	14.7097%	12.3048%	15.4323%	11.3046%	13.4982%
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.5600%	33.7451%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.9764%	34.5506%
GARRY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	48.5993%	55.9308%	64.3828%	60.2772%	61.0498%	59.0859%
GLANDFORD BRIGG	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.3336%	1.5673%	0.5401%	1.8191%	2.7682%	1.3088%
GLEN APP	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.1373%	31.2709%
GLENDOE	Hydro	Actual	Actual	Actual	Actual	Actual	17.3350%	36.3802%	32.3494%	34.8532%	23.8605%	30.3544%
GLENMORISTON	Hydro	Actual	Actual	Actual	Actual	Actual	36.3045%	44.4594%	48.7487%	50.6921%	34.6709%	43.1709%
GORDONBUSH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	37.8930%	46.5594%	47.7981%	47.7161%	50.4126%	47.3579%
GRAIN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	25.4580%	41.3833%	44.0031%	39.7895%	53.8227%	41.7253%
GRANGEMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	52.8594%	55.9047%	62.6168%	59.8274%	51.4558%	56.1972%
GREAT YARMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.0270%	20.7409%	18.6633%	59.8957%	63.5120%	33.2212%
GREATER GABBARD OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	40.1778%	48.3038%	42.1327%	50.2468%	43.1132%	44.5166%
GRIFFIN WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	17.9885%	31.9566%	31.3152%	31.0284%	25.8228%	29.3888%
GUNFLEET SANDS I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	50.1496%	56.6472%	47.0132%	50.4650%	45.7940%	49.2093%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
GUNFLEET SANDS II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	45.0132%	52.2361%	44.7211%	49.0521%	43.9893%	46.2622%
GWYNT Y MOR	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	18.8535%	8.0036%	61.6185%	63.1276%	44.8323%	56.5262%
HADYARD HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	27.6927%	31.9488%	27.7635%	36.6527%	31.4364%	30.3829%
HARESTANES	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	22.2448%	28.6355%	27.8093%	22.5464%	26.3304%
HARTLEPOOL	Nuclear	Actual	Actual	Actual	Actual	Actual	80.2632%	73.7557%	56.2803%	53.8666%	78.0390%	69.3583%
HEYSHAM	Nuclear	Actual	Actual	Actual	Actual	Actual	83.3828%	73.3628%	68.8252%	72.7344%	79.6169%	75.2380%
HINKLEY POINT B	Nuclear	Actual	Actual	Actual	Actual	Actual	61.7582%	68.8664%	70.1411%	67.6412%	71.2265%	68.8829%
HUMBER GATEWAY OFFSHORE WIND FARM	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	62.9631%	59.7195%	57.3959%
HUNTERSTON	Nuclear	Actual	Actual	Actual	Actual	Actual	73.5984%	84.7953%	79.1368%	82.1786%	83.2939%	81.5365%
IMMINGHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	50.1793%	37.8219%	56.8316%	69.4686%	71.9550%	58.8265%
INDIAN QUEENS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.3423%	0.2321%	0.0876%	0.0723%	0.0847%	0.1348%
KEADBY	CCGT_CHP	Actual	Actual	Generic	Partial	Actual	4.6125%	0.0001%	0.0000%	35.1858%	28.6076%	11.0734%
KILBRAUR	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	45.2306%	51.3777%	54.3550%	50.3807%	46.5342%	49.4309%
KILGALLIOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.2739%	31.3164%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	32.3429%	45.5356%	44.8205%	53.2348%	27.4962%	40.8997%
KILLINGHOLME (NP)	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	10.6552%	7.4217%	11.6191%	0.0000%	0.0000%	9.8987%
KILLINGHOLME (POWERGEN)	Gas_Oil	Generic	Generic	Generic	Generic	Generic	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
KINGS LYNN A	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	0.0003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0001%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.9115%	40.8749%	34.8629%	16.5310%	44.5413%	39.2164%
LINCS WIND FARM	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	20.3244%	46.5987%	43.8178%	49.1306%	44.5192%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.3807%	33.6286%	49.6644%	39.9829%	64.8597%	41.0920%
LOCHLUICHART	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	24.9397%	20.2103%	29.2663%	31.6897%	27.0554%
LONDON ARRAY	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	38.9520%	51.2703%	64.0880%	66.8682%	53.6245%	61.5269%
LYNEMOUTH	Coal	Generic	Generic	Generic	Partial	Generic	0.0000%	0.0000%	0.0000%	68.0196%	0.0000%	58.6875%
MARCHWOOD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	43.3537%	48.6845%	66.4021%	55.0879%	75.4248%	56.7248%
MARK HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	30.1675%	30.2863%	26.7942%	34.0227%	21.9653%	29.0827%
MEDWAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	1.0718%	14.5545%	28.0962%	34.1799%	35.1505%	25.6102%
MILLENNIUM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	42.1318%	52.6618%	53.2636%	48.4038%	44.9764%	48.6806%
NANT	Hydro	Actual	Actual	Actual	Actual	Actual	20.8965%	35.5883%	36.4040%	37.3788%	30.6350%	34.2091%
ORMONDE	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	48.8406%	49.6561%	42.8711%	47.1986%	41.2188%	46.5753%
PEMBROKE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.5434%	60.3928%	67.5346%	64.5596%	77.6478%	64.5459%
PEN Y CYMOEDD	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	26.9446%	31.8733%
PETERBOROUGH	CCGT_CHP	Actual	Actual	Actual	Partial	Actual	0.9506%	1.8311%	1.0929%	4.1032%	1.7914%	1.5718%
PETERHEAD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	31.3766%	41.8811%	0.4858%	23.3813%	42.2292%	32.2130%
RACE BANK	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	45.3062%	48.1055%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	66.7461%	71.7403%	56.1767%	19.6814%	15.4657%	47.5347%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	37.4157%	46.7562%	55.3209%	51.9700%	50.5096%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	38.2254%	48.0629%	53.4150%	56.0881%	51.5383%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.4820%	2.6155%	4.4252%	19.8061%	58.6806%	21.9044%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	10.7188%	7.4695%	5.3701%	7.7906%	15.6538%	8.6596%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	81.5834%	69.0062%	67.9518%	55.6228%	77.4019%	71.4533%
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.2311%	18.2781%	25.6956%	27.2136%	41.6815%	23.7291%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.0549%	25.0221%	18.9719%	28.6790%	19.8588%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.7976%	32.4163%	24.6354%	18.3226%	64.4246%	28.2831%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	36.6431%	49.3517%	46.2286%	53.6184%	46.9715%	47.5173%
SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.0000%	20.7501%	10.2239%	48.9514%	68.9863%	26.6418%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	96.7260%	82.5051%	84.7924%	98.7826%	81.6359%	88.0078%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	9.1252%	14.3471%	15.5941%	13.9439%	8.1782%	12.4721%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.9763%	24.3373%	34.4673%	48.6753%	55.3419%	37.0396%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	34.6976%	33.4800%	39.3092%	47.9407%	60.9748%	40.6492%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	54.4117%	37.6216%	56.6148%	69.4422%	65.7791%	58.9352%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	49.6340%	36.1987%	40.0568%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.1652%	9.4124%	17.2025%	13.1999%	38.0184%	16.8559%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2037%	0.0483%	0.0640%	0.1708%	0.8047%	0.1462%
THANET OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	41.1093%	39.7489%	35.5935%	41.3434%	33.7132%	38.8172%
TODDLEBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.7175%	39.5374%	33.7211%	35.0823%	31.3435%	33.8403%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	84.8669%	86.4669%	91.4945%	85.7725%	97.9942%	87.9113%
USKMOUTH	Coal	Actual	Actual	Partial	Actual	Actual	45.1938%	38.9899%	46.9428%	25.5184%	24.3304%	36.5674%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	44.2799%	57.7046%	52.0555%	50.7535%	47.4617%	50.0902%
WALNEY II	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	54.7907%	61.9219%	58.2355%	35.7988%	54.9727%	58.3767%
WEST BURTON	Coal	Actual	Actual	Actual	Actual	Actual	70.5868%	68.9176%	61.5364%	32.7325%	10.1071%	54.3955%
WEST BURTON B	CCGT_CHP	Partial	Actual	Actual	Actual	Actual	21.3299%	30.3021%	46.8421%	59.3477%	54.2878%	53.4925%
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	40.4447%	40.0506%	48.7540%	48.7691%	45.8579%
WESTERMOST ROUGH	Offshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	26.2900%	54.8014%	58.1061%	46.3992%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.2265%	35.1074%	29.8105%	31.8773%	27.2893%	29.9714%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	12.4146%	27.0102%	27.7787%	26.7655%	23.5253%	25.7670%
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	3.4258%	4.4941%	21.5867%	16.1379%	14.4130%	11.6817%

Table 24: Generic Annual Load Factors

Technology	Generic ALF
Gas_Oil#	0.1890%
Pumped_Storage	10.4412%
Tidal*	18.9000%
Biomass	26.8847%
Wave*	31.0000%
Onshore_Wind	34.3377%
CCGT_CHP	43.2127%
Hydro	41.3656%
Offshore_Wind	49.5051%
Coal	54.0215%
Nuclear	76.4001%

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 Annual Load Factors are calculated in accordance with CUSC 14.15.109. The Biomass ALF for 2016/17 has been copied from the 2015/16 year due to there not being any single majority biomass-fired stations operating over that period.

Appendix E: Contracted generation changes since the November forecast

Table 25 shows the TEC changes notified between November 2017 (used as the basis for the initial forecast) and April 2018 for these April 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's best view and therefore may include different generation to that shown below.

Table 25: Generation Contracted TEC Changes

Power Station	Node	MW Change	Generation Zone
Barry Power Station	ABTH20	93.00	21
Beinn an Tuirc 3	CAAD1Q	50.00	7
Blacklaw Extension	BLKX10	9.00	11
CDCL	COTT40	-50.00	16
Coryton	COSO40	96.00	24
Edinbane Wind, Skye	EDIN10	-1.35	4
Galloper Wind Farm	LEIS10	164.00	18
Keith Hill Wind Farm	DUNE10	4.50	11
Killingholme	KILL40	-600.00	15
Kings Lynn A	WALP40_EME	99.00	17
Peterhead	PEHE20	1180.00	2
Robin Rigg East Offshore Wind Farm	HARK40	-6.00	12
West Burton B	WBUR40	38.00	16
Benbrack Wind Farm	KEON10	-72.00	10
Loganhead Windfarm	EWEH1Q	-36.00	12
MeyGen Tidal	GILB10	-71.00	1
Stella North EFR Submission	STEW40	-25.00	13
Triton Knoll Offshore Wind Farm	BICF4A	-360.00	17
West Burton Energy Storage	WBUR40	-38.00	16

Appendix F: Transmission company revenues

National Grid revenue forecast

We seek to provide the detail behind price control revenue forecasts for National Grid, Scottish Power Transmission and SHE Transmission, however, the contractual position between NGSO and TOs does not presently require a breakdown to the TO final position.

Revenue for offshore networks is included with forecasts by National Grid 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.

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

Network Innovation Competition (NIC) Funding is included in the National Grid price control but is additional to the price controls of onshore and offshore Transmission Owners who receive funding. NIC funding is therefore only shown in the National Grid table.

All reasonable care has been taken in the preparation of these illustrative tables and the data therein. National Grid and other Transmission Owners offer this data without prejudice and cannot be held responsible for any loss that might be attributed to the use of this data. Neither National Grid nor other Transmission Owners 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.

The base revenue forecasts reflect the figures authorised by Ofgem in the RIIO-T1 or offshore price controls.

Table 26 – Indicative National Grid revenue forecast

Description						Notes
Regulatory Year		**Licence Term**	**2018/19 (fixed forecast)**	**2019/20 Initial Forecast**	**2019/20 April Forecast**	
Actual RPI						April to March average
RPI Actual		RPIAt				Office of National Statistics
Assumed Interest Rate		It	0.71%	0.56%	1.16%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1587.6	1585.2	1585.2	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-310.2	-334.0	-334.0	Forecast
RPI True Up	A3	TRUt	-6.1	3.3	3.3	Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.60%	3.50%	3.50%	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.40%	3.00%	3.00%	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.10%	3.00%	3.00%	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.3140	1.3570	1.3570	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1670.5**	**1702.3**	**1702.3**	
Pass-Through Business Rates	B1	RBt	1.6	35.1	0.0	Forecast
Temporary Physical Disconnection	B2	TPDt	0.7	0.0	0.0	Forecast
Licence Fee	B3	LFt	-0.4	4.5	0.0	Forecast
Inter TSO Compensation	B4	ITCt	1.3	0.8	0.0	Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	Forecast
SP Transmission Pass-Through	B6	TSPt	350.0	390.0	390.0	Forecast
SHE Transmission Pass-Through	B7	TSHt	366.4	349.4	349.4	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	318.1	459.9	386.5	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.5	0.6	0.6	Forecast
Interconnectors Cap&Floor Revenue Adjustment	B10	TICFt	-6.8		-6.8	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]	**B**	**PTt**	**1031.5**	**1240.2**	**1119.6**	
Reliability Incentive Adjustment	C1	RIt	4.1	4.2	4.2	Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt	9.3	8.6	8.6	Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	1.4	1.6	1.6	Forecast
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**14.8**	**14.4**	**14.5**	
Network Innovation Allowance	D	NIAt	10.5	10.7	10.7	Forecast
Network Innovation Competition	E	NICFt	32.7	40.5	32.7	Forecast
Future Environmental Discretionary Rewards	F	EDRt	0.0	2.0	0.0	Forecast
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	Forecast
Scottish Site Specific Adjustment	H	DISt	6.6	0.0	0.0	Forecast
Scottish Terminations Adjustment	I	TSt	3.1	0.0	0.0	Forecast
Correction Factor	K	-Kt	-55.5	0.0	0.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2714.3**	**3010.2**	**2879.8**	
Pre-vesting connection charges	P		44.0	41.9	44.0	Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2670.3**	**2968.4**	**2835.8**	

Scottish Power Transmission revenue forecast

The Scottish Power Transmission revenue forecast will be updated in November for the draft tariffs, and will be finalised by 25 January 2019. The indicative SPT revenue to be collected via TNUoS for 2019/20 is £390m.

SHE Transmission revenue forecast

The Scottish Hydro Electric Transmission (SHE Transmission) revenue forecast will be updated in November for the draft tariffs, and will be finalised by 25 January 2019. The indicative SHET Transmission revenue to be collected via TNUoS for 2019/20 is £349m.

Offshore Transmission Owner & Interconnector revenues

The Offshore Transmission Owner revenue forecast will be updated in November for the draft tariffs, and will be finalised by 25 January 2019. The indicative OFTO revenue to be collected via TNUoS for 2019/20 is £386m, a significant increase of £68m (22%) from 2018/19. This is because we expect four OFTOs to transfer assets in 2019/20 (Walney 3 & 4, Galloper, Rampion and Race Bank).

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. The interconnector revenue forecast will be updated in November draft tariff forecast, and confirmed by 25 January 2019.

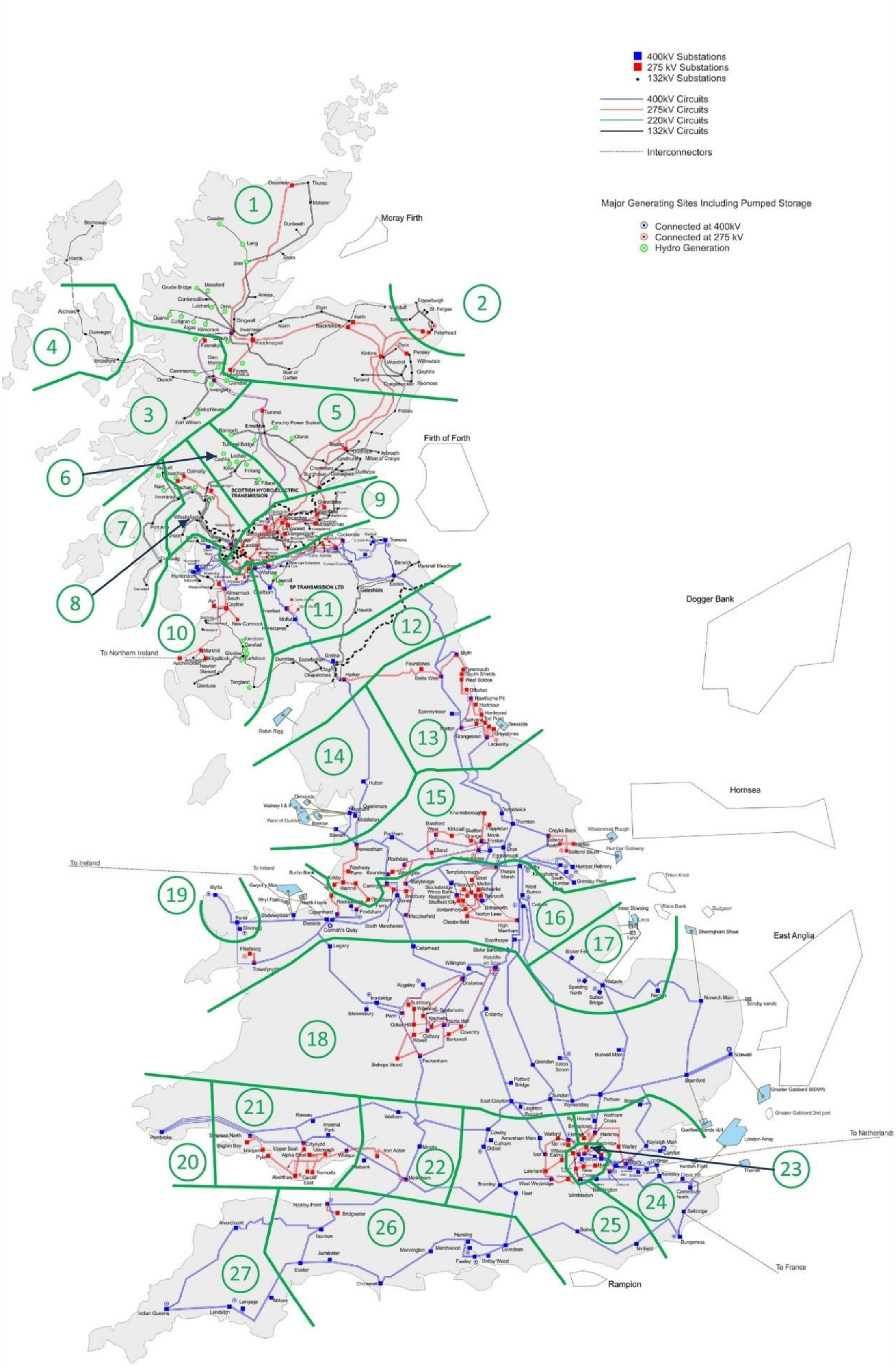
Table 27 - Offshore Transmission Owner revenues (indicative)

<table>
<tr><th>Offshore Transmission Revenue Forecast (£m)</th><th colspan="6">23/04/2018</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th><th>2017/18</th><th>2018/19</th><th>2019/20</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.3</td><td>6.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>7.4</td><td>7.8</td><td>7.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td>13.6</td><td>14.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.4</td><td>8.7</td><td>8.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>12.5</td><td>12.3</td><td>16.3</td><td>14.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td>20.7</td><td>21.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.2</td><td>12.6</td><td>13.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td>28.4</td><td>29.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.5</td><td>39.5</td><td>41.8</td><td>41.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>19.5</td><td>18.6</td><td>19.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.7</td><td>27.2</td><td>28.2</td><td>27.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>29.3</td><td>32.7</td><td>29.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>22.0</td><td>22.6</td><td>23.3</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td></td><td rowspan="2">29.3</td><td>9.7</td><td>12.1</td><td>12.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td></td><td>11.6</td><td>13.2</td><td>13.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2018/19</td><td></td><td></td><td></td><td>4.7</td><td>34.5</td><td>30.7</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2019/20</td><td></td><td></td><td></td><td></td><td></td><td>74.8</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2020/21</td><td></td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2021/22</td><td></td><td></td><td></td><td></td><td></td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>260.8</td><td>270.2</td><td>318.1</td><td>386.5</td><td></td></tr>
</table>

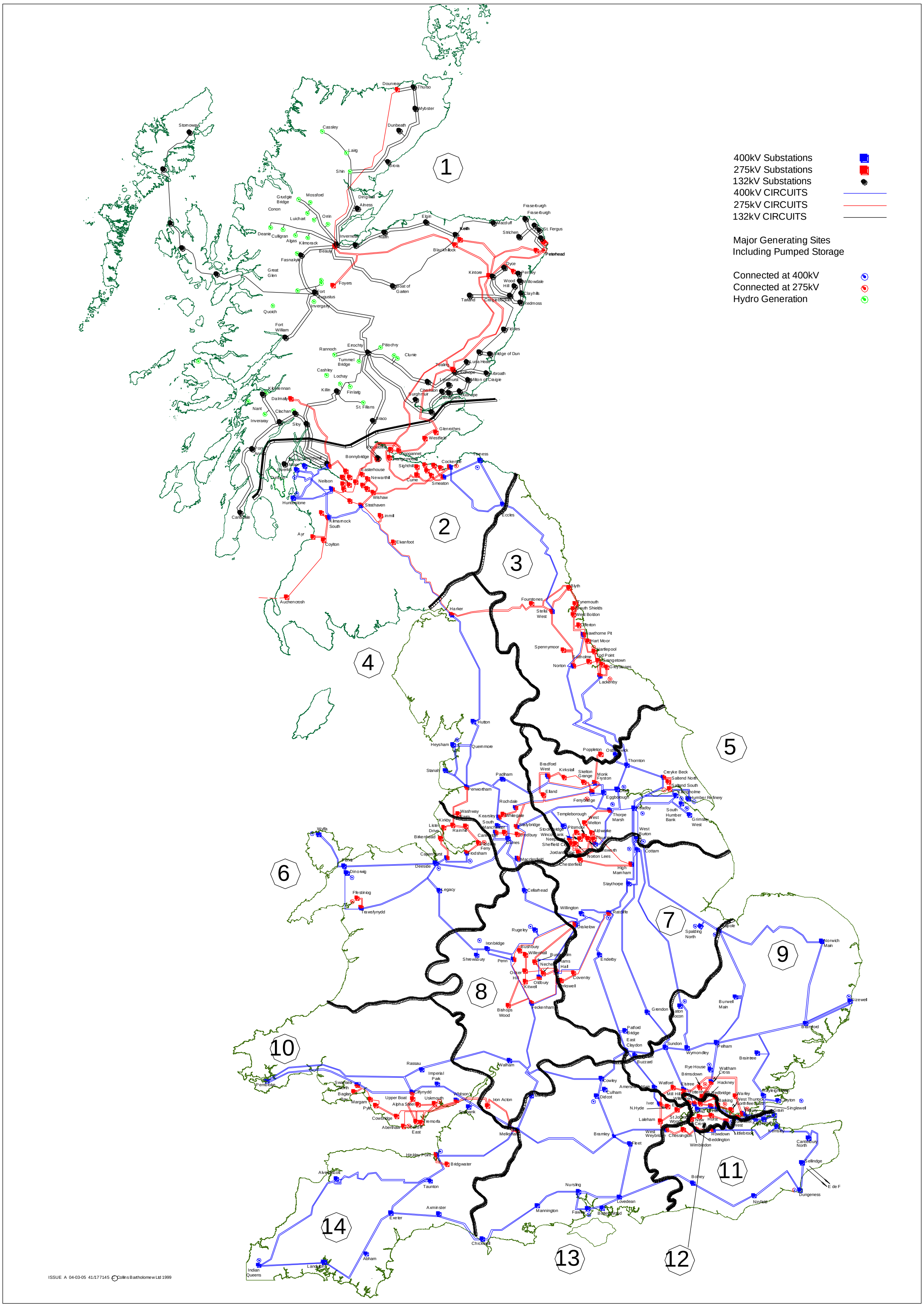
Note: Figures for historic years represent National Grid's forecast of OFTO revenues (including prevailing asset transfer date assumptions) at the time final tariffs for each year were calculated rather than our current best view.

Appendix G: Generation zones map

Figure A2: GB Existing Transmission System



Appendix H: Demand zones map



Appendix I: Parameters affecting TNUoS Tariffs

The following table summarises the various inputs to the tariff calculations, indicating which updates are provided in each forecast. Purple highlighting indicates that parameter will be fixed for that forecast.

We intend to fix the chargeable demand as early as practicable. However there has been increasing volatility in many of the inputs in recent years (for example, the high winter 2017/18 embedded export volume). This means we may need to adjust the values at a later date to ensure we set tariffs to recover the total allowed revenue.

		2019/20 TNUoS Tariff Forecast				
		November	April	June	November (Draft tariffs)	January (Final tariffs)
Methodology		Open to industry governance				
Locational	**DNO/DCC Demand Data**	Previous year			Week 24 updated	
	Contracted TEC	Latest TEC Register	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
	Network Model	Previous year (except local circuit changes)			Latest version based on ETYS	
Residual	**OFTO Revenue** *(part of allowed revenue)*	Forecast	Forecast	Forecast	Forecast	NG Best View
	Allowed Revenue *(non OFTO changes)*	Update financial parameters	Update financial parameters	Latest onshore TO Forecasts	Latest TO Forecasts	From TOs
	Demand Charging Bases	Previous Year	Revised Forecast	Final Forecast	*Only by exception*	*Only by exception*
	Generation Charging Base	NG Best View	NG Best View	NG Best View	NG Best View	NG Final Best View
	Generation ALFs	Previous Year			New ALFs published	
	Generation Revenue	Forecast	Forecast	Fixed Gen Rev £m		