

# Forecast TNUoS Tariffs for 2020/21

## National Grid Electricity System Operator

July 2019



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## Contact us

If you have any comments or questions on the contents or format of this report, please don't hesitate to get in touch with us. This report and associated documents can also be found on our website at [www.nationalgrideso.com/tnuos](http://www.nationalgrideso.com/tnuos)

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# Executive summary

**This document contains the July Forecast Transmission Network Use of System (TNUoS) Tariffs for 2020/21, which will become effective on 1 April 2020. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB transmission networks.**

The tariffs for 2020/21 were last forecast in March 2019.

## Total revenues to be recovered

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,939.3m in 2020/21. This is £11.5m less than the March forecast. This change is caused by updated financial parameters and corrections, and revised forecast for offshore transmission owners (OFTOs) revenue.

## Small Generator Discount

The Small Generator Discount is defined in National Grid's Electricity Transmission licence condition C13.

On 24 January 2019, Ofgem announced the result of a statutory consultation<sup>1</sup> that the Small Generator Discount would be extended until 31 March 2021.

The tariffs forecast for 2020/21 now include the effect of the Small Generator Discount:

- The discount affects transmission connected generation <100MW, connected at 132kV, and is £12.00/kW;
- Demand tariffs are increased by:
  - £0.74/kW for Gross HH, and
  - 0.095p/kWh for NHH.

**Demand tariffs in this report are inclusive of the effect of the Small Generator Discount.**

## Generation tariffs

The total revenue to be recovered from generation tariffs is £374.9m. This is a reduction since the March forecast, following recent publication of the Future Energy Scenarios (FES). This is to ensure that average annual generation tariffs remain

below the €2.50/MWh cap set by European Commission Regulation (EU) 838/2010 using the methodology defined in the Connection and Use of System Code (CUSC).

The chargeable TEC for 2020/21 is 71.8GW. This is a significant decrease since the March forecast, and is due to changes to the TEC register and our best view of generation. The average generation tariff is £5.22/kW. This is a decrease of £0.38/kW since the March forecast, due to the decrease in the generation revenue cap.

## Demand tariffs

The revenue to be recovered from demand tariffs is £2,564.3m in 2020/21. This value has increased by £28.6m since March tariffs.

The chargeable demand has been updated since our March forecast. We forecast a gross system peak of 50.4GW. Gross half-hourly (HH) demand is forecast to be 19.2GW and non-half-hourly (NHH) demand is forecast to be 24.3TWh. Embedded export volumes are forecast to be 7.2GW.

£17.2m will be payable through the Embedded Export Tariff (EET). This is a slight decrease since March tariffs due changes to locational tariffs.

Not including the effect of the Small Generator Discount, the average gross HH demand tariff is £51.49/kW. The average EET is £2.38/kW. The average NHH demand tariff is 6.55p/kWh. These demand tariffs have increased since the March tariffs, due to the increase in revenue to be collected from demand users.

## Drivers of changes since the last forecast

Following the latest Future Energy Scenario (FES) forecast, the total revenue to be collected from generators in year 2020/21 has now been finalised at £374.9m. This is a

<sup>1</sup>

[https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd\\_decision\\_letter\\_final.pdf](https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd_decision_letter_final.pdf)

reduction from the March forecast (£415.1m).

Compared to our March forecast, in general, generation tariffs are lower.

Demand tariffs are higher than in the March forecast, and the average demand tariff has increased by £0.37/kW.

### Changes to the charging methodology affecting 2020/21 tariffs

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

There have been no changes to the charging methodology since the March forecast.

### Next tariff publication

Our next TNUoS tariff publication will be the Draft 2020/21 tariffs.

We published our timetable of forecasts for TNUoS tariffs for 2020/21 earlier in January, and this is available on our website<sup>2</sup>.

### 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.

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<sup>2</sup><https://www.nationalgrideso.com/sites/eso/files/documents/Timetable%20of%20TNUoS%20forecasts%20for%202021.pdf>



## **Demand tariffs**

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

## 1. Demand tariffs summary

The tables in this section show demand tariffs for Half-Hourly (HH), Embedded Export (EET) and Non-Half-Hourly (NHH) metered demand.

The breakdown of the HH locational tariff into the peak and year round components can be found on page 40.

**Table 1 Summary of demand tariffs**

HH Tariffs	2020/21 March	2020/21 July	Change
Average Tariff (£/kW)	51.113949	51.487810	0.373861
Residual (£/kW)	52.178588	52.533607	0.355019
EET	2020/21 March	2020/21 July	Change
Average Tariff (£/kW)	2.524960	2.379074	-0.145886
Phased residual (£/kW)	0.000000	0.000000	0.000000
AGIC (£/kW)	3.426888	3.427086	0.000198
Embedded Export Volume (GW)	7.091124	7.230000	0.138876
Total Credit (£m)	17.904800	17.200703	-0.704097
NHH Tariffs	2020/21 March	2020/21 July	Change
Average (p/kWh)	6.524630	6.548735	0.024105

Please note that these average tariffs **DO NOT** include the additional levy for the Small Generator Discount scheme.

**Table 2 Demand tariffs**

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	24.098098	3.256229	0.000000
2	Southern Scotland	32.442288	4.163924	0.000000
3	Northern	42.615678	5.306694	0.000000
4	North West	49.649333	6.374698	0.000000
5	Yorkshire	49.885147	6.170694	0.039960
6	N Wales & Mersey	51.270718	6.400488	1.425532
7	East Midlands	53.418265	6.828395	3.573079
8	Midlands	54.712695	7.105347	4.867508
9	Eastern	55.300674	7.553600	5.455488
10	South Wales	50.773870	5.915328	0.928684
11	South East	57.672224	8.004151	7.827037
12	London	61.128120	6.358193	11.282933
13	Southern	59.071027	7.633628	9.225840
14	South Western	57.239363	7.968421	7.394177

Residual charge for demand:	£	52.533607	
Tariffs include small gen tariff of:	£	0.738666	0.0947450

Please note these tariffs **DO** include the effect of the Small Generator Discount, see page 25.

## 2. 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 now charged on a gross basis rather than net. A separate EET payment is made to embedded generators which generate over triad periods. Embedded exports, and small embedded generators do not pay generation TNUoS charges.

Demand tariffs have increased, due to the reduction generation revenue. As less revenue is collected from generators, the amount of revenue to be collected through demand tariffs has increased.

The average HH gross tariff is now £51.49/kW; compared to the March forecast, this has increased by £0.37/kW. The average NHH tariff is now 6.55p/kWh, an increase of 0.02p/kWh.

Please note this does not include the effect of the Small Generator Discount, which increases HH and NHH tariffs (see the HH and NHH tariffs sections below for more information).

The average EET is £2.38/kW which has decreased by £0.15/kW. The total revenue to be paid to embedded generators has decreased to £17.2m. This will be recovered through the demand tariffs.

## 3. Gross Half-Hourly demand tariffs

This table and chart show the gross HH demand tariffs for 2020/21 compared to the March 2019 forecast.

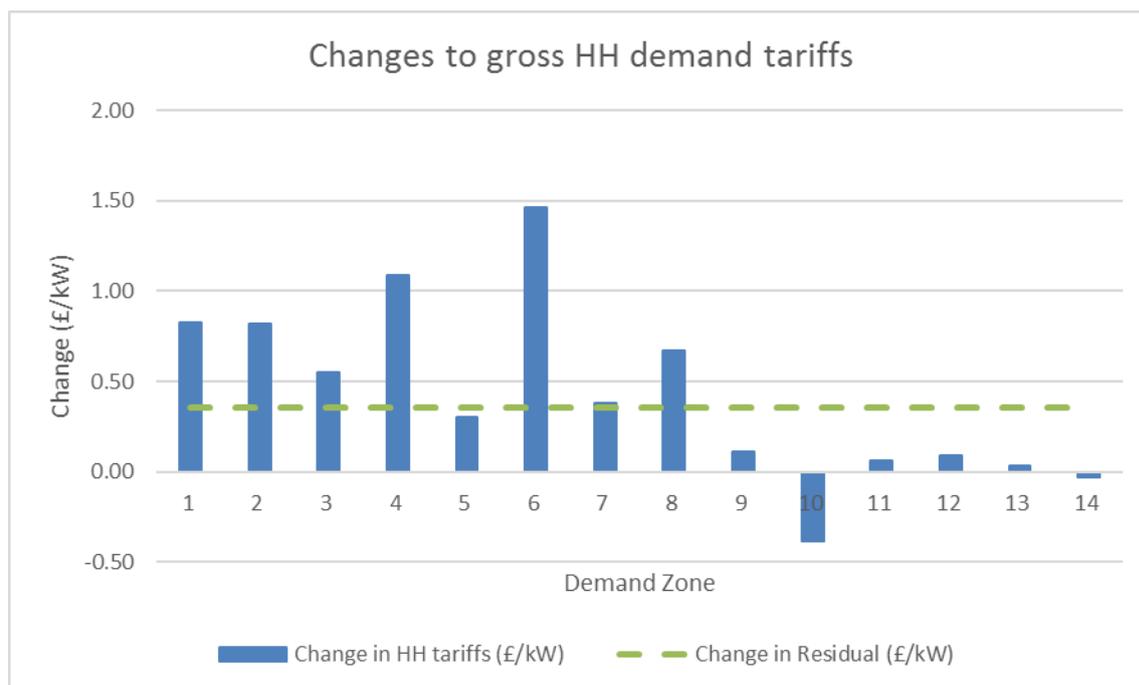
**Table 3 Gross Half-Hourly demand tariffs**

Zone	Zone Name	2020/21 March (£/kW)	2020/21 July (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	23.270040	24.098099	0.828059	0.355019
2	Southern Scotland	31.625764	32.442289	0.816525	0.355019
3	Northern	42.063198	42.615679	0.552481	0.355019
4	North West	48.561872	49.649334	1.087462	0.355019
5	Yorkshire	49.585248	49.885148	0.299900	0.355019
6	N Wales & Mersey	49.807097	51.270719	1.463622	0.355019
7	East Midlands	53.040333	53.418266	0.377933	0.355019
8	Midlands	54.044382	54.712696	0.668314	0.355019
9	Eastern	55.190257	55.300675	0.110418	0.355019
10	South Wales	51.156901	50.773871	-0.383030	0.355019
11	South East	57.607511	57.672225	0.064714	0.355019
12	London	61.038314	61.128121	0.089807	0.355019
13	Southern	59.036675	59.071028	0.034353	0.355019
14	South Western	57.273113	57.239364	-0.033749	0.355019

The breakdown of the locational elements of these tariffs is shown on page 40.

**Please note these tariffs DO include the effect of the Small Generator Discount, see page 25.**

**Figure 1 Changes to gross Half-Hourly demand tariffs**



The average HH gross demand tariff is £51.49/kW; this has increased by £0.37/kW compared to the March forecast. This is due to the decrease in revenue from generation, driven by the decrease in generation volume. Please note that the average HH gross demand tariff **does not** include the additional levy for the Small Generator Discount scheme. The level of gross HH chargeable demand has increased by 0.06GW since the March forecast and is now 19.2GW.

The additional levy for the Small Generator Discount scheme increases the tariffs by £0.74/kW.

#### 4. Embedded Export Tariffs (EET)

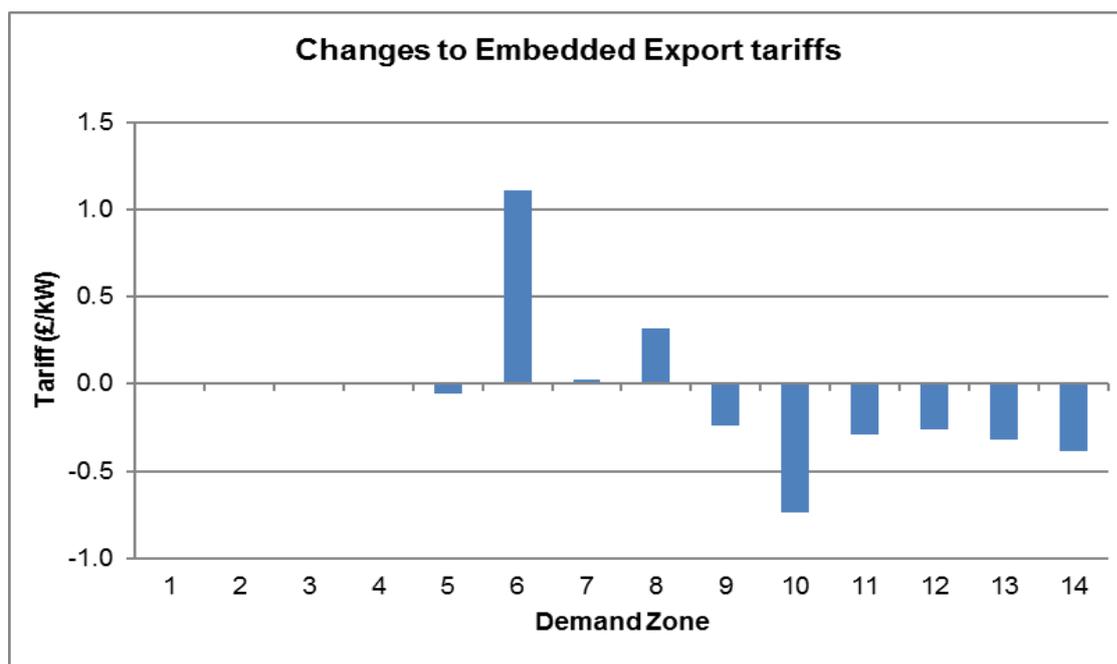
The next table and chart show the 2020/21 EET compared to the March 2019 forecast.

**Table 4 Embedded Export Tariffs**

Zone	Zone Name	2020/21 March (£/kW)	2020/21 July (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	0.000000	0.000000	0.000000
4	North West	0.000000	0.000000	0.000000
5	Yorkshire	0.092346	0.039960	-0.052386
6	N Wales & Mersey	0.314195	1.425532	1.111337
7	East Midlands	3.547431	3.573079	0.025648
8	Midlands	4.551480	4.867508	0.316028
9	Eastern	5.697355	5.455488	-0.241867
10	South Wales	1.663999	0.928684	-0.735315
11	South East	8.114609	7.827037	-0.287572
12	London	11.545412	11.282933	-0.262479
13	Southern	9.543773	9.225840	-0.317933
14	South Western	7.780211	7.394177	-0.386034

The breakdown of the locational elements of these tariffs is shown on page 40.

**Figure 2 Embedded export tariff changes**



The average EET has decreased by £0.14/kW to £2.38/kW since the March forecast. The EET charging base has increased from 7.1GW to 7.2GW and the forecasted EET revenue has decreased to £17.2m from £17.9m. The value of the AGIC (Avoided GSP Infrastructure Credit) has marginally increased since the March forecast.

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

In accordance with the methodology, the value of the EET has steadily reduced and from 2020/21 will be set at £0/kW. This is primarily a result of the phased reduction to the residual element of the EET, which is described in more detail in the September 2018 Five-Year View.<sup>3</sup> The result of this is that from 2020/21 we expect the EET to be £0/kW in demand zones 1 to 4.

See page 40 for a breakdown of the EET.

<sup>3</sup> <https://www.nationalgrid.com/sites/default/files/documents/Forecast%20from%202018-19%20to%202022-23%20%282%29.pdf> pp.14-15.

## 5. Non-Half-Hourly demand tariffs

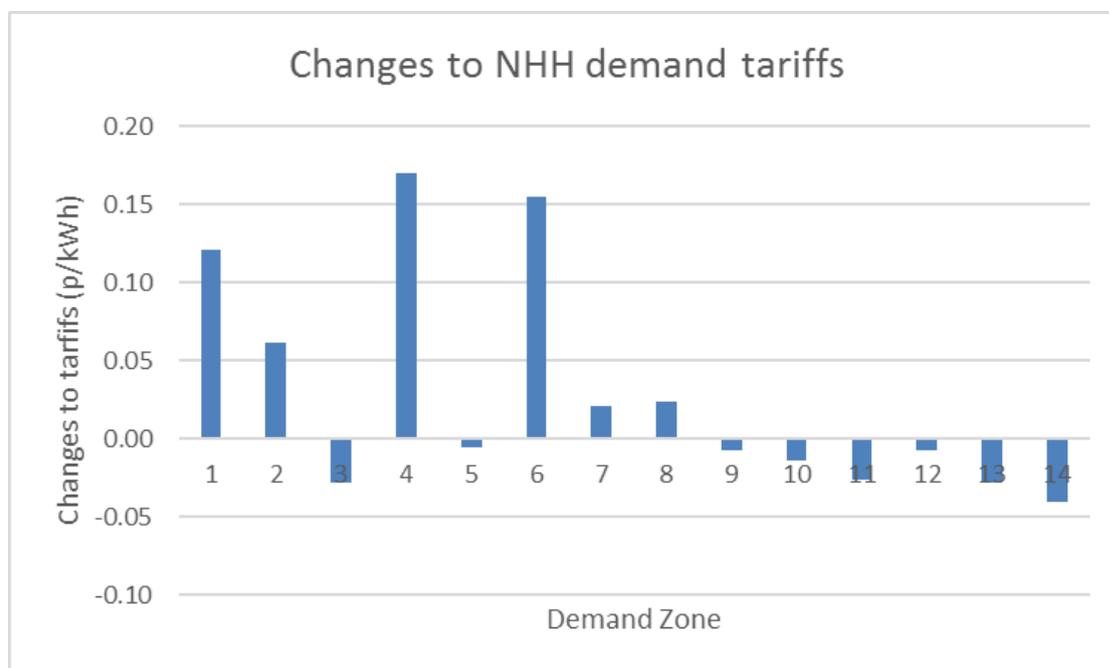
This table and chart show the difference between this forecast and the March 2019 forecast.

**Table 5 Changes to Non-Half-Hourly demand tariffs**

Zone	Zone Name	2020/21 March (p/kWh)	2020/21 July (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.135707	3.256229	0.120522
2	Southern Scotland	4.102770	4.163924	0.061154
3	Northern	5.334874	5.306694	-0.028180
4	North West	6.204346	6.374698	0.170352
5	Yorkshire	6.175672	6.170694	-0.004978
6	N Wales & Mersey	6.245607	6.400488	0.154881
7	East Midlands	6.807672	6.828395	0.020723
8	Midlands	7.081417	7.105347	0.023930
9	Eastern	7.561043	7.553600	-0.007443
10	South Wales	5.929393	5.915328	-0.014065
11	South East	8.030463	8.004151	-0.026312
12	London	6.365499	6.358193	-0.007306
13	Southern	7.661438	7.633628	-0.027810
14	South Western	8.008709	7.968421	-0.040288

Please note these tariffs DO include the effect of the Small Generator Discount, see page 25.

**Figure 3 Changes to Non-Half-Hourly demand tariffs**



The weighted average NHH tariff is 0.024p/kWh higher than in the March forecast. This is due to the overall increase in revenue to be recovered from demand because of the decrease in the generation charging base and locational elements. The impact of a larger demand charging base has restricted the amount by which the NHH tariffs have increased. So, this along with the changes to locational elements has caused the tariffs to drop in zones 9 to 14.



## **Generation tariffs**

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

## 6. Generation tariffs summary

This section summarises the forecasted generation tariffs for 2020/21, how these tariffs were calculated and how they have changed since the March forecast.

**Table 6 Summary of generation tariffs**

Generation Tariffs (£/kW)	2020/21 March	2020/21 July	Change since last forecast
Residual	-3.957024	-4.533397	-0.576373
Average Generation Tariff	5.600884	5.221001	-0.379883

The average generation tariff is calculated by dividing the total revenue payable by generation by the generation charging base in GW. These generation average tariffs include revenues from local tariffs.

Average generation tariffs have decreased by £0.380/kW. The generation residual has decreased by £0.576/kW due to the decrease in the generation revenue cap.

Please note these average generation tariffs DO NOT include the effect of the Small Generator Discount.

## 7. Generation wider tariffs

The following section summarises how the wider generation tariffs have changed between the March forecast and the July tariffs. The comparison uses example tariffs for Conventional Carbon generators with an Annual Load Factor (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 page 44.

The classifications for different technology types are below:

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

**Table 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	2.509772	19.998935	13.690826	-4.533500	24.928081	27.666246	17.156900	
2	East Aberdeenshire	4.903266	12.294034	13.690826	-4.533500	21.157654	23.895819	14.074940	
3	Western Highlands	1.940242	18.601534	13.514102	-4.533500	23.099251	25.802071	16.421216	
4	Skye and Lochalsh	1.891306	18.601534	19.731440	-4.533500	28.024185	31.970473	22.638554	
5	Eastern Grampian and Tayside	2.625204	16.623299	12.910179	-4.533500	21.718486	24.300522	15.025999	
6	Central Grampian	3.577688	15.839303	12.524474	-4.533500	21.735210	24.240104	14.326695	
7	Argyll	3.384611	12.789125	22.372573	-4.533500	26.980469	31.454984	22.954723	
8	The Trossachs	3.621464	12.789125	10.958434	-4.533500	18.086011	20.277698	11.540584	
9	Stirlingshire and Fife	2.259245	10.520872	10.175331	-4.533500	14.282707	16.317774	9.850180	
10	South West Scotland	2.963986	10.991890	10.293712	-4.533500	15.458968	17.517710	10.156968	
11	Lothian and Borders	3.580182	10.991890	5.097648	-4.533500	11.918312	12.937842	4.960904	
12	Solway and Cheviot	1.630786	6.835166	5.780323	-4.533500	7.189677	8.345742	3.980889	
13	North East England	3.715341	5.021680	3.744746	-4.533500	6.194982	6.943931	1.219918	
14	North Lancashire and The Lakes	1.391494	5.021680	0.765884	-4.533500	1.488045	1.641222	-1.758944	
15	South Lancashire, Yorkshire and Humber	4.617110	0.947497	0.135663	-4.533500	0.950138	0.977271	-4.018838	
16	North Midlands and North Wales	3.576522	-0.404080		-4.533500	-1.280242	-1.280242	-4.695132	
17	South Lincolnshire and North Norfolk	1.733259	0.014259		-4.533500	-2.788834	-2.788834	-4.527796	
18	Mid Wales and The Midlands	0.828113	0.675276		-4.533500	-3.165166	-3.165166	-4.263390	
19	Anglesey and Snowdon	5.214007	-0.768784		-4.533500	0.065480	0.065480	-4.841014	
20	Pembrokeshire	9.982190	-4.235618		-4.533500	2.060196	2.060196	-6.227747	
21	South Wales & Gloucester	6.762822	-4.295725		-4.533500	-1.207258	-1.207258	-6.251790	
22	Cotswold	3.444905	2.692191	-7.035534	-4.533500	-4.563269	-5.970376	-10.492158	
23	Central London	-6.008564	2.692191	-6.870292	-4.533500	-13.884545	-15.258603	-10.326916	
24	Essex and Kent	-3.958930	2.692191		-4.533500	-6.338677	-6.338677	-3.456624	
25	Oxfordshire, Surrey and Sussex	-1.324651	-2.611078		-4.533500	-7.947013	-7.947013	-5.577931	
26	Somerset and Wessex	-1.290503	-3.001818		-4.533500	-8.225457	-8.225457	-5.734227	
27	West Devon and Cornwall	0.368159	-5.403453		-4.533500	-8.488103	-8.488103	-6.694881	
Small Generator Discount (£/kW)					12.000027				

The 80% and 40% load factors used in this table are for illustration only. Tariffs for individual generators are calculated using their own ALF; see page 44 for specific ALFs.

Please note that the Small Generator Discount has been extended until 31 March 2021, see page 22 for more information.

## 8. Changes since the previous generation tariffs forecast

The following section provides details of the wider and local generation tariffs for 2020/21 and how these have changed compared with the March forecast.

### Generation wider zonal tariffs

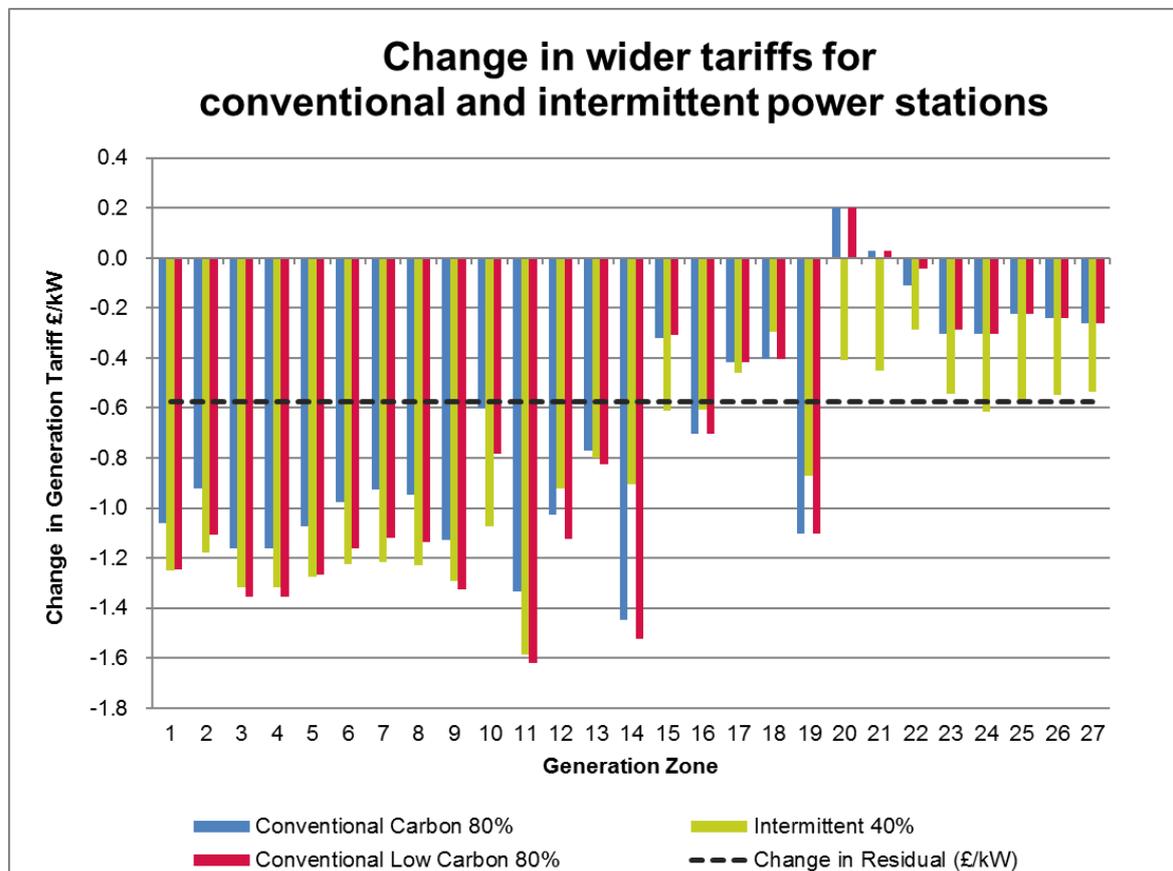
The next table and chart show the changes in wider generation TNUoS tariffs between the March forecast the July 2020/21 forecast.

**Table 8 Generation wider tariff changes**

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

Wider Generation Tariffs (£/kW)											
Zone	Zone Name	Conventional Carbon 80%			Conventional Low Carbon 80%			Intermittent 40%			Change in Residual (£/kW)
		2020/21 March (£/kW)	2020/21 July (£/kW)	Change (£/kW)	2020/21 March (£/kW)	2020/21 July (£/kW)	Change (£/kW)	2020/21 March (£/kW)	2020/21 July (£/kW)	Change (£/kW)	
1	North Scotland	25.986922	24.928081	-1.058842	28.911935	27.666246	-1.245689	18.405384	17.156900	-1.248484	-0.576476
2	East Aberdeenshire	22.079326	21.157654	-0.921672	25.004338	23.895819	-1.108519	15.252584	14.074940	-1.177645	-0.576476
3	Western Highlands	24.263102	23.099251	-1.163851	27.158637	25.802071	-1.356565	17.740649	16.421216	-1.319433	-0.576476
4	Skye and Lochalsh	29.185799	28.024185	-1.161614	33.324474	31.970473	-1.354000	23.956347	22.638554	-1.317793	-0.576476
5	Eastern Grampian and Tayside	22.792784	21.718486	-1.074297	25.567050	24.300522	-1.266528	16.303018	15.025999	-1.277019	-0.576476
6	Central Grampian	22.710436	21.735210	-0.975227	25.402941	24.240104	-1.162837	15.552431	14.326695	-1.225736	-0.576476
7	Argyll	27.908632	26.980469	-0.928163	32.572675	31.454984	-1.117691	24.172940	22.954723	-1.218217	-0.576476
8	The Trossachs	19.032964	18.086011	-0.946953	21.416234	20.277698	-1.138536	12.769075	11.540584	-1.228491	-0.576476
9	Stirlingshire and Fife	15.410702	14.282707	-1.127994	17.645620	16.317774	-1.327846	11.141158	9.850180	-1.290979	-0.576476
10	South West Scotlands	16.060595	15.458968	-0.601628	18.302927	17.517710	-0.785217	11.230120	10.156968	-1.073152	-0.576476
11	Lothian and Borders	13.251459	11.918312	-1.333147	14.556873	12.937842	-1.619031	6.545530	4.960904	-1.584626	-0.576476
12	Solway and Cheviot	8.215227	7.189677	-1.025550	9.469631	8.345742	-1.123889	4.902520	3.980889	-0.921630	-0.576476
13	North East England	6.967407	6.194982	-0.772425	7.768606	6.943931	-0.824675	2.020598	1.219918	-0.800680	-0.576476
14	North Lancashire and The Lakes	2.937723	1.488045	-1.449678	3.163884	1.641222	-1.522662	-0.854592	-1.758944	-0.904352	-0.576476
15	South Lancashire, Yorkshire and Humber	1.268771	0.950138	-0.318633	1.286687	0.977271	-0.309417	-3.407088	-4.018838	-0.611750	-0.576476
16	North Midlands and North Wales	-0.578714	-1.280242	-0.701528	-0.578714	-1.280242	-0.701528	-4.087968	-4.695132	-0.607164	-0.576476
17	South Lincolnshire and North Norfolk	-2.370128	-2.788834	-0.418705	-2.370128	-2.788834	-0.418705	-4.066501	-4.527796	-0.461295	-0.576476
18	Mid Wales and The Midlands	-2.761222	-3.165166	-0.403945	-2.761222	-3.165166	-0.403945	-3.968417	-4.263390	-0.294973	-0.576476
19	Anglesey and Snowdon	1.166403	0.065480	-1.100923	1.166403	0.065480	-1.100923	-3.968983	-4.841014	-0.872030	-0.576476
20	Pembrokeshire	1.861412	2.060196	0.198784	1.861412	2.060196	0.198784	-5.820009	-6.227747	-0.407738	-0.576476
21	South Wales & Gloucester	-1.237329	-1.207258	0.030071	-1.237329	-1.207258	0.030071	-5.802118	-6.251790	-0.449672	-0.576476
22	Cotswold	-4.454328	-4.563269	-0.108941	-5.926909	-5.970376	-0.043467	-10.204567	-10.492158	-0.287591	-0.576476
23	Central London	-13.582287	-13.884545	-0.302257	-14.970309	-15.258603	-0.288294	-9.781771	-10.326916	-0.545145	-0.576476
24	Essex and Kent	-6.032958	-6.338677	-0.305719	-6.032958	-6.338677	-0.305719	-2.841662	-3.456624	-0.614962	-0.576476
25	Oxfordshire, Surrey and Sussex	-7.721518	-7.947013	-0.225496	-7.721518	-7.947013	-0.225496	-5.010124	-5.577931	-0.567807	-0.576476
26	Somerset and Wessex	-7.985518	-8.225457	-0.239940	-7.985518	-8.225457	-0.239940	-5.187078	-5.734227	-0.547149	-0.576476
27	West Devon and Cornwall	-8.226714	-8.488103	-0.261389	-8.226714	-8.488103	-0.261389	-6.158228	-6.694881	-0.536653	-0.576476

**Figure 4 Variation in generation zonal tariffs**



Generation tariffs have decreased in all zones except zones 20 and 21, due to the change in the locational elements of the wider generation tariffs.

## Onshore local tariffs for generation

### 9. Onshore local substation tariffs

Local substation tariffs reflect the cost of the first transmission substation that each transmission connected generator connects to. They are increased each year by the average May to October RPI. These tariffs reflect forecast average RPI for the period May 2019 to October 2019, and so have slightly changed since the March forecast.

**Table 9 Local substation tariffs**

2020/21 Local Substation Tariff (£/kW)				
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.203903	0.116645	0.084046
<1320 MW	Redundancy	0.449181	0.277912	0.202119
>=1320 MW	No redundancy	n/a	0.365735	0.264501
>=1320 MW	Redundancy	n/a	0.600444	0.438274

### 10. 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 about a particular local circuit tariff, please feel free to contact us using the contact details on page 3.

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

Onshore local circuit tariffs have been updated with the latest RPI forecast, and the changes are minimal since the March forecast. Corrections to the circuit model have led to changes to a few generators. Onshore local circuit tariffs are listed in Table 10 here.

**Table 10 Onshore local circuit tariffs**

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Aberarder	1.122677	Dunhill	1.454640	Mark Hill	0.889211
Aberdeen Bay	2.647970	Dunlaw Extension	1.532468	Middle Muir	2.013076
Achruach	4.361059	Edinbane	6.952411	Middleton	0.148506
Aigas	0.664219	Ewe Hill	2.471790	Millennium Wind	1.854846
An Suidhe	3.091747	Fallago	0.444988	Moffat	0.193429
Arecleoch	2.109307	Farr	3.620972	Mossford	0.455179
Baglan Bay	0.772599	Fernoch	4.467227	Nant	-1.247656
Beinneun Wind Farm	1.525414	Ffestiniogg	0.256941	Necton	-0.373953
Bhlaraidh Wind Farm	0.655713	Finlarig	0.325189	New Deer	0.764721
Black Hill	1.577192	Foyers	0.297481	Rhigos	0.103359
Black Law	1.774604	Galawhistle	3.553628	Rocksavage	0.017980
BlackCraig Wind Farm	6.393155	Glendoe	1.868082	Saltend	0.017620
BlackLaw Extension	3.763278	Glenglass	4.886512	South Humber Bank	0.420047
Clyde (North)	0.111376	Gordonbush	0.234169	Spalding	0.286211
Clyde (South)	0.128801	Griffin Wind	9.864469	Strathbrora	0.102292
Corriearth	2.942188	Hadyard Hill	2.811027	Strathy Wind	1.898998
Corriemoillie	1.689674	Harestanes	2.567310	Stronelairg	1.087000
Coryton	0.052005	Hartlepool	0.207224	Wester Dod	0.485802
Cruachan	1.853318	Invergarry	0.371645	Whitelee	0.107783
Crystal Rig	0.140224	Kilgallioch	1.068849	Whitelee Extension	0.299637
Culligran	1.760195	Kilmorack	0.200570		
Deanie	2.891749	Kype Muir	1.506367		
Dersalloch	2.446348	Langage	0.667991		
Dinorwig	2.436671	Lochay	0.371645		
Dorenell	2.131341	Luichart	0.582438		
Dummaglass	1.625946	Marchwood	0.387579		

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

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

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Dyce 132kV	Aberdeen Bay 132kV	9.5km of Cable	9.5km of OHL	Aberdeen Bay
Crystal Rig 132kV	Wester Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
Farigaig 132kV	Corriearth 132kV	4km Cable	4km OHL	Corriearth
Elvanfoot 275kV	Clyde North 275kV	6.2km of Cable	6.2km of OHL	Clyde North
Elvanfoot 275kV	Clyde South 275kV	7.17km of Cable	7.17km of OHL	Clyde South
Farigaig 132kV	Dummaglass 132kV	4km Cable	4km OHL	Dummaglass
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

### 11. Offshore local generation tariffs

The local offshore tariffs (substation, circuit and Embedded Transmission Use of System) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed by average May to October RPI each year.

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

**Table 12 Offshore local tariffs 2020/21**

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	8.216650	42.989502	1.067488
Burbo Bank	10.645770	20.382774	0.000000
Dudgeon	15.421369	24.046095	0.000000
Greater Gabbard	15.405252	35.399752	0.000000
Gunfleet	17.782606	16.325825	3.051391
Gwynt Y Mor	18.761131	18.482033	0.000000
Humber Gateway	14.929571	33.686089	0.000000
Lincs	15.355556	60.120511	0.000000
London Array	10.452930	35.602097	0.000000
Ormonde	25.401467	47.320554	0.377105
Robin Rigg	-0.469893	31.126382	9.647499
Robin Rigg West	-0.469893	31.126382	9.647499
Sheringham Shoal	24.542221	28.782275	0.625641
Thanet	18.689792	34.825763	0.838379
Walney 1	21.922671	43.658942	0.000000
Walney 2	21.763233	44.043579	0.000000
West of Duddon Sands	8.459360	41.741699	0.000000
Westermost Rough	17.812569	30.131245	0.000000



**Updates to revenue and the charging model since the last forecast**

Since March, we have updated: allowed revenue forecast, generation revenue cap, the local circuits model, the generation background, demand charging bases and RPI forecast.

There will be no more changes to the £m revenue from generation tariffs.

We have updated some circuits. Circuits are required to simulate system flows in the transport model.

## 12.Changes affecting the locational element of tariffs

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

- Expected contracted generation and demand as of 31 October 2019;
- Local and MITS circuits; and
- RPI (which increases the expansion constant).

### Contracted and modelled TEC

Contracted TEC is the volume of TEC with connection agreements for the 2020/21 period, which can be found on the TEC register.<sup>4</sup> Modelled TEC is the amount of TEC we have entered into the Transport model to calculate system flows, which includes interconnector TEC.

Chargeable TEC is our best view of the likely volume of generation that will be connected to the system during 2020/21 and liable to pay generation TNUoS charges. Chargeable TEC volumes are always based on NGENSO's best view of the likely volume of generation TEC connected to the system in the relevant charging year.

Chargeable TEC has reduced by 2.3GW to 71.8GW since the March forecast.

The contracted TEC volumes used in this forecast were based on the TEC register from June 2019. 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.

**Table 13 Contracted TEC**

Generation (GW)	2019/20 Final Tariffs	2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
Contracted TEC	80.6	90.8	84.3		
Modelled Best View TEC	80.6	82.6	80.7		
Chargeable TEC	73.3	74.1	71.8		

## 13.Adjustments for interconnectors

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

<sup>4</sup> See the Registers, Reports and Updates section at <https://www.nationalgrid.com/uk/electricity/connections/after-you-have-connected>

The table below reflects the contracted position of interconnectors for 2020/21 in the interconnector register as of May 2019.

**Table 14 Interconnectors**

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	1020	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
IFA2 Interconnector	Chilling 400KV Substation	France	26	0	1100	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	637	0
NS Link	Blyth	Norway	13	0	1400	0

## 14.RPI

The RPI index for the components detailed below is calculated based on the forecast average May to October RPI for 2019. Because of this, they have changed slightly since the March forecast.

## 15.Expansion Constant

The expansion constant is 14.988818. This reflects the latest view of RPI, and has increased slightly since the March forecast.

## 16.Onshore substation and offshore substation tariffs

Local onshore substation tariffs and offshore substation tariffs are indexed by the average May to October RPI, so have been updated to take into account an updated RPI forecast.

## 17.Allowed revenues

NGESO recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Some other fundings (for example, Network Innovation Competition) are also collected from network users via TNUoS. The total amount recovered is adjusted for interconnector revenue recovery or redistribution (based on adjustments to account for the Cap and Floor regime and contributions from the IFA Use of Revenues framework).

Compared to the March forecast, tariffs have now been calculated to recover £2,939.3m of revenue, a decrease of £11.5m. This is mainly due to revised financial parameters forecast and corrections, and revised OFTO revenue forecast.

**Table 15 Allowed revenues**

£m Nominal	2020/21 TNUoS Revenue			
	March Forecast	July Forecast	Nov Draft	Jan Final
<b>National Grid Electricity Transmission</b>				
<i>Price controlled revenue</i>	1782.4	1777.7		
<i>Less income from connections</i>	31.0	31.0		
<b>NGET Income from TNUoS</b>	<b>1,751.4</b>	<b>1,746.7</b>		
<b>Scottish Power Transmission</b>				
<i>Price controlled revenue</i>	381.6	379.7		
<i>Less income from connections</i>	12.9	12.9		
<b>SPT Income from TNUoS</b>	<b>368.7</b>	<b>366.8</b>		
<b>SHE Transmission</b>				
<i>Price controlled revenue</i>	361.6	360.0		
<i>Less income from connections</i>	3.4	3.4		
<b>SHE Income from TNUoS</b>	<b>358.2</b>	<b>356.6</b>		
<b>National Grid Electricity System Operator</b>				
<b>Other Pass-through from TNUoS</b>	41.4	41.7		
<b>Offshore (offset by IFA contribution)</b>	431.0	427.4		
<b>Total to Collect from TNUoS</b>	<b>2,950.8</b>	<b>2,939.3</b>		

Please note these figures are rounded to one decimal place.

## 18. Generation / Demand (G/D) Split

The G/D split has reduced since the March tariff forecast. The proportion of revenue to be recovered from generation is now 12.8% of total revenue.

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 TNUoS charging methodology, the exchange rate for 2020/21 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2019. The value published is €1.119217/£.

### Generation Output

The forecast output of generation is 199.8TWh. This figure has been updated using the average of the four scenarios in the latest Future Energy Scenarios publication, using April to March data.

### Error Margin

The error margin remains unchanged from the March forecast at 16%. The parameters used to calculate the proportions of revenue collected from generation and demand are shown in the table below.

**Table 16 Generation and demand revenue proportions**

		2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50		
y	Error Margin	16.0%	16.0%		
ER	Exchange Rate (€/£)	1.12	1.12		
MAR	Total Revenue (£m)	2950.8	2,939.3		
GO	Generation Output (TWh)	221.2	199.8		
G	% of revenue from generation	14.1%	12.8%		
D	% of revenue from demand	85.9%	87.2%		
G.R	Revenue recovered from generation (£m)	415.1	374.9		
D.R	Revenue recovered from demand (£m)	2535.7	2564.3		

## 19. Charging bases for 2020/21

### 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 due to closure, termination or delay. It also includes any generators that we believe may increase their TEC.

We are unable to break down our best view of generation as some of the information used to derive it could be commercially sensitive. The 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 March tariff forecast to take into account the metering data for the full year of 2018/19.

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

- Historical gross metered demand and embedded export volumes (August 2014-March 2019)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

Following our review of the metered demand and export data, we have seen a relatively high level of embedded export volumes over triads in 2018/19 compared to previous years. We also recognise there will be an expected demand shift between NHH to HH under BSC modification P339 (see page 38 for more information). These changes in our outturn charging base have been factored into our projections for 2020/21.

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. But due to the increase in electric vehicles and heat pumps will begin to gradual increase again in future years.

**Table 17 Charging bases**

Charging Bases	2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
Generation (GW)	74.1	71.8		
NHH Demand (4pm-7pm TWh)	24.1	24.3		
<b>Net Charging</b>				
Total Average Net Triad (GW)	43.2	43.2		
HH Demand Average Net Triad (GW)	12.1	12.0		
<b>Gross charging</b>				
Total Average Gross Triad (GW)	50.2	50.4		
HH Demand Average Gross Triad	19.2	19.2		
Embedded Generation Export (GW)	7.1	7.2		

## 20. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast we have used the final version of the 2019/20 ALFs, based upon data from 2013/14 to 2017/18 available from the National Grid ESO website.<sup>5</sup>

## 21. Generation and demand residuals

The residual element of tariffs can be calculated using the formulae 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)

<sup>5</sup><https://www.nationalgrideso.com/sites/eso/files/documents/Final%20ALFs%20for%202019-20.pdf>

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

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

Where:

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

$Z_G$ ,  $Z_D$ ,  $L_C$ , and  $EE$  are determined by the locational elements of tariffs. The  $EE$  is also affected by the value of the AGIC<sup>6</sup> and phased residual.

**Table 18 Residual components calculation**

	Component	2020/21 March	2020/21 July	2020/21 Draft	2020/21 Final
<b>G</b>	Proportion of revenue recovered from generation (%)	14.1%	12.8%		
<b>D</b>	Proportion of revenue recovered from demand (%)	85.9%	87.2%		
<b>R</b>	Total TNUoS revenue (£m)	2,951	2,939		
<b>Generation Residual</b>					
<b>R<sub>G</sub></b>	Generator residual tariff (£/kW)	-3.96	-4.53		
<b>Z<sub>G</sub></b>	Revenue recovered from the locational element of generator tariffs (£m)	331.71	326.39		
<b>O</b>	Revenue recovered from offshore local tariffs (£m)	339.12	337.45		
<b>L<sub>G</sub></b>	Revenue recovered from onshore local substation tariffs (£m)	19.4	18.8		
<b>S<sub>G</sub></b>	Revenue recovered from onshore local circuit tariffs (£m)	18.1	17.9		
<b>B<sub>G</sub></b>	Generator charging base (GW)	74.1	71.8		
<b>Gross Demand Residual</b>					
<b>R<sub>D</sub></b>	Demand residual tariff (£/kW)	52.2	52.5		
<b>Z<sub>D</sub></b>	Revenue recovered from the locational element of demand tariffs (£m)	-68.2	-66.2		
<b>EE</b>	Amount to be paid to Embedded Export Tariffs (£m)	17.9	17.2		
<b>B<sub>D</sub></b>	Demand Gross charging base (GW)	50.2	50.4		

## 22.Small Generator Discount

The Small Generator Discount is defined in National Grid's Electricity Transmission licence condition C13. This licence condition was due to expire on 31 March 2019, but the deadline has now been extended to 31 March 2021<sup>7</sup> following an Ofgem statutory consultation<sup>8</sup> on the proposal.

A discount will continue to be applied to TNUoS tariffs for transmission connected generation <100MW, connected at 132kV until 31 March 2021.

**These Final tariffs now include the effect of the Small Generator Discount:**

- The discount to affected small generators is £12.000027/kW

<sup>6</sup> Avoided Grid Supply Point Infrastructure Credit

<sup>7</sup> [https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd\\_decision\\_letter\\_final.pdf](https://www.ofgem.gov.uk/system/files/docs/2019/01/sgd_decision_letter_final.pdf)

<sup>8</sup> <https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-our-proposal-modify-standard-licence-condition-c13-adjustment-use-system-charges-small-generators-electricity-transmission-licence>

- The additional tariff to add to all demand tariffs:
  - HH: £0.738666/kW, and
  - NHH: 0.094745p/kWh.

**Table 19 Small Generator Discount calculation**

Small Generator Discount calculation		
Generator Residual (£/kW)	G	-4.53
Demand Residual (£/kW)	D	52.53
Small Generator Discount (£/kW)	$T = (G + D)/4$	£ 12.00
Forecast Small Generator Volume (kW)	V	3,102,390
2019/20 Final SGD cost (£)	$V \times T$	37,228,764
Prior year reconciliation (£)	R	-
Total SGD Cost (£)	$C = (V \times T) - R$	37,228,764
Total System Triad Demand (kW)	TD	50,400,000
Total HH Triad Demand (kW)	HHD	19,218,690
Total NHH Consumption (kWh)	NHHD	24,310,000,000
Increase in HH Demand tariff (£/kW)	$HHT = C/TD$	0.738666
Total Cost to HH Customers (£)	$HHC = HHT \times HHD$	14,196,192
Increase in NHH Demand tariff (p/kWh)	$NHHT = (C - HHC)/NHHD$	0.094745
Total Cost to NHH Customers (£)	$NHHC = NHHT \times NHHD$	23,032,572

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



## **Tools and supporting information**

# Further information

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

## Charging webinars

We will hold a webinar for the July 2020/21 Forecast on Thursday 8 August 2019 from 10:30 to 11:30. 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 this tariffs report.

## Charging model copies available

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

## Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website under 2020/21 forecasts:

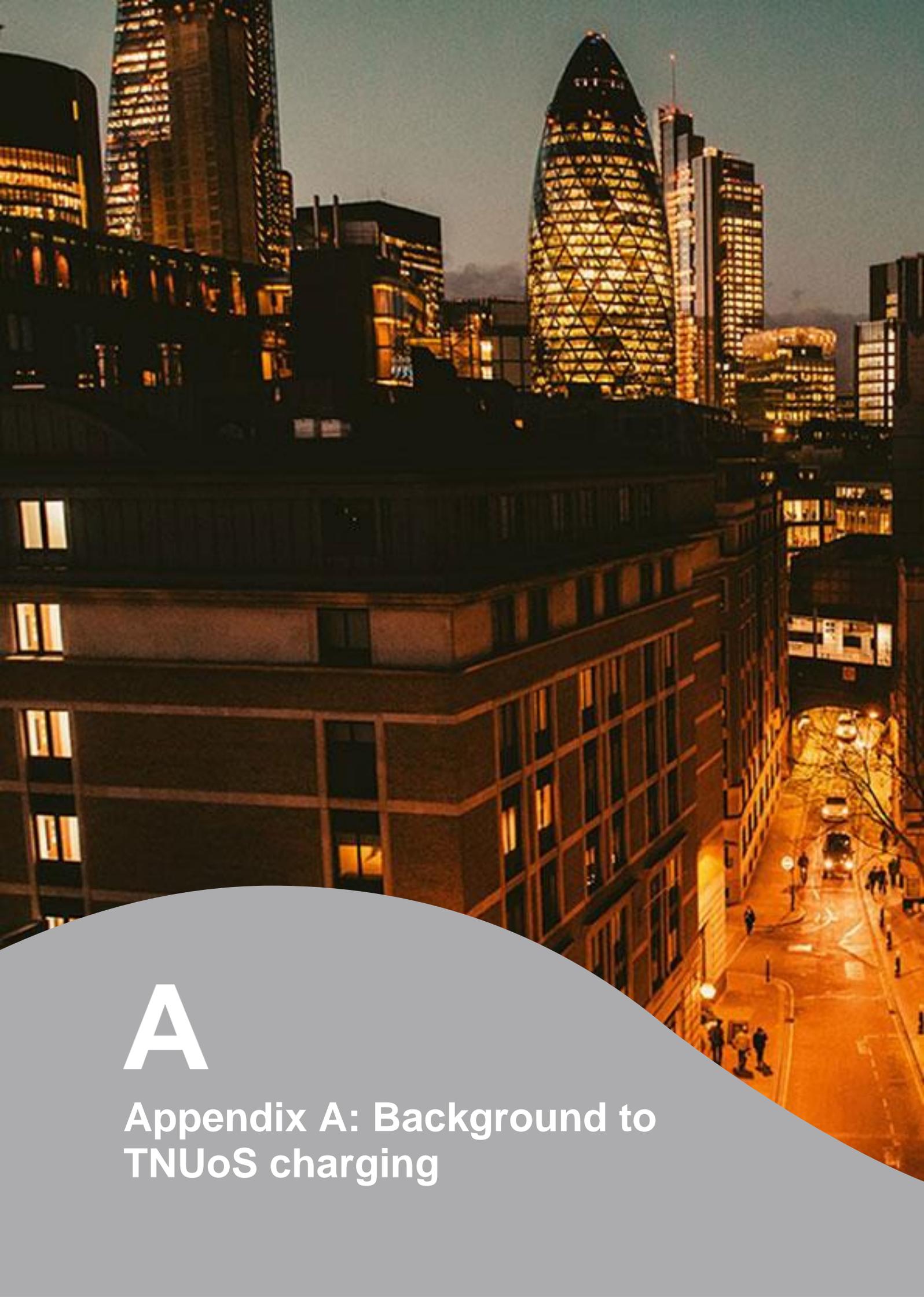
<https://www.nationalgrideso.com/tnuos>

## Contact Us

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# A

## Appendix A: Background to TNUoS charging

## Background to TNUoS charging

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

To reflect the cost of connecting in different parts of the network, NGENSO 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.

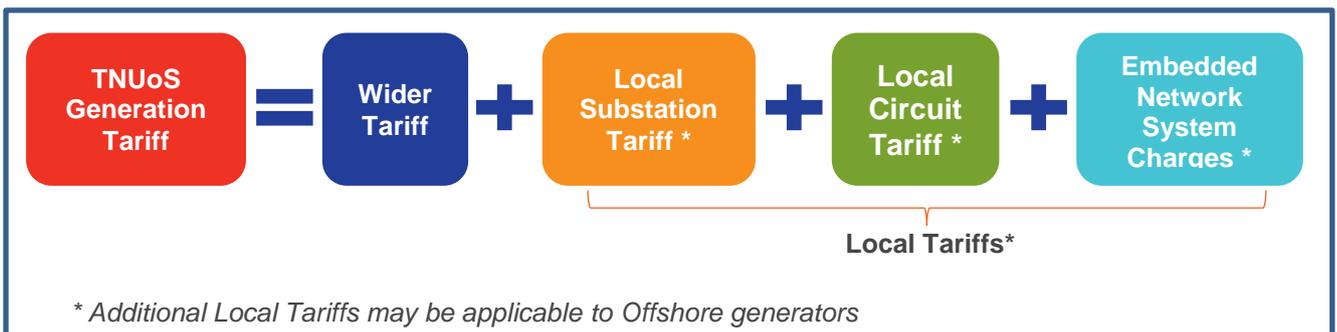
## Generation charging principles

Generators pay TNUoS (Transmission Network Use of System) tariffs to allow NGENSO 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.

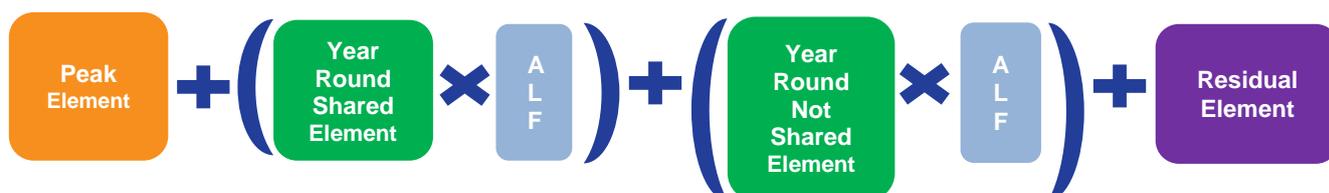
\*Embedded network system charges are only payable by generators that are not directly connected to the transmission network and are not applicable to all generators.

### 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.

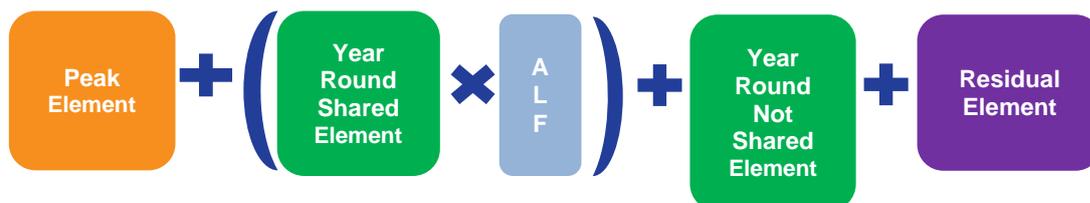
### Conventional Carbon Generators

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



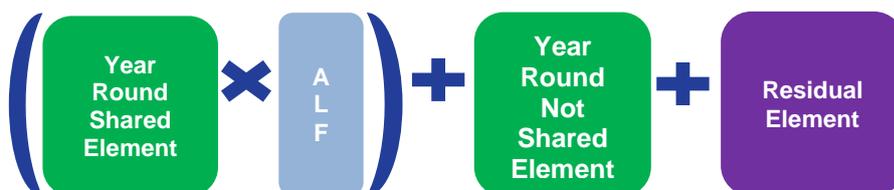
### Conventional Low Carbon Generators

(Hydro, Nuclear)



### Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

The ALFs used in these tariffs are listed from page 44.

## 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<sup>9</sup> if they want to export power onto the transmission system from the distribution network. Generators will incur local DUoS<sup>10</sup> 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.<sup>11</sup>

## Billing

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

The calculation for TNUoS generator monthly liability is as follows:

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

Number of months remaining in the charging year

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

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

## Generators with negative TNUoS tariffs

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

The value used for this reconciliation is the average output of the individual generator over the three settlement periods of highest output between 1 November and the end of February of the

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<sup>9</sup> Bilateral Embedded Generation Agreement. For more information about connections, please visit our website:

<https://www.nationalgrid.com/uk/electricity/connections/applying-connection>

<sup>10</sup> Distribution network Use of System charges

<sup>11</sup> These specific charges include any onshore local circuit and substation charges.

relevant charging year. Each settlement period must be separated by at least ten clear days. Each peak is capped at the amount of TEC held by the generator, so this number cannot be exceeded.

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

## Demand charging principles

Demand is charged in different ways depending on how the consumption is settled. HH demand customers 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.<sup>12</sup> 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 NGESO website. The tariff is charged on a £/kW basis.

There is a guide to triads and HH charging available on our website<sup>13</sup>.

## Embedded Export Tariffs (EET)

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

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

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

For more information on forecasts and billing, please see our guide for new suppliers on our website<sup>14</sup>.

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

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

## NHH demand tariffs

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

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

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<sup>12</sup> <https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads>

<sup>13</sup> <https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads>

<sup>14</sup> <sup>14</sup> <https://www.nationalgrideso.com/charging/charging-policy-and-guidance#triads>



# B

## Appendix B: Changes and proposed changes to the charging methodology

## Changes and proposed changes to the charging methodology for 2020/21 and future years

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2020/21 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.nationalgrideso.com/uk/electricity/codes/connection-and-use-system-code?mods>

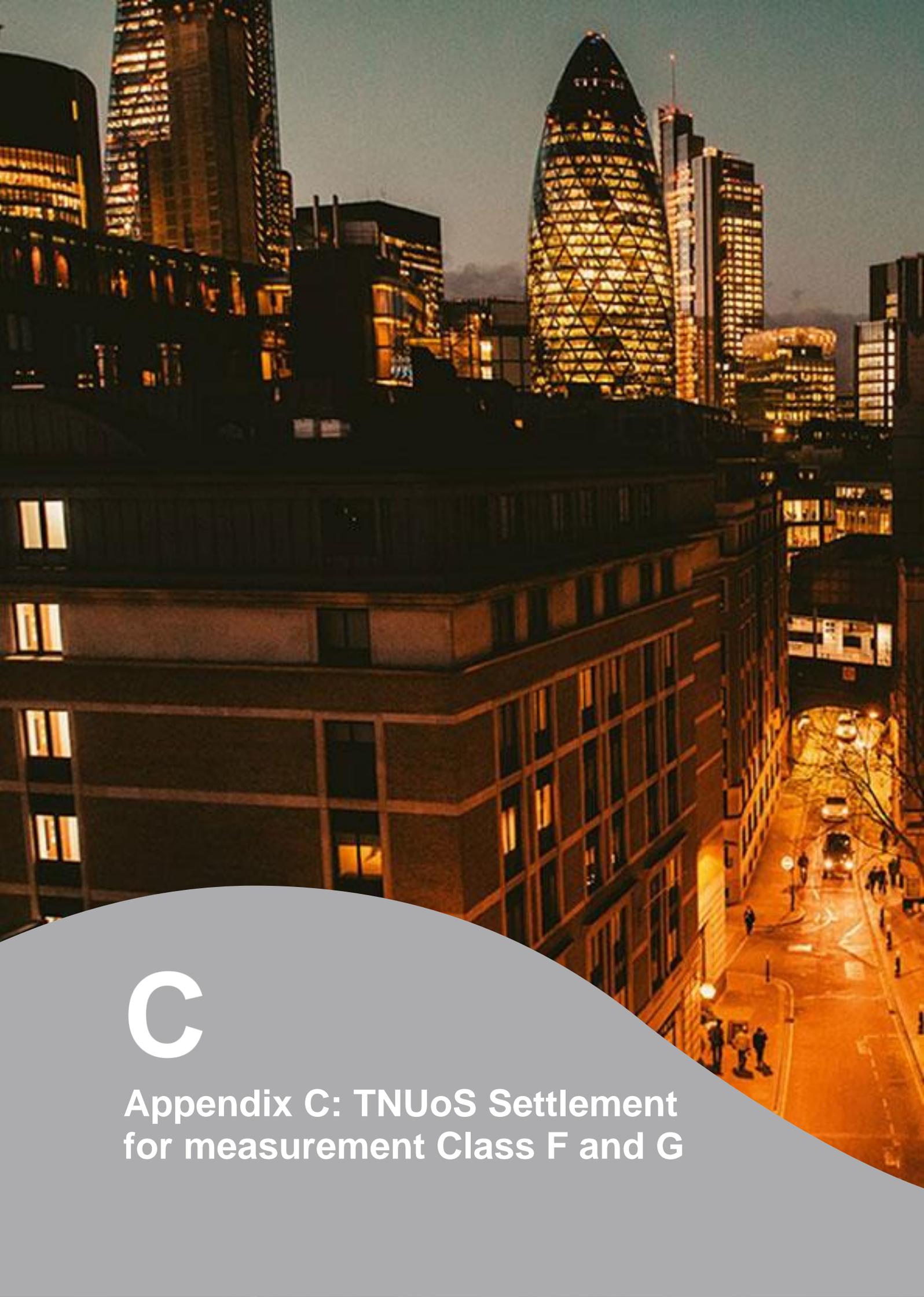
A summary of the modifications already in progress which could affect the 2020/21 TNUoS tariffs and their status are listed below.

Other modifications may be raised throughout the year which may impact tariffs for 2020/21.

**Table 20 Summary of in-flight CUSC modification proposals**

Name	Title	Effect of proposed change	Possible implementation
<a href="#">CMP280</a>	'Creation of a New Generator TNUoS Demand Tariff which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users'	Change the structure of demand TNUoS charges applied to storage and, potentially other generators.	April 2021
<a href="#">CMP286</a>	Improving TNUoS Predictability through Increased Notice of the Target Revenue used in the TNUoS Tariff Setting Process v1	Fixes target revenue to be recovered from the TNUoS setting process earlier, to provide more stability to future tariffs.	April 2021
<a href="#">CMP287</a>	Improving TNUoS Predictability Through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process.	Fixes parameters associated with the TNUoS setting process earlier, to provide more stability to future tariffs.	April 2021
<a href="#">CMP292</a>	Introducing a Section 8 cut-off date for changes to the Charging Methodologies	Introduces a cut off for changes to the charging methodologies to bring more stability and predictability to following years' charges	September 2019
<a href="#">CMP301</a>	Clarification on the treatment of project costs associated with HVDC and subsea circuits	Clarification of the legal text to ensure that it is clear that AC substation costs are not included in the circuit expansion factor calculation for HVDC and subsea circuits. We already calculate in this manner.	Implemented, No impact on charges
<a href="#">CMP303</a>	Improving local circuit charge cost-reflectivity	Remove some of the cost of the HVDC and subsea circuits from the calculation of the local circuit, reducing the local circuit tariffs for these circuits.	April 2020, no immediate impact on charges
<a href="#">CMP306</a>	Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital	Potentially reduce the 2021/22 TNUoS revenue by less than £20m due to a one-off adjustment	April 2021
<a href="#">CMP310</a>	CUSC section 14 changes in the event the UK leaves the EU without an agreement	Modify existing references to EU regulations to reflect the changes as foreseen in the relevant Statutory Instruments.	As soon as practicable following UK's exit from the EU, in the event no agreement is in place

<a href="#">CMP311</a>	Reassessment of User's Allowed Credit for Suppliers	To reassess User Allowed Credit" as defined in Section 3, Part III section 3.27 of the CUSC due to the large scale of liabilities this creates	April 2020
<a href="#">CMP312</a>	Correcting erroneous legal text in Section 14 following implementation of CMPs 264/5 (consequential)	Address the issue caused to Generator Users liable for demand TNUoS charges which has been created through a clear error in the approved legal text for CMPs 264/5.	Implemented
<a href="#">CMP315</a>	Review of the expansion constant	Review how the expansion constant is determined such that it best reflects the costs involved.	The first complete charging year following approval, if approved
<a href="#">CMP317</a>	Identification and exclusion of Assets Required for Connection when setting TNUoS charges	removal of revenue linked to "generator only spurs" from the calculation of generation revenue cap under the EU rules.	April 2021 to start phased implementation, if approved
<a href="#">CMP318</a>	Maintaining NHH charging arrangements for Measurement Classes F and G	extending the NHH TNUoS treatment for Classes F&G customers to year 2020/21 and beyond.	April 2020



# C

## Appendix C: TNUoS Settlement for measurement Class F and G

## TNUoS settlement for measurements classes F and G for 2020/21

All demand meters in GB are divided into classifications of capacity and HH/NHH functionality. Due to the rollout of smart meters which can record data on a HH basis, several of these classes are changing from being settled as NHH to being settled HH. This will change the TNUoS demand tariff they are liable to pay.

- HH treated demand is charged average triad consumption in £/kW
- NHH treated demand is charged on annual 4pm-7pm consumption in p/kWh

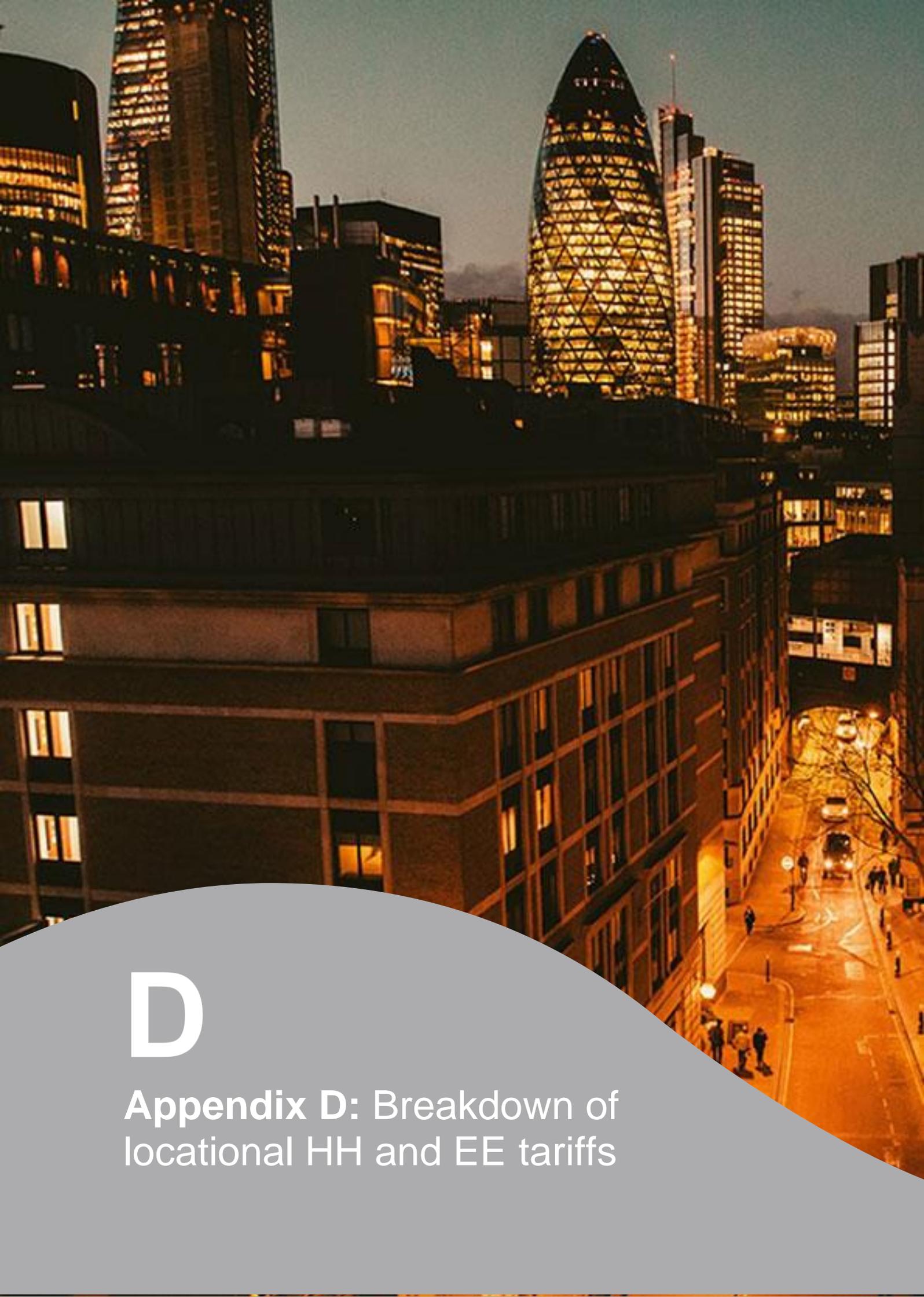
The two classes principally affected by this change are classes F and G, which typically cover large properties. The detailed CUSC text can be found at 14.17.29.8 – 11.<sup>15</sup>

The table below shows the classes, their specifications, and how they will be settled in 2019/20 and 2020/21.

Measurement class	Description	Settlement in 2019/20	2020/21 onwards
A	Non-Half Hourly metered	NHH	NHH
B	Non-Half Hourly unmetered	NHH	NHH
C	Half Hourly metered in 100kW premises	HH	HH
D	Half Hourly unmetered	HH	HH
E	Half Hourly metering equipment below 100kW with current transformer	HH	HH
F	Half Hourly metering equipment below 100kW with current transformer or whole current, at domestic premises	NHH	HH
G	Half Hourly metering equipment below 100kW with current transformer or whole current, NOT at domestic premises	NHH	HH

Note a CUSC modification proposal (CMP318) has been raised, to extend the NHH TNUoS treatment for Class F and Class G customers to year 2020/21 and beyond.

<sup>15</sup> <https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc?code-documents>



# D

## Appendix D: Breakdown of locational HH and EE tariffs

## Breakdown of HH and EET locational tariffs

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

**Table 21 HH locational tariffs**

Zone	2020/21		2020/21 July		Changes	
	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-2.481733	-27.168018	-2.224713	-26.949461	0.257019	0.218557
2	-2.296205	-18.997821	-2.048723	-18.781262	0.247481	0.216560
3	-3.486690	-7.369902	-3.417947	-7.238647	0.068743	0.131255
4	-1.557224	-2.800693	-0.993447	-2.629492	0.563777	0.171201
5	-2.400153	-0.934389	-2.521422	-0.865703	-0.121270	0.068686
6	-2.719694	-0.392999	-1.896626	-0.104928	0.823067	0.288071
7	-2.219788	2.340331	-2.112883	2.258876	0.106905	-0.081455
8	-2.085716	3.210308	-1.745226	3.185648	0.340490	-0.024660
9	1.582745	0.687722	1.498903	0.529498	-0.083841	-0.158223
10	-6.391328	4.628439	-6.773399	4.274997	-0.382071	-0.353442
11	4.322971	0.364750	3.985662	0.414289	-0.337309	0.049539
12	6.194452	1.924072	5.885575	1.970272	-0.308877	0.046200
13	1.944826	4.172059	1.692800	4.105955	-0.252027	-0.066105
14	-0.997360	5.350683	-1.243175	5.210266	-0.245815	-0.140418

This table shows the breakdown of the components that make up the EET.

**Table 22 Breakdown of the EET**

Demand Zone		2020/21 March			2020/21 July			Changes		
		Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)	Locational (£/kW)	AGIC (£/kW)	Phased Residual (£/kW)
1	Northern Scotland	-29.649750	3.426888	0.00	-29.174175	3.427086	0.00	0.475576	0.000198	0.00
2	Southern Scotland	-21.294026	3.426888	0.00	-20.829985	3.427086	0.00	0.464041	0.000198	0.00
3	Northern	-10.856592	3.426888	0.00	-10.656594	3.427086	0.00	0.199998	0.000198	0.00
4	North West	-4.357918	3.426888	0.00	-3.622940	3.427086	0.00	0.734978	0.000198	0.00
5	Yorkshire	-3.334542	3.426888	0.00	-3.387126	3.427086	0.00	-0.052584	0.000198	0.00
6	N Wales & Mersey	-3.112693	3.426888	0.00	-2.001554	3.427086	0.00	1.111138	0.000198	0.00
7	East Midlands	0.120543	3.426888	0.00	0.145993	3.427086	0.00	0.025450	0.000198	0.00
8	Midlands	1.124592	3.426888	0.00	1.440422	3.427086	0.00	0.315830	0.000198	0.00
9	Eastern	2.270467	3.426888	0.00	2.028402	3.427086	0.00	-0.242065	0.000198	0.00
10	South Wales	-1.762889	3.426888	0.00	-2.498402	3.427086	0.00	-0.735513	0.000198	0.00
11	South East	4.687721	3.426888	0.00	4.399951	3.427086	0.00	-0.287770	0.000198	0.00
12	London	8.118524	3.426888	0.00	7.855847	3.427086	0.00	-0.262677	0.000198	0.00
13	Southern	6.116885	3.426888	0.00	5.798754	3.427086	0.00	-0.318131	0.000198	0.00
14	South Western	4.353323	3.426888	0.00	3.967091	3.427086	0.00	-0.386232	0.000198	0.00

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

The AGIC is the Avoided GSP (grid supply point) Infrastructure Credit, which is indexed by average May to October RPI each year.

The phased residual is the amount of the HH residual due as a payment to the embedded generator each year. This will reduce to zero by 2020/21.



# E

## Appendix E: Locational demand profiles

## Locational demand profiles

The table below shows the latest locational demand and demand charging base forecast used in the July forecast. Locational nodal demand have not been changed since March tariffs, while zonal demand charging base forecast have been updated.

Gross tariff model peak demand charging base has increased since the March forecast at 50.4GW.

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

**Table 23 Demand profile**

Zone	Zone Name	2020/21 March					2020/21 July				
		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	362	1,459	439	0.76	1,229	362	1,470	441	0.76	1,330
2	Southern Scotland	2,644	3,355	1,210	1.65	698	2,644	3,360	1,229	1.66	870
3	Northern	2,649	2,523	1,036	1.17	515	2,649	2,510	1,041	1.18	470
4	North West	3,169	3,941	1,478	1.93	388	3,169	3,950	1,459	1.94	380
5	Yorkshire	4,388	3,745	1,564	1.75	703	4,388	3,770	1,582	1.77	710
6	N Wales & Mersey	2,394	2,576	1,041	1.22	577	2,394	2,570	1,035	1.23	580
7	East Midlands	5,296	4,561	1,765	2.18	552	5,296	4,590	1,778	2.20	550
8	Midlands	4,410	4,155	1,562	1.98	239	4,410	4,170	1,585	1.99	240
9	Eastern	6,097	6,305	2,078	3.08	656	6,097	6,340	2,089	3.11	610
10	South Wales	1,666	1,784	818	0.84	390	1,666	1,780	803	0.84	380
11	South East	3,813	3,818	1,160	1.91	336	3,813	3,830	1,163	1.92	330
12	London	5,380	4,113	2,242	1.80	133	5,380	4,120	2,232	1.82	120
13	Southern	6,220	5,360	2,026	2.57	402	6,220	5,390	2,043	2.59	390
14	South Western	2,244	2,553	746	1.29	275	2,244	2,550	738	1.30	270
<b>Total</b>		<b>50,731</b>	<b>50,247</b>	<b>19,164</b>	<b>24.13</b>	<b>7,091</b>	<b>50,731</b>	<b>50,400</b>	<b>19,219</b>	<b>24.31</b>	<b>7,230</b>



# F

## Appendix F: Annual Load Factors

## Specific ALFs

The table below lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2020/21. 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 2013/14 to 2017/18. Generators which commissioned after 1 April 2015 will have fewer than three complete years of data so the appropriate Generic ALF listed below is added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2020/21 also use the Generic ALF for their first year of operation.

These ALFs will be finalised in November 2019.

Table 24 Specific Annual Load Factors

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
ABERTHAW	Coal	Actual	Actual	Actual	Actual	Actual	65.5413%	59.0043%	54.2611%	50.8335%	5.0742%	54.6997%
ACHRUACH	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	33.6464%	36.7140%	44.3464%	38.2356%
AFTON	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.8738%	37.2641%
AIKENGALL II	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.5082%	36.8089%
AN SUIDHE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	41.5843%	36.9422%	35.4900%	34.0938%	41.2323%	37.8882%
ARECLEOCH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	33.8296%	29.7298%	36.8612%	19.7246%	35.1728%	32.9108%
BAGLAN BAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.4106%	37.9194%	29.1228%	55.2030%	24.2891%	30.4438%
BARROW	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	54.1080%	47.0231%	47.1791%	44.2584%	47.0417%	47.0813%
BARRY	CCGT_CHP	Actual	Actual	Actual	Partial	Actual	1.2989%	0.4003%	2.1727%	24.3468%	0.5407%	1.3374%
BEAULY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	35.6683%	37.1167%	35.0094%	30.4872%	21.9937%	33.7216%
BEINNEUN	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	30.9623%	25.8214%	31.7476%
BHLARAI DH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.4339%	46.3209%	39.4047%
BLACK LAW	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9648%	26.7881%	26.9035%	23.4623%	21.2137%	25.7180%
BLACKCRAIG WINDFARM	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	36.0208%	37.6465%
BLACKLAW EXTENSION	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	33.4635%	13.1095%	30.4870%	25.6867%
BRIMSDOWN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.7645%	11.1229%	16.4463%	45.0615%	27.6168%	20.9426%
BURBO BANK EXT	Offshore_Wind	Generic	Generic	Actual	Actual	Actual	0.0000%	0.0000%	16.7781%	25.0233%	49.3850%	30.3955%
CARRAIG GHEAL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	45.2760%	48.9277%	45.6254%	40.4211%	45.5371%	45.4795%
CARRINGTON	CCGT_CHP	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	38.7318%	58.0115%	58.8066%	51.8500%
CLUNIE	Hydro	Actual	Actual	Actual	Actual	Actual	45.3256%	43.2488%	47.9711%	32.8297%	32.1699%	40.4681%
CLYDE (NORTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	42.6598%	36.8882%	41.4120%	26.8858%	39.2619%	39.1873%
CLYDE (SOUTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.8941%	29.4115%	39.9615%	34.8751%	39.1634%	37.9775%
CONNAHS QUAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	12.8233%	18.3739%	28.2713%	37.4588%	20.0846%	22.2433%
CONON CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	54.2820%	55.5287%	58.9860%	48.6782%	50.8547%	53.5551%
CORB Y	CCGT_CHP	Actual	Actual	Actual	Generic	Partial	8.0834%	9.6755%	4.5411%	0.0000%	44.6503%	7.4333%
CORRIEGARTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	22.5645%	41.2013%	34.0750%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	32.2316%	30.4210%	33.7040%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	9.7852%	17.5123%	26.4000%	63.0383%	16.4022%	20.1048%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
COTTAM	Coal	Actual	Actual	Actual	Actual	Actual	67.3951%	51.4426%	34.4157%	14.9387%	21.6580%	35.8388%
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.0249%	31.3132%	28.2382%	67.2482%	56.3007%	38.6174%
COUR	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.3247%	55.4273%	44.0704%
COWES	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0956%	0.3135%	0.4912%	0.5319%	0.6942%	0.4456%
CRUACHAN	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	9.6969%	9.0516%	8.8673%	7.1914%	9.6225%	9.1805%
CRYSTAL RIG II	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	50.2549%	47.5958%	48.3836%	40.2679%	52.5802%	48.7447%
CRYSTAL RIG III	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	39.9503%	51.9020%	43.4372%
DAMHEAD CREEK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	77.1783%	67.4641%	64.8983%	68.1119%	63.5108%	66.8248%
DEESIDE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	17.3035%	13.9018%	17.4579%	27.1090%	20.8164%	18.5259%
DERSALLOCH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.7728%	39.8576%	37.3632%
DIDCOT B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.6624%	25.5345%	41.1389%	50.1358%	44.1234%	36.9322%
DIDCOT GTS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0902%	0.2843%	0.4861%	0.0452%	0.6337%	0.2869%
DINORWIG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	15.0898%	15.0650%	14.6353%	15.9596%	14.9467%	15.0338%
DRAX	Coal	Actual	Actual	Actual	Actual	Actual	80.5151%	82.2149%	76.2030%	62.2705%	55.8896%	72.9962%
DUDGEON	Offshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	42.4791%	46.9782%	46.3364%
DUNGENESS B	Nuclear	Actual	Actual	Actual	Actual	Actual	61.0068%	54.6917%	70.7617%	79.3403%	68.2086%	66.6590%
DUNLAW EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.8226%	30.0797%	29.1203%	26.5549%	31.0840%	30.0947%
DUNMAGLASS	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.9713%	75.6936%	51.0414%
EDINBANE WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.4785%	31.2458%	35.5937%	32.5009%	34.5929%	34.2292%
EGGBOROUGH	Coal	Actual	Actual	Actual	Partial	Actual	72.1843%	45.7421%	27.0157%	40.0283%	7.1715%	48.3140%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	28.2628%	25.3585%	28.1507%	16.1775%	13.6081%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.3314%	33.1849%	34.9919%
FALLAGO	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	54.8683%	44.7267%	55.7992%	43.2176%	49.4158%	49.6703%
FARR WINDFARM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	44.7212%	38.5712%	40.9963%	34.1766%	38.3046%	39.2907%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	35.3695%	57.4834%	53.1573%	30.9768%	38.1673%	42.2314%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	63.3619%	72.8484%	57.6978%	63.2006%	76.0793%	66.4703%
FFESTINIOG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	5.4631%	4.3251%	3.4113%	5.6749%	4.2118%	4.6667%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	49.0374%	45.2435%	27.4591%	8.2478%	13.9908%	28.8978%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	59.9142%	59.4092%	65.1349%	49.6402%	52.6415%	57.3216%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	14.7097%	12.3048%	15.4323%	11.3046%	14.5333%	13.8493%
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	32.5600%	38.9709%	36.6634%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	34.9765%	42.4455%	38.6271%
GALLOPER	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	54.7593%	51.2877%
GARRY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	55.9308%	64.3828%	60.2772%	61.0498%	60.0010%	60.4426%
GLANDFORD BRIGG	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	1.5673%	0.5401%	1.8191%	2.7682%	1.8418%	1.7427%
GLEN APP	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	25.1373%	24.8393%	29.4787%
GLENDOE	Hydro	Actual	Actual	Actual	Actual	Actual	36.3802%	32.3494%	34.8532%	23.8605%	24.0105%	30.4044%
GLENMORISTON	Hydro	Actual	Actual	Actual	Actual	Actual	44.4594%	48.7487%	50.6921%	34.6709%	44.3960%	45.8680%
GORDONBUSH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	46.5594%	47.7981%	47.7161%	50.4126%	34.1762%	47.3579%
GRAIN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.3833%	44.0031%	39.7895%	53.8227%	39.7755%	41.7253%
GRANGEMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	55.9047%	62.6168%	59.8274%	51.4558%	58.9786%	58.2369%
GREAT YARMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.7409%	18.6633%	59.8957%	63.5120%	50.1521%	43.5962%
GREATER GABBARD	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	48.3038%	42.1327%	50.2468%	43.1132%	46.4939%	45.9703%
GRIFFIN WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9566%	31.3152%	31.0284%	25.8228%	28.8970%	30.4135%
GUNFLEET SANDS I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	56.6472%	47.0132%	50.4650%	45.7940%	47.3019%	48.2600%
GUNFLEET SANDS II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	52.2361%	44.7211%	49.0521%	43.9893%	46.9928%	46.9220%
GWYNT Y MOR	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	8.0036%	61.6185%	63.1276%	44.8323%	50.4031%	52.2846%
HADYARD HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.9488%	27.7635%	36.6527%	31.4364%	34.0375%	32.4742%
HARESTANES	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	24.1419%	28.6355%	27.8093%	22.5464%	29.0125%	28.4858%
HARTLEPOOL	Nuclear	Actual	Actual	Actual	Actual	Actual	73.7557%	56.2803%	53.8666%	78.0390%	80.6218%	69.3583%
HEYSHAM	Nuclear	Actual	Actual	Actual	Actual	Actual	73.3628%	68.8252%	72.7344%	79.6169%	85.1617%	75.2380%
HINKLEY POINT B	Nuclear	Actual	Actual	Actual	Actual	Actual	68.8664%	70.1411%	67.6412%	71.2265%	83.4643%	70.0780%
HUMBER GATEWAY	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	43.9343%	62.9631%	59.7195%	54.9913%	59.2246%
HUNTERSTON	Nuclear	Actual	Actual	Actual	Actual	Actual	84.7953%	79.1368%	82.1786%	83.2939%	79.8644%	81.7790%
IMMINGHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	37.8219%	56.8316%	69.4686%	71.9550%	64.3175%	63.5392%
INDIAN QUEENS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2321%	0.0876%	0.0723%	0.0847%	0.0740%	0.0821%
KEADBY	CCGT_CHP	Actual	Generic	Partial	Actual	Actual	0.0001%	0.0000%	35.1858%	28.6076%	38.6957%	22.4345%
KEITH HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	36.9858%	37.9681%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
KILBRAUR	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	51.3777%	54.3550%	50.3807%	46.5342%	56.7501%	52.0378%
KILGALLIOCH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	25.2739%	25.3254%	29.6862%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	45.5356%	44.8205%	53.2348%	27.4962%	34.9231%	41.7597%
KILLINGHOLME (POWERGEN)	Gas_Oil	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	0.5443%	0.3624%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	40.8749%	34.8629%	16.5310%	44.5413%	42.3368%	39.3582%
LINCS WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	46.5987%	43.8178%	49.1306%	44.5192%	51.0911%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	33.6286%	49.6644%	39.9829%	64.8597%	66.3067%	51.5023%
LOCHLUICHART	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	27.6728%	20.2103%	29.2663%	31.6897%	34.3322%	31.7627%
LONDON ARRAY	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	51.2703%	64.0880%	66.8682%	53.6245%	50.5515%	56.3276%
LYNEMOUTH	Coal	Generic	Generic	Partial	Generic	Actual	0.0000%	0.0000%	68.0196%	0.0000%	1.0783%	35.5714%
MARCHWOOD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	48.6845%	66.4021%	55.0879%	75.4248%	67.3692%	62.9531%
MARK HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	30.2863%	26.7942%	34.0227%	21.9653%	31.0915%	29.3907%
MEDWAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.5545%	28.0962%	34.1799%	35.1505%	36.7261%	32.4756%
MILLENNIUM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	52.6618%	53.2636%	48.4038%	44.9764%	53.6488%	51.4431%
MINNYGAP	Onshore_Wind	Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	30.9962%	35.9716%
NANT	Hydro	Actual	Actual	Actual	Actual	Actual	35.5883%	36.4040%	37.3788%	30.6350%	34.9026%	35.6317%
ORMONDE	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	49.6561%	42.8711%	47.1986%	41.2188%	37.7162%	43.7628%
PEMBROKE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	60.3928%	67.5346%	64.5596%	77.6478%	70.2866%	67.4603%
PEN Y CYMOEDD	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	26.9446%	36.0948%	33.8329%
PETERBOROUGH	CCGT_CHP	Actual	Actual	Partial	Actual	Actual	1.8311%	1.0929%	4.1032%	1.7914%	0.4349%	1.5718%
PETERHEAD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.8811%	0.4858%	23.3813%	42.2292%	65.7808%	35.8305%
RACE BANK	Offshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	45.3062%	38.1978%	44.3520%
RAMPION	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	40.9885%	46.6974%
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	71.7403%	56.1767%	19.6814%	15.4657%	19.3780%	31.7454%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	46.7562%	55.3209%	51.9700%	50.5096%	42.5599%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	48.0629%	53.4150%	56.0881%	51.5383%	47.3991%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	2.6155%	4.4252%	19.8061%	58.6806%	29.8122%	18.0145%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	7.4695%	5.3701%	7.7906%	15.6538%	13.4736%	9.5779%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	69.0062%	67.9518%	55.6228%	77.4019%	70.1596%	69.0392%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
SANQUHAR	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	35.2098%	37.3761%
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.2781%	25.6956%	27.2136%	41.6815%	55.4606%	31.5303%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	25.0221%	18.9719%	28.6790%	19.8588%	13.6007%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	32.4163%	24.6354%	18.3226%	64.4246%	55.6920%	37.5812%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	49.3517%	46.2286%	53.6184%	46.9715%	54.3071%	49.9805%
SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.7501%	10.2239%	48.9514%	68.9863%	64.2994%	44.6670%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	82.5051%	84.7924%	98.7826%	81.6359%	73.3708%	82.9778%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	14.3471%	15.5941%	13.9439%	8.1782%	12.0303%	13.4404%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	24.3373%	34.4673%	48.6753%	55.3419%	34.6174%	39.2533%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	33.4800%	39.3092%	47.9407%	60.9748%	52.9683%	46.7394%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	37.6216%	56.6148%	69.4422%	65.7791%	52.0701%	58.1547%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	49.6340%	36.1987%	40.2313%	42.0213%
STRONELAIRG	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	37.5366%	38.1517%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	9.4124%	17.2025%	13.1999%	38.0184%	29.1878%	19.8634%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0483%	0.0640%	0.1708%	0.8047%	1.1712%	0.3465%
THANET	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	39.7489%	35.5935%	41.3434%	33.7132%	38.5069%	37.9498%
TODDLBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	39.5374%	33.7211%	35.0823%	31.3435%	38.0158%	35.6064%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	86.4669%	91.4945%	85.7725%	97.9942%	86.4413%	88.1343%
USKMOUTH	Coal	Actual	Partial	Actual	Actual	Actual	38.9899%	46.9428%	25.5184%	24.3304%	0.1000%	29.6129%
WALNEY 4	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	45.2033%	48.1024%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	57.7046%	52.0555%	50.7535%	47.4617%	55.9472%	52.9187%
WALNEY II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	61.9219%	58.2355%	35.7988%	54.9727%	62.8290%	58.3767%
WALNEY III	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	50.1762%	49.7600%
WEST BURTON	Coal	Actual	Actual	Actual	Actual	Actual	68.9176%	61.5364%	32.7325%	10.1071%	11.8199%	35.3629%
WEST BURTON B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	30.3021%	46.8421%	59.3477%	54.2878%	63.2420%	53.4925%
WEST OF DUDDON SANDS	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	40.4810%	40.0506%	48.7540%	48.7691%	55.4034%	50.9755%
WESTERMOST ROUGH	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	26.2900%	54.8014%	58.1061%	63.4740%	58.7938%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	35.1074%	29.8105%	31.8773%	27.2893%	29.6336%	30.4405%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	27.0102%	27.7787%	26.7655%	23.5253%	25.1664%	26.3140%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	
WHITESIDE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.3704%	38.4297%
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	4.4941%	21.5867%	16.1379%	14.4130%	15.5750%	15.3753%
WINDY STANDARD II	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	43.2981%	40.0722%

## Generic ALFs

**Table 25 Generic ALFs**

<b>Technology</b>	<b>Generic ALF</b>
Gas_Oil #	0.2715%
Pumped_Storage	10.6826%
Tidal *	18.9000%
Biomass	26.8847%
Wave *	31.0000%
Onshore_Wind	38.4593%
CCGT_CHP	48.6379%
Hydro	42.4165%
Offshore_Wind	49.5519%
Coal	37.6162%
Nuclear	76.3178%

# Includes OCGTs (Open Cycle Gas Turbine generating plant).

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

These Generic ALFs are calculated in accordance with CUSC 14.15.109. The Biomass ALF for 2017/18 has been copied from the 2015/16 year due to there not being any single majority biomass-fired stations operating since that period.



# G

## Appendix G: Contracted generation changes since the March forecast

The table below shows the TEC changes notified between the March and July forecasts. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

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

**Table 26 Contracted generation changes**

Power Station	MW Change	Node	Generation Zone
Auchencrosh (interconnector CCT)	387	AUCH20	10
Barry Power Station	-235	ABTH20	21
Bolney	-50	BOLN40	26
BP Grangemouth	120	GRMO20	9
Dorenell Windfarm	-43	DORE11	1
East Anglia One	129	BRFO40	18
Fiddlers Ferry	-1987	FIDF20_ENW	15
Glenmoriston (part of the Moriston Cascade)	3	GLEN1Q	3
Great Yarmouth	15	NORM40	18
Heysham Power Station	-12	HEYS40	14
Kemsley	50	KEMS40	24
Kemsley Battery	-50	KEMS40	24
Kings Lynn A	-99	WALP40_EME	17
Liberty Steel Dalzell	-18	WISH10	11
Mossford (part of the Conon Cascade)	0	MOSS1S	1
Norwich	50	NORM40	18
Norwich Battery	-50	NORM40	18
Powersite @ Drakelow	-380	DRAK40	18
Robin Rigg East Offshore Wind Farm	-6	HARK40	12
Spalding Energy Expansion	-300	SPLN40	17
Sundon	50	SUND40	18
Sundon Battery	-50	SUND40	18
Swansea Bay	-320	BAGB20	21
Thorpe Marsh	-1600	THOM41	16
Triton Knoll Offshore Wind Farm	-540	BICF4A	17
West Burton A	-12	WBUR40	16
Willington	-1530	WILE40	18

The contracted generation used in the Transport model will be fixed at the next (November) forecast of 2020/21 tariffs, using the TEC register as of 31 October 2019, as stated by the CUSC 14.15.6.



# H

## Appendix H: Transmission company revenues

## Transmission Owner revenue forecasts

All onshore TOs (NGET, Scottish Power Transmission and SHE Transmission) and offshore TOs will updated us with their latest revenue forecast by October 2019.

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

Notes:

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

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

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

## NGESO TNUoS revenue pass-through items forecasts

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

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

**Table 27 NGESO revenue breakdown**

Term	NGESO TNUoS Other Pass-Through			
	March Forecast	July Forecast	Nov Draft	Jan Final
Embedded Offshore Pass-Through (OFETt)	0.6	0.6		
Network Innovation Competition (NICFt)	31.6	31.6		
Interconnectors Cap&Floor Revenue Adjustment (TIC)	-10.8	-10.8		
ESO Network Innovation Allowance (NIAt)	3.0	3.2		
Offshore Transmission Revenue (OFTOt)	441.8	438.2		
Financial facility (FINt)	6.3	6.3		
NGET revenue pas-through (NGETTOt)	1751.4	1746.7		
SPT revenue pass-through (TSPt)	368.7	366.8		
SHETL revenue pass-through (TSHt)	358.2	356.6		
<b>Total</b>	<b>2950.8</b>	<b>2939.3</b>		

## Onshore TOs (NGET, SPT and SHETL) revenue forecast

The three onshore TOs (National Grid Electricity Transmission, Scottish Power Transmission and Scottish Hydro Electric Transmission) will update NGESO with their 2020/21 revenue forecast by early October 2019, and November Draft tariffs will reflect those updates. For July forecast, financial parameters and a few minor items have been updated.

## 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 2020. The indicative OFTO revenue to be collected via TNUoS for 2020/21 is £438.2m, a decrease of £3.6m from March. Revenues have been adjusted to take into account an updated RPI forecast.

Since year 2018/19, under CMP283, TNUoS charges can be adjusted by an amount (determined by Ofgem) to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime, and redistribution of revenue through IFA's Use of Revenues framework. The latest interconnector revenue forecast shows it reduces 2020/21 TNUoS revenue by around £10.8m.

**Table 28 NGET revenue breakdown**

2020/21 Revenue Description	Regulatory Year	Licence Term	National Grid Electricity Transmission			
			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1571.6	1571.6		
Price Control Financial Model Iteration Adjustment	A2	MODt	-338.3	-338.3		
RPI True Up	A3	TRUt	1.0	1.0		
RPI Forecast	A4	RPIFt	1.3990	1.3940		
<b>Base Revenue [A=(A1+A2+A3)*A4]</b>	<b>A</b>	<b>BRt</b>	<b>1726.8</b>	<b>1720.6</b>		
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.3	26.3		
Temporary Physical Disconnection	B2	TPDt	0.0	0.0		
Inter TSO Compensation	B4	ITCt	0.0	0.0		
<b>Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]</b>	<b>B</b>	<b>PTt</b>	<b>26.3</b>	<b>26.3</b>		
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	15.9	15.9		
<b>Outputs Incentive Revenue [C=C1+C2+C3]</b>	<b>C</b>	<b>OIPt</b>	<b>15.9</b>	<b>15.9</b>		
Network Innovation Allowance	D	NIAt	6.3	7.8		
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0		
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0		
Correction Factor	-K	-K	13.4	13.4		
Financial Facility	FINt		-6.3	-6.3		
<b>Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]</b>	<b>M</b>	<b>TOt</b>	<b>1782.4</b>	<b>1777.7</b>		
Pre-vesting connection charges	S1		30.3	30.3		
Rental Site	S2		0.7	0.7		
<b>TNUoS Collected Revenue [T=M-B5-P]</b>	<b>T</b>		<b>1751.4</b>	<b>1746.7</b>		

**Table 29 SPT revenue breakdown**

2020/21 Revenue Description		Licence Term	Scottish Power Transmission			
			March Forecast	July Forecast	Nov Draft	Jan Final
Regulatory Year						
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	254.2	254.2		
Price Control Financial Model Iteration Adjustment	A2	MODt	-7.4	-7.4		
RPI True Up	A3	TRUt	0.7	0.7		
RPI Forecast	A4	RPIFt	1.4020	1.3940		
<b>Base Revenue [A=(A1+A2+A3)*A4]</b>	<b>A</b>	<b>BRt</b>	<b>347.0</b>	<b>345.0</b>		
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	4.2	4.2		
Temporary Physical Disconnection	B2	TPDt	0.0	0.0		
Inter TSO Compensation	B4	ITCt				
<b>Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]</b>	<b>B</b>	<b>PTt</b>	<b>4.2</b>	<b>4.2</b>		
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	2.6	2.6		
<b>Outputs Incentive Revenue [C=C1+C2+C3]</b>	<b>C</b>	<b>OIPt</b>	<b>2.6</b>	<b>2.6</b>		
Network Innovation Allowance	D	NIAt	1.1	1.1		
Future Environmental Discretionary Rewards	F	EDRt	0.5	0.5		
Transmission Investment for Renewable Generation	G	TIRGt	26.3	26.3		
Correction Factor	-K	-K	0.0	0.0		
Financial Facility	FINt					
<b>Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]</b>	<b>M</b>	<b>TOt</b>	<b>381.6</b>	<b>379.7</b>		
Pre-vesting connection charges	S1		12.9	12.9		
Rental Site	S2					
<b>TNUoS Collected Revenue [T=M-B5-P]</b>	<b>T</b>		<b>368.7</b>	<b>366.8</b>		

**Table 30 SHETL revenue breakdown**

2020/21 Revenue Description	Regulatory Year	Licence Term	SHE Transmission			
			March Forecast	July Forecast	Nov Draft	Jan Final
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	122.5	122.5		
Price Control Financial Model Iteration Adjustment	A2	MODt	79.2	78.5		
RPI True Up	A3	TRUt	-0.9	-0.9		
RPI Forecast	A4	RPIFt	1.3970	1.3940		
<b>Base Revenue [A=(A1+A2+A3)*A4]</b>	<b>A</b>	<b>BRt</b>	<b>280.5</b>	<b>278.9</b>		
Pass-Through Business Rates & Licence fee	B1+B3	RBt+LFt	26.0	26.0		
Temporary Physical Disconnection	B2	TPDt	0.0	0.0		
Inter TSO Compensation	B4	ITCt				
<b>Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]</b>	<b>B</b>	<b>PTt</b>	<b>26.0</b>	<b>26.0</b>		
Reliability Incentive Adjustment, stakeholder Satisfaction Adjustment and SF6 Gas Emission Adjustment	C1+C2+C3	RIt+SSOt+SFIt	1.9	1.9		
<b>Outputs Incentive Revenue [C=C1+C2+C3]</b>	<b>C</b>	<b>OIPt</b>	<b>1.9</b>	<b>1.9</b>		
Network Innovation Allowance	D	NIAt	0.9	0.9		
Future Environmental Discretionary Rewards	F	EDRt	0.0	0.0		
Transmission Investment for Renewable Generation	G	TIRGt	82.3	82.3		
Correction Factor	-K	-K	-30.0	-30.0		
Financial Facility	FINt					
<b>Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]</b>	<b>M</b>	<b>TOt</b>	<b>361.6</b>	<b>360.0</b>		
Pre-vesting connection charges	S1		3.4	3.4		
Rental Site	S2					
<b>TNUoS Collected Revenue [T=M-B5-P]</b>	<b>T</b>		<b>358.2</b>	<b>356.6</b>		

**Table 31 Offshore revenues**

Offshore Transmission Revenue Forecast (£m)	25/07/2019							Notes
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	
Regulatory Year								
Barrow	5.5	5.6	5.7	5.9	6.3	6.4	6.3	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	8.1	7.9	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.7	14.5	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	9.1	8.9	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.5	15.0	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	22.0	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.9	13.4	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	30.1	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	43.3	42.6	Current revenues plus indexation
Thanet		17.5	15.7	19.5	18.6	19.2	19.7	Current revenues plus indexation
Lincs	78.9	25.6	26.7	27.2	28.2	29.2	28.5	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	34.0	29.0	Current revenues plus indexation
West of Duddon Sands			21.3	22.0	22.6	23.6	23.2	Current revenues plus indexation
Humber Gateway		35.3		9.7	12.1	12.5	12.3	Current revenues plus indexation
Westermost Rough			29.3	11.6	13.2	13.6	13.4	Current revenues plus indexation
Burbo Bank					34.3	13.1	13.4	Current revenues plus indexation
Dudgeon						18.7	18.9	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2019/20						66.0	73.0	National Grid Forecast
Forecast to asset transfer to OFTO in 2020/21							45.9	National Grid Forecast
<b>Offshore Transmission Pass-Through (B7)</b>	<b>218.4</b>	<b>248.4</b>	<b>260.8</b>	<b>265.5</b>	<b>317.9</b>	<b>390.6</b>	<b>438.2</b>	

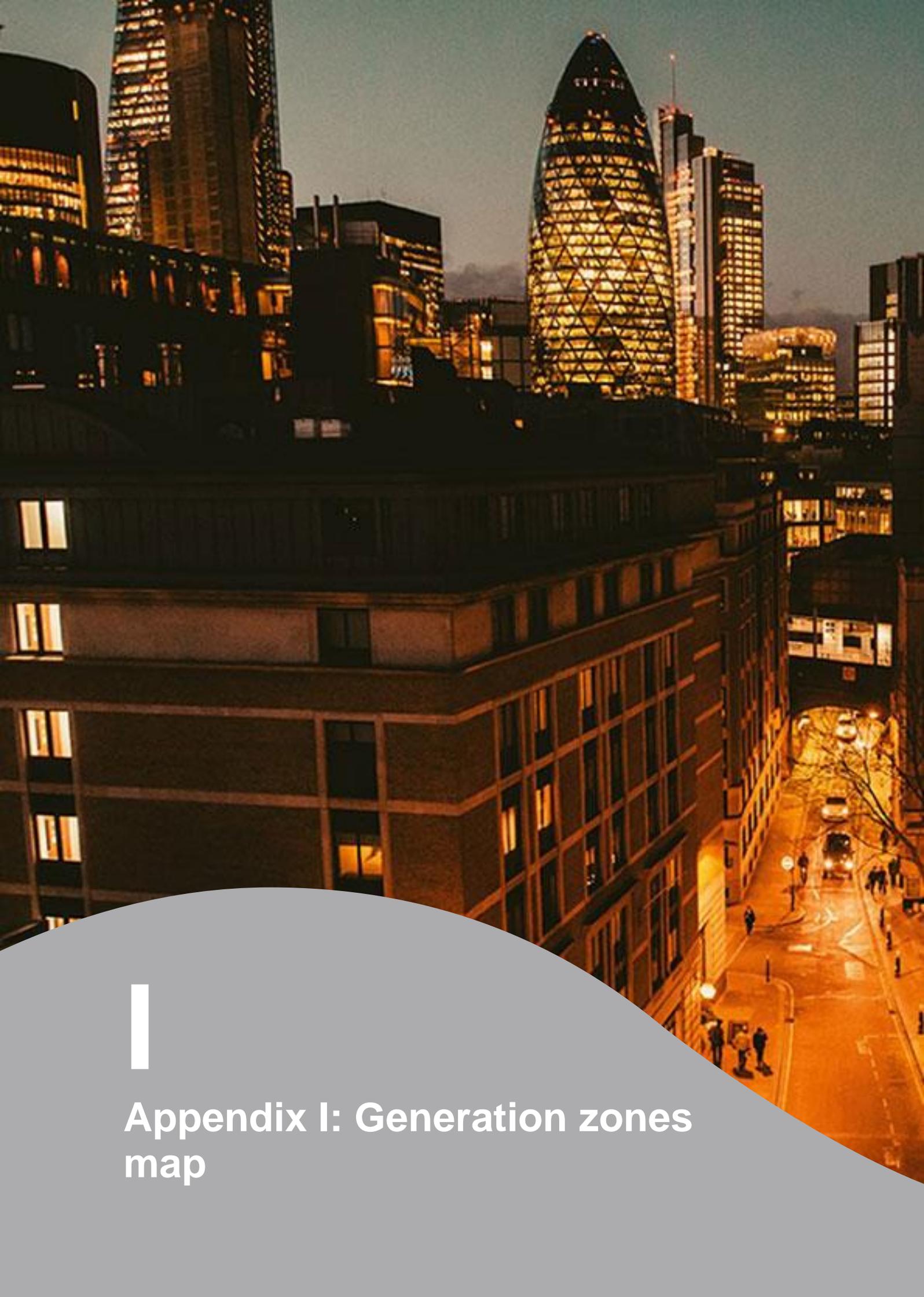
Notes:

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

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

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

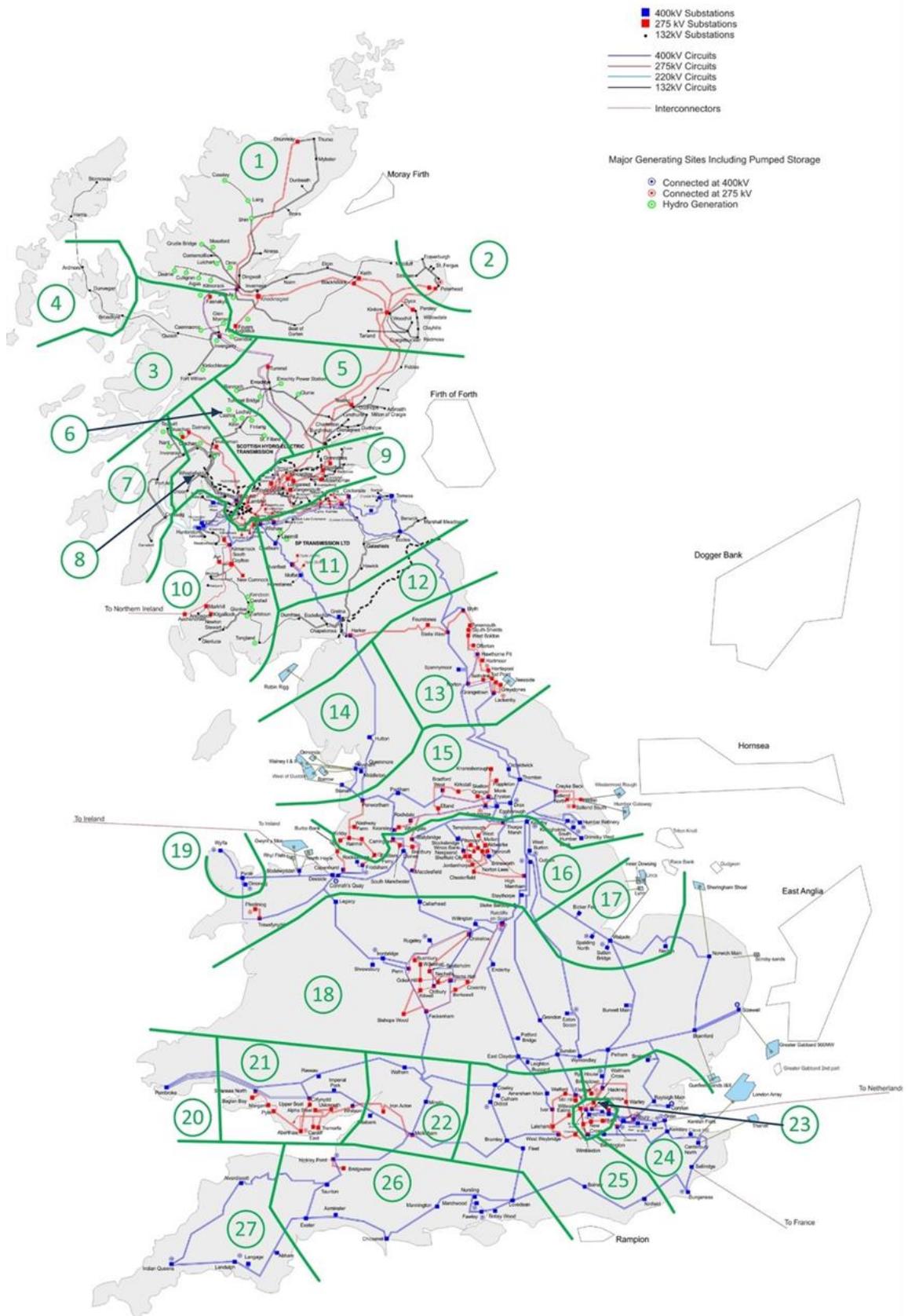
NIC payments are not included as they do not form part of OFTO Maximum Revenue



# I

## Appendix I: Generation zones map

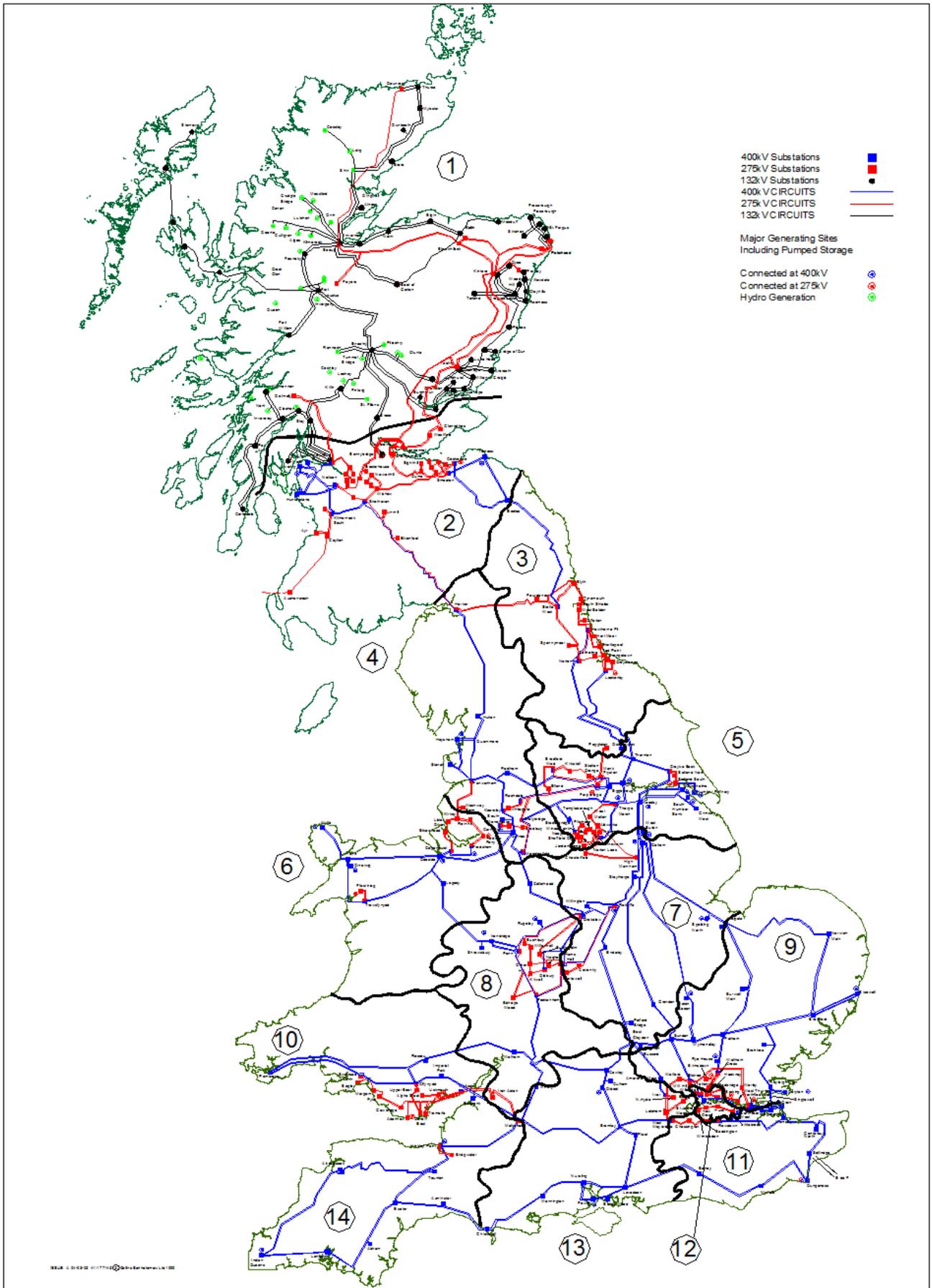
Figure A2: GB Existing Transmission System





# J

## Appendix J: Demand zones map





# K

## Appendix K: Quarterly Changes to TNUoS parameters

## Parameters affecting TNUoS tariffs

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

2020/21 TNUoS Tariff Forecast					
		March 2019	July 2019	Draft tariffs November 2019	January 2020 Final tariffs
<b>Methodology</b>		<i>Open to industry governance</i>			
<b>LOCATIONAL</b>	<b>DNO/DCC Demand Data</b>	Previous year		Week 24 updated	
	<b>Contracted TEC</b>	Latest TEC Register	Latest TEC Register	TEC Register Frozen at 31 October	
	<b>Network Model</b>	Previous year (except local circuit changes)		Latest version based on ETYS	
<b>RESIDUAL</b>	<b>OFTO Revenue</b> <i>(part of allowed revenue)</i>	Forecast	Forecast	Forecast	NG Best View
	<b>Allowed Revenue</b> <i>(non OFTO changes)</i>	Update financial parameters	Update financial parameters	Latest TO Forecasts	From TOs
	<b>Demand Charging Bases</b>	Previous Year	Revised Forecast	<i>By exception</i>	<i>By exception</i>
	<b>Generation Charging Base</b>	NG Best View	NG Best View	NG Best View	NG Final Best View
	<b>Generation ALFs</b>	Previous year		New ALFs published	
	<b>Generation Revenue</b> (G/D split)	Forecast	Generation revenue £m fixed		

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