

Forecast TNUoS

Tariffs for 2019/20

June 2018

nationalgrid



## Forecast TNUoS Tariffs for 2019/20

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

June 2018

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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.nationalgrid.com/tnuos](http://www.nationalgrid.com/tnuos)

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## Executive Summary

**This document contains the latest forecast of the Transmission Network Use of System (TNUoS) tariffs for 2019/20. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.**

The tariffs for 2019/20 were last forecast in April 2018. The next forecast will be the Draft tariffs in November 2018, followed by Final tariffs in January 2019.

### **Total revenues to be recovered**

We forecast the total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges to be £2,879.3m in 2019/20. This is £43.5m more than the April forecast. This change is caused by including a £42.5m forecast of the correction for under recovery in 2017/8, and £1m in additional OFTO revenue. We will be revising these figures throughout the year and they will be confirmed in the Final tariffs report.

### **Generation tariffs**

We are setting generation tariffs to recover £403.5m. This is to ensure that average annual generation tariffs remain below the €2.5/MWh limit. This limit is set by European Commission Regulation (EU) No 838/2010 using the methodology defined in the CUSC. This figure has reduced by £28.3m compared to the April forecast due to a revised forecast of expected generation output. The error margin remains unchanged. The revenue to be recovered from generation, as a total, is now fixed.

The chargeable TEC for 2018/19, we forecast to be 71.9GW. This is an increase of 0.2GW compared to the April forecast. We forecast the average generation tariff to be £5.61/kW. This is a decrease of £0.41/kW

since the April forecast. This is due to the reduction in the total revenue to be recovered from generation.

### **Demand tariffs**

We forecast the revenue to be recovered from demand tariffs to be £2,475.7m in 2019/20. This is an increase of £72m compared to the April forecast, due to the increase in total revenue and a reduction in the amount being recovered from generation.

The chargeable demand used in this forecast is unchanged from our April forecast. We forecast a gross system peak of 51.3GW. Gross HH demand is forecast to be 18GW and NHH demand is forecast to be 25.5TWh. Embedded Export Volume is forecast to be 7.8GW.

We forecast that £111m will be payable through the Embedded Export Tariff (EET). This has only changed slightly compared to April due to the change in the demand locational tariffs which form part of the EET.

The average forecast gross HH demand tariff is £50.75/kW. The average forecast EET is £14.31/kW. The average forecast NHH demand tariff is 6.56p/kWh. Changes in total revenue and the proportion paid by demand mean that the average HH and NHH tariffs have increased since April by £1.39/kW and 0.18p/kWh. Our forecast of the average EET has increased by less than 1p/kW compared



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to April, due to changes in locational demand tariffs.

### **Drivers of changes to the tariff forecast**

The principal drivers for change between our April and June tariff forecasts are:

- Small changes to locational tariffs due to changes in generation patterns;
- An increased overall revenue forecast:
  - We have included a forecast of the correction term from 2017/18 (“K”), and this increases revenue by £42.5m.
  - The latest forecast of OFTO revenue is £1m higher.
- Fixing the total revenue paid by generation. This is £28.3m lower than our previous forecast. This reduces the average generation tariff.
- Overall, it means demand tariffs are forecast to recover £72m more than in the April tariffs, resulting in the average tariff increases.

### **Future forecasts**

In Appendix I we show how we intend to update the various parameters which affect charging in future forecasts.

In this forecast, we have fixed the total £m of revenue to be paid by generation. We have not changed the chargeable demand forecast from the April forecast. However, we may need to adjust the chargeable demand later to ensure we set tariffs to recover the total allowed revenue, as we have further data from the current charging year.

In the November Draft tariffs, we intend to finalise the locational tariffs. The residual tariffs will vary until our Final tariffs in January 2019, as final allowed revenue is not provided to us until late January.

### **Small Generator Discount**

From 2019/20, no discount will be applied to generator tariffs, and no rebate rates will be applied to demand tariffs. This is reflected in these tariffs.

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

### **Changes to the charging methodology which may affect 2019/20 tariffs**

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

#### *Judicial Review of CMP264/265*

On 22 June, the Judicial Review of CMP264/265 was dismissed<sup>1</sup>. Therefore, the changes to the demand tariff structure introduced in April 2018 will remain.

These tariffs are consistent with the methodology implemented under CMP264/265.

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<sup>1</sup> <https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision->

[industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators](https://www.ofgem.gov.uk/publications-and-updates/industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators)

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## Other modifications

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

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

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

CMP301. Seeks to clarify the treatment of project costs associated with HVDC and AC subsea circuits to ensure consistency with onshore circuits in the consideration of expansion factors. This modification has been proposed to the CUSC Panel in June 2018.

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

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

## Next tariff publication

Our next publication of 2019/20 TNUoS tariffs will be the November Draft tariffs.

We will publish our five-year view of TNUoS tariffs up until 2023/24 by the end of August. We have published an open letter<sup>2</sup> about our proposals for that forecast.

The latest tariff forecast timetable can be found on our website.<sup>3</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> See Five-Year Forecast on <https://www.nationalgrid.com/tnuos>

<sup>3</sup> Our forecast publication timetable is available on our website: <http://www.nationalgrid.com/tnuos>

## Demand Tariffs

The tables in this section show demand tariffs for Half-Hourly, Embedded Export and Non-Half-Hour metered demand.

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

**Table 1: Summary of Demand tariffs**

HH Tariffs	2019/20 April	2019/20 June	Change
Average Tariff (£/kW)	49.346251	50.745111	1.398860
Residual (£/kW)	50.298596	51.697066	1.398470
EET	2019/20 April	2019/20 June	Change
Average Tariff (£/kW)	14.301062	14.306876	0.005814
Phased residual (£/kW)	14.650000	14.650000	0.000000
AGIC (£/kW)	3.320000	3.327268	0.007268
Embedded Export Volume (GW)	7.752808	7.752808	0.000000
Total Credit (£m)	110.873388	110.918463	0.045075
NHH Tariffs	2019/20 April	2019/20 June	Change
Average (p/kWh)	6.374706	6.557159	0.182453

**Table 2: Demand tariffs**

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kW)
1	Northern Scotland	21.117249	2.842582	0.000000
2	Southern Scotland	28.797132	3.769871	0.000000
3	Northern	41.292129	5.245346	7.572331
4	North West	48.128953	6.240251	14.409155
5	Yorkshire	48.421349	6.162897	14.701551
6	N Wales & Mersey	49.711398	6.267104	15.991600
7	East Midlands	51.861094	6.794004	18.141296
8	Midlands	53.158467	7.008581	19.438669
9	Eastern	53.903967	7.518310	20.184169
10	South Wales	50.052639	5.904038	16.332841
11	South East	56.648128	8.028688	22.928330
12	London	59.762093	6.338400	26.042296
13	Southern	57.828962	7.651950	24.109165
14	South Western	56.141034	7.836469	22.421236

Residual charge for demand:	£ 51.697066
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## 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 Embedded Export Tariff payment is made to embedded generators which generate over triad periods. Embedded exports, and small embedded generators do not pay generation TNUoS.

Demand tariffs have changed primarily due to the increase in the residual as revenue to recover from demand has gone up. This is caused by an overall increase in revenue, and a reduction in the proportion of revenue to be collected from generation.

The average HH gross tariff is now £50.75/kW; compared to the April forecast this has increased by £1.40/kW. The average NHH tariff is now 6.56p/kWh, an increase of 0.18p/kWh.

The average EET is £14.31/kW which has increased by £0.01/kW. The total revenue to be paid to embedded generators remains almost the same at £111m. This will be recovered through the demand tariffs. More information on the causes of specific zonal fluctuations is detailed in the HH and NHH sections below.

## Gross half hourly demand tariffs

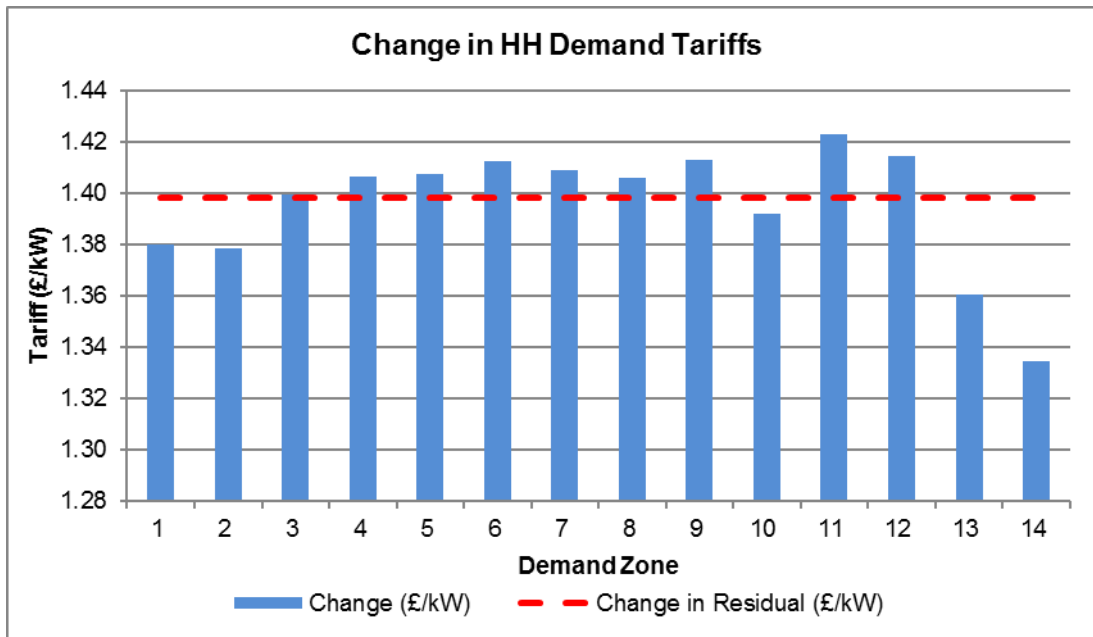
This table and chart show the gross HH demand tariffs for 2019/20 in this June forecast compared to the April forecast.

**Table 3 – Gross HH demand tariffs**

Zone	Zone Name	2019/20 April (£/kW)	2019/20 June (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	19.737006	21.117249	1.380243	1.398470
2	Southern Scotland	27.418724	28.797132	1.378408	1.398470
3	Northern	39.892709	41.292129	1.399420	1.398470
4	North West	46.722382	48.128953	1.406571	1.398470
5	Yorkshire	47.014046	48.421349	1.407303	1.398470
6	N Wales & Mersey	48.298681	49.711398	1.412717	1.398470
7	East Midlands	50.452344	51.861094	1.408750	1.398470
8	Midlands	51.752366	53.158467	1.406101	1.398470
9	Eastern	52.491085	53.903967	1.412882	1.398470
10	South Wales	48.660552	50.052639	1.392087	1.398470
11	South East	55.225293	56.648128	1.422835	1.398470
12	London	58.347780	59.762093	1.414313	1.398470
13	Southern	56.468265	57.828962	1.360697	1.398470
14	South Western	54.806629	56.141034	1.334405	1.398470

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

**Figure 1 - Gross HH demand tariffs**



The average HH gross demand tariff of £50.75/kW has increased by £1.40/kW compared to April, this is almost entirely due to an increase in the residual of £1.40/kW. The level of gross HH chargeable demand has not changed since the last forecast and remains at 18GW.

Generation updates have caused minor changes to system flows, which have caused small zonal variations to tariffs. A small generation increase in south west England has caused a slight reduction in demand tariffs in zones 10, 13 and 14. Zones 11 and 12 have increased marginally due to a very small decrease in generation further east of zones 10, 13 and 14.

The residual element of the tariff has increased by £1.40/kW, this is due to an increase to overall revenue, and a decrease in revenue to be collected from generation.

The locational demand used in the transport model to calculate system flows, and the demand charging base have not been updated for this forecast. The demand used to calculate location tariffs will be updated in the November Draft tariffs when DNOs and directly connected demand customers make available their Week 24 data.

### Embedded export tariff

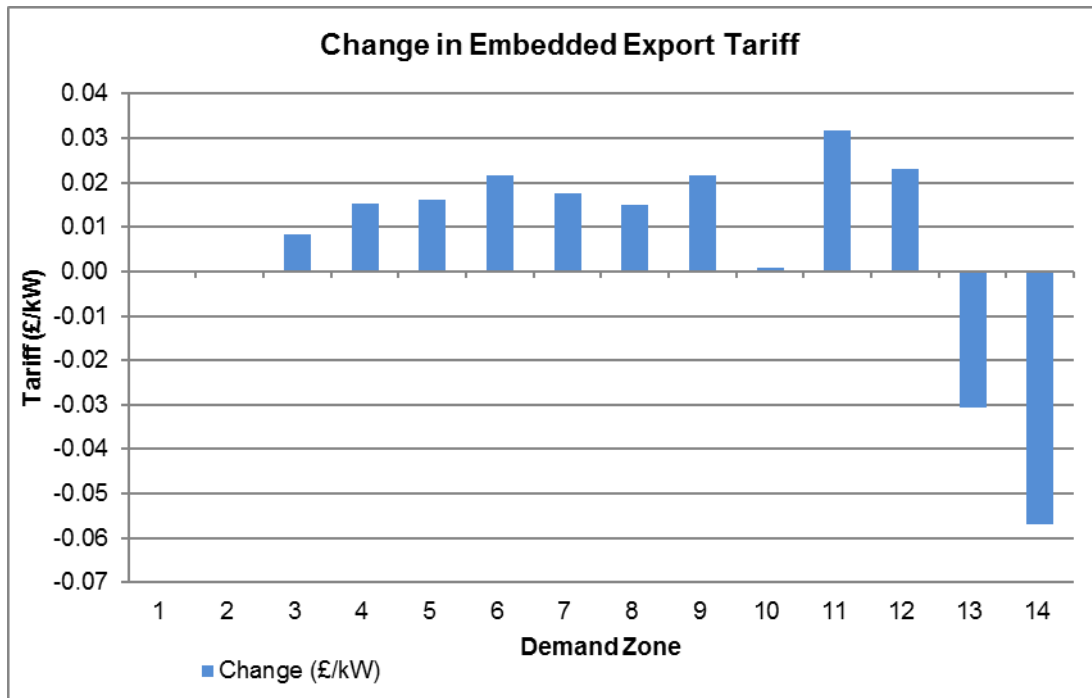
This table and chart show the embedded export tariffs in the June 2019/20 forecast compared to the April forecast.

**Table 4 – Embedded export tariffs**

Zone	Zone Name	2019/20 April (£/kW)	2019/20 June (£/kW)	Change (£/kW)
1	Northern Scotland	0.000000	0.000000	0.000000
2	Southern Scotland	0.000000	0.000000	0.000000
3	Northern	7.564113	7.572331	0.008218
4	North West	14.393786	14.409155	0.015369
5	Yorkshire	14.685451	14.701551	0.016100
6	N Wales & Mersey	15.970085	15.991600	0.021515
7	East Midlands	18.123748	18.141296	0.017548
8	Midlands	19.423770	19.438669	0.014899
9	Eastern	20.162489	20.184169	0.021680
10	South Wales	16.331956	16.332841	0.000885
11	South East	22.896697	22.928330	0.031633
12	London	26.019184	26.042296	0.023112
13	Southern	24.139669	24.109165	-0.030504
14	South Western	22.478033	22.421236	-0.056797

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

**Figure 2 – Embedded Export Tariff**



The amount of metered embedded generation 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.

The average EET has increased by £0.006/kW to £14.31/kW. The EET charging base remains the same at 7.75GW and the forecasted EET revenue is still £111m. The value of the AGIC (avoided GSP infrastructure credit) has been updated with forecasted RPI.

The change in the EET is all due to the change in the demand locational tariffs. Changes in demand locational tariffs are due to the relative position of demand and generation, which has been revised in this forecast, and will be revised again in the November Draft tariffs.

In accordance with the methodology, the value of the EET will steadily reduce until 2020/21. This is primarily a result of the phased reduction to the residual element of the EET, which is described in more detail in the November 2017 five-year forecast.<sup>§</sup> The value of the phased residual element of the tariffs in 2019/20 is £14.65/kW, which has reduced from £29.36/kW in 2018/19. From 2020/21 it will be £0/kW. The result of this is that from 2020/21 we expect the EET to be £0/kW in more demand zones.

See Appendix B for a breakdown of the EET.

## NHH demand tariffs

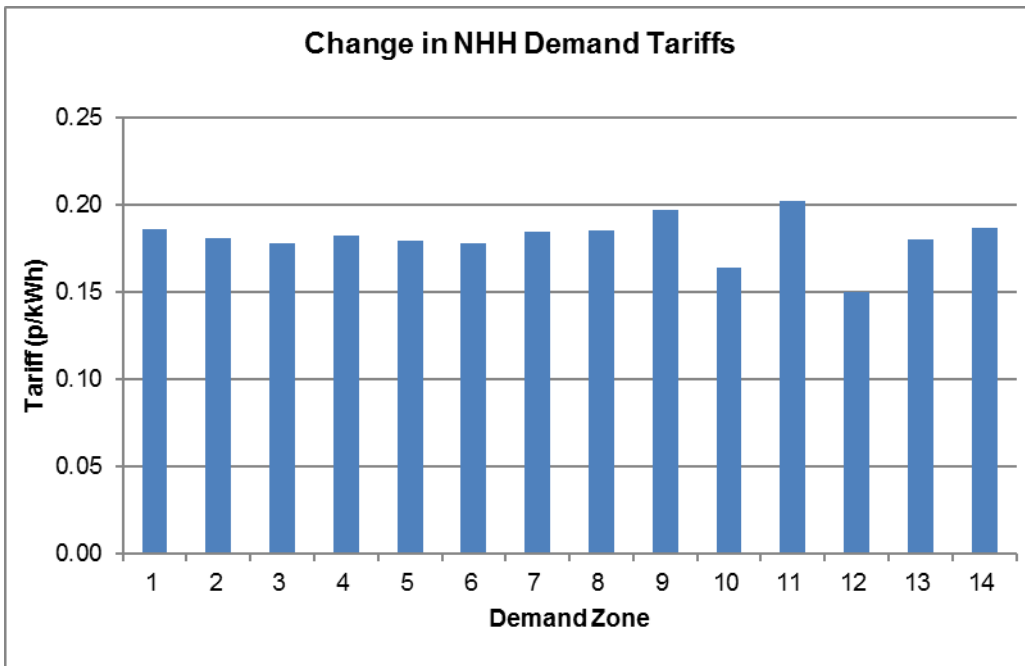
This table and chart show the difference between the NHH demand tariffs forecast in April and this June 2019/20 forecast.

**Table 5 - NHH demand tariff changes**

Zone	Zone Name	2019/20 April (p/kWh)	2019/20 June (p/kWh)	Change (p/kWh)
1	Northern Scotland	2.656788	2.842582	0.185794
2	Southern Scotland	3.589422	3.769871	0.180449
3	Northern	5.067577	5.245346	0.177769
4	North West	6.057879	6.240251	0.182372
5	Yorkshire	5.983781	6.162897	0.179116
6	N Wales & Mersey	6.089003	6.267104	0.178101
7	East Midlands	6.609453	6.794004	0.184551
8	Midlands	6.823196	7.008581	0.185385
9	Eastern	7.321247	7.518310	0.197063
10	South Wales	5.739832	5.904038	0.164206
11	South East	7.827031	8.028688	0.201657
12	London	6.188397	6.338400	0.150003
13	Southern	7.471902	7.651950	0.180048
14	South Western	7.650205	7.836469	0.186264

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

Figure 3 - NHH demand tariff changes



The weighted average NHH tariff is 0.18p/kWh higher than in the April forecast. This is due to the overall increase in revenue to be recovered from demand. As zonal variations to HH tariffs have been minimal, the impact on NHH tariffs is also very small.

## Generation tariffs

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

**Table 6 – Summary of generation tariffs**

Generation Tariffs	2019/20 April	2019/20 June	Change since last forecast
Residual	-3.291240	-3.613060	-0.321820
Average Generation Tariff	6.020832	5.611270	-0.409562

N.B. These generation average tariffs include local tariffs

Average generation tariffs have decreased by £0.41/kW, due to reduced revenue to be recovered from generation. The decrease in the generation residual is £0.32/kW.

## Generation wider tariffs

The following section provides a summary of how the wider generation tariffs have changed between the April forecast and this June forecast. 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 Appendix D. These have been updated for the calculation of 2019/20 tariffs.

The classifications for different technology types are below:

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



**Table 7 - Generation wider tariffs**

Example tariffs for a generator of each technology type:								
Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional Carbon 80% Tariff (£/kW)	Conventional Low Carbon 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	2.633478	17.866048	16.290564	-3.613060	26.345708	29.603820	19.823923
2	East Aberdeenshire	4.856420	10.389876	16.290564	-3.613060	22.587712	25.845825	16.833454
3	Western Highlands	2.066205	18.018719	16.300922	-3.613060	25.908858	29.169042	19.895350
4	Skye and Lochalsh	-4.050899	18.018719	16.185831	-3.613060	19.699681	22.936847	19.780259
5	Eastern Grampian and Tayside	3.028972	15.552842	15.695182	-3.613060	24.414331	27.553368	18.303259
6	Central Grampian	3.703503	14.842849	15.388225	-3.613060	24.275302	27.352947	17.712305
7	Argyll	3.318511	11.768130	25.125685	-3.613060	29.220503	34.245640	26.219877
8	The Trossachs	3.605887	11.768130	13.992947	-3.613060	20.601689	23.400278	15.087139
9	Stirlingshire and Fife	2.379372	8.968928	13.155213	-3.613060	16.465625	19.096667	13.129724
10	South West Scotland	2.432017	9.529142	13.296532	-3.613060	17.079496	19.738803	13.495129
11	Lothian and Borders	3.649624	9.529142	7.437838	-3.613060	13.610148	15.097716	7.636435
12	Solway and Cheviot	1.965527	5.394191	7.505010	-3.613060	8.671828	10.172830	6.049626
13	North East England	3.885956	3.015150	3.943079	-3.613060	5.839479	6.628095	1.536079
14	North Lancashire and The Lakes	1.590933	3.015150	2.657327	-3.613060	2.515855	3.047320	0.250327
15	South Lancashire, Yorkshire and Humber	4.476969	0.783197	0.117564	-3.613060	1.584518	1.608031	-3.182217
16	North Midlands and North Wales	3.942682	-0.830490		-3.613060	-0.334770	-0.334770	-3.945256
17	South Lincolnshire and North Norfolk	2.119470	-0.474296		-3.613060	-1.873027	-1.873027	-3.802778
18	Mid Wales and The Midlands	1.208746	-0.242530		-3.613060	-2.598338	-2.598338	-3.710072
19	Anglesey and Snowdon	4.440111	-0.650476		-3.613060	0.306670	0.306670	-3.873250
20	Pembrokeshire	9.187142	-4.517101		-3.613060	1.960401	1.960401	-5.419900
21	South Wales & Gloucester	6.185924	-4.490373		-3.613060	-1.019434	-1.019434	-5.409209
22	Cotswold	3.040964	2.258661	-6.725791	-3.613060	-4.145800	-5.490958	-9.435387
23	Central London	-5.765060	2.258661	-6.613056	-3.613060	-12.861636	-14.184247	-9.322652
24	Essex and Kent	-4.089630	2.258661		-3.613060	-5.895761	-5.895761	-2.709596
25	Oxfordshire, Surrey and Sussex	-1.567781	-2.951120		-3.613060	-7.541737	-7.541737	-4.793508
26	Somerset and Wessex	-1.407731	-4.113898		-3.613060	-8.311909	-8.311909	-5.258619
27	West Devon and Cornwall	0.103405	-5.677704		-3.613060	-8.051818	-8.051818	-5.884142

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 Appendix D for specific ALFs.

## Changes since the last generation tariffs forecast

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

### Generation wider zonal tariffs

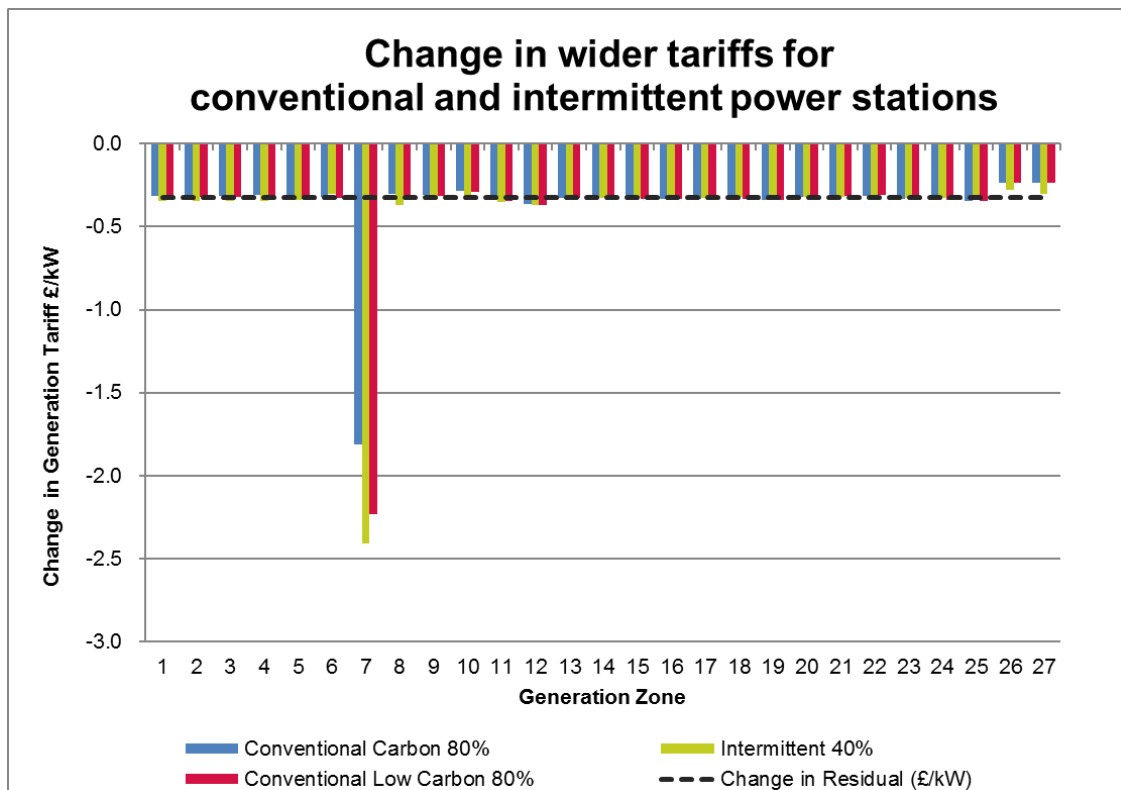
This table and chart show the changes in wider generation TNUoS tariffs between April and this June 2019/20 forecast.

**Table 8 – Generation tariff changes**

The table and graph below show the change in the example Conventional Carbon, Conventional Low Carbon and Intermittent tariffs. The Conventional tariffs use a load factor of 80%, and the Intermittent 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)
		2019/20 April (£/kW)	2019/20 June (£/kW)	Change (£/kW)	2019/20 April (£/kW)	2019/20 June (£/kW)	Change (£/kW)	2019/20 April (£/kW)	2019/20 June (£/kW)	Change (£/kW)	
1	North Scotland	26.657823	26.345708	-0.312115	29.926952	29.603820	-0.323132	20.168315	19.823923	-0.344392	-0.321820
2	East Aberdeenshire	22.894642	22.587712	-0.306930	26.163771	25.845825	-0.317946	17.175399	16.833454	-0.341944	-0.321820
3	Western Highlands	26.220525	25.908858	-0.311667	29.491710	29.169042	-0.322668	20.239207	19.895350	-0.343857	-0.321820
4	Skye and Lochalsh	20.010278	19.699681	-0.310597	23.258369	22.936847	-0.321522	20.123737	19.780259	-0.343478	-0.321820
5	Eastern Grampian and Tayside	24.734248	24.414331	-0.319917	27.883823	27.553368	-0.330455	18.641038	18.303259	-0.337779	-0.321820
6	Central Grampian	24.594901	24.275302	-0.319599	27.679659	27.352947	-0.326712	18.017112	17.712305	-0.304808	-0.321820
7	Argyll	31.033503	29.220503	-1.813000	36.480863	34.245640	-2.235223	28.629747	26.219877	-2.409870	-0.321820
8	The Trossachs	20.906191	20.601689	-0.304503	23.718589	23.400278	-0.318311	15.454935	15.087139	-0.367796	-0.321820
9	Stirlingshire and Fife	16.773731	16.465625	-0.308106	19.411293	19.096667	-0.314626	13.461079	13.129724	-0.331354	-0.321820
10	South West Scotlands	17.365251	17.079496	-0.285755	20.031467	19.738803	-0.292664	13.821000	13.495129	-0.325871	-0.321820
11	Lothian and Borders	13.941138	13.610148	-0.330990	15.440879	15.097716	-0.343163	7.988625	7.636435	-0.352190	-0.321820
12	Solway and Cheviot	9.034564	8.671828	-0.362737	10.545061	10.172830	-0.372231	6.419504	6.049626	-0.369877	-0.321820
13	North East England	6.163235	5.839479	-0.323756	6.952721	6.628095	-0.324626	1.859988	1.536079	-0.323909	-0.321820
14	North Lancashire and The Lakes	2.842774	2.515855	-0.326919	3.376089	3.047320	-0.328769	0.579134	0.250327	-0.328807	-0.321820
15	South Lancashire, Yorkshire and Humber	1.914359	1.584518	-0.329841	1.937901	1.608031	-0.329871	-2.859008	-3.182217	-0.324209	-0.321820
16	North Midlands and North Wales	-0.002136	-0.334770	-0.332634	-0.002136	-0.334770	-0.332634	-3.619785	-3.945256	-0.325471	-0.321820
17	South Lincolnshire and North Norfolk	-1.540292	-1.873027	-0.332735	-1.540292	-1.873027	-0.332735	-3.477826	-3.802778	-0.324953	-0.321820
18	Mid Wales and The Midlands	-2.267717	-2.598338	-0.330621	-2.267717	-2.598338	-0.330621	-3.387540	-3.710072	-0.322532	-0.321820
19	Anglesey and Snowdon	0.642934	0.306670	-0.336264	0.642934	0.306670	-0.336264	-3.545538	-3.873250	-0.327712	-0.321820
20	Pembrokeshire	2.278025	1.960401	-0.317624	2.278025	1.960401	-0.317624	-5.098194	-5.419900	-0.321706	-0.321820
21	South Wales & Gloucester	-0.704660	-1.019434	-0.314775	-0.704660	-1.019434	-0.314775	-5.088058	-5.409209	-0.321151	-0.321820
22	Cotswold	-3.833335	-4.145800	-0.312465	-5.181489	-5.490958	-0.309470	-9.123678	-9.435387	-0.311709	-0.321820
23	Central London	-12.526723	-12.861636	-0.334913	-13.849814	-14.184247	-0.334434	-8.998362	-9.322652	-0.324290	-0.321820
24	Essex and Kent	-5.566879	-5.895761	-0.338883	-5.566879	-5.895761	-0.338883	-2.382909	-2.709596	-0.326687	-0.321820
25	Oxfordshire, Surrey and Sussex	-7.199667	-7.541737	-0.342070	-7.199667	-7.541737	-0.342070	-4.484783	-4.793508	-0.308725	-0.321820
26	Somerset and Wessex	-8.075181	-8.311909	-0.236728	-8.075181	-8.311909	-0.236728	-4.979356	-5.258619	-0.279264	-0.321820
27	West Devon and Cornwall	-7.818249	-8.051818	-0.233569	-7.818249	-8.051818	-0.233569	-5.581055	-5.884142	-0.303086	-0.321820

**Figure 4 - Variation in generation zonal tariffs**



In general the average generation tariff has reduced in line with the reduction in the residual, which is caused by the reduction in revenue to be collected from generation in the fixing of the G/D split.

Tariffs in zone 7 have reduced due a reduction in intermittent generation in that zone, which significantly alters system flows in that area.

Tariffs in zones 26 and 27 have decreased to a lesser extent to other zones due to increases in generation in south west England.

## Onshore local tariffs for generation

### 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 Average May to October RPI, and have been updated from the April forecast to reflect revised RPI forecast for the period May 2018 to October 2018.

**Table 9 - Local substation tariffs**

2019/20		Local Substation Tariff (£/kW)		
Substation Rating	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.197964	0.113248	0.081598
<1320 MW	Redundancy	0.436098	0.269817	0.196232
>=1320 MW	No redundancy	0	0.355083	0.256797
>=1320 MW	Redundancy	0	0.582955	0.425509

### Onshore local circuit tariffs

Where a transmission-connected generator is not directly connected to the Main Interconnected Transmission System (MITS), the onshore local circuit tariffs reflect the cost and flows on circuits between its connection and the MITS. Local circuit tariffs can change as a result of system flows and RPI. If you require further information around a particular local circuit tariff please feel free to contact us.

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

**Table 10 - Onshore local circuit tariffs**

In general system flow changes have been minimal, so the majority of changes to local circuit tariffs have been very small. They have reduced in general due to a small decrease in the expansion constant caused by RPI.

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

All other local circuit tariffs remain relatively stable.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.232856	Dunlaw Extension	1.479750	Lochay	0.360820	Millennium South	0.928492
Aigas	0.644872	Dunhill	1.412272	Luichart	0.565474	Aberdeen Bay	2.570844
An Suidhe	-0.941070	Dumnaglass	1.830606	Mark Hill	0.863311	Killingholme	0.700742
Arecleoch	2.047871	Edinbane	6.748067	Marchwood	0.376314	Middleton	0.109785
Baglan Bay	0.750115	Ewe Hill	1.354956	Millennium Wind	1.800785		
Beinneun Wind Farm	1.480947	Fallago	0.199323	Moffat	0.169407		
Bhlaraidh Wind Farm	0.648822	Farr	3.515507	Mossford	0.441921		
Black Hill	1.531255	Fernoch	4.337104	Nant	-1.211288		
BlackCraig Wind Farm	6.206946	Ffestiniog	0.249457	Necton	-0.362164		
Black Law	1.722917	Finlarig	0.315718	Rhigos	0.100370		
BlackLaw Extension	3.653668	Foyers	0.742448	Rocksavage	0.017456		
Carrington	-0.032834	Galawhistle	1.458315	Saltend	0.336210		
Clyde (North)	0.108132	Glendoe	1.813672	South Humber Bank	0.934230		
Clyde (South)	0.125049	Glenglass	2.938353	Spalding	0.277642		
Corriearth	3.108511	Gordonbush	0.196905	Strathbrora	0.069949		
Corriemoillie	1.640460	Griffin Wind	9.566769	Stronelairg	1.417537		
Coryton	0.051513	Hadyard Hill	2.729153	Strathy Wind	2.028917		
Cruachan	1.865376	Harestanes	2.474147	Wester Dod	0.368855		
Crystal Rig	0.033342	Hartlepool	0.592021	Whitelee	0.104644		
Culligran	1.708927	Hedon	0.178419	Whitelee Extension	0.290910		
Deanie	2.807523	Invergarry	1.399007	Gills Bay	2.483116		
Dersaloch	2.375095	Kilgallioch	1.037718	Kype Muir	1.462492		
Didcot	0.515265	Kilmorack	0.194729	Middle Muir	1.954443		
Dinorwig	2.365700	Langage	0.648563	Dorenell	2.069263		

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

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

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

## Offshore local tariffs for generation

### Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) reflect the cost of offshore networks connecting offshore generation. They are calculated at the beginning of price review or on transfer to the offshore transmission owner (OFTO). The tariffs are subsequently indexed by average May to October RPI each year. Offshore local generation tariffs associated with projects due to transfer in 2019/20 will be confirmed once asset transfer has taken place.

**Table 12 - Offshore Local Tariffs 2019/20**

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.975072	41.725570	1.036103
Burbo Bank	<i>Tariff will be published in November 2018</i>		
Greater Gabbard	14.952323	34.358966	0.000000
Gunfleet	17.259781	15.845830	2.961677
Gwynt Y Mor	18.209536	17.938643	0.000000
Humber Gateway	14.490628	32.695686	0.000000
Lincs	14.904088	58.352912	0.000000
London Array	10.145604	34.555363	0.000000
Ormonde	24.654641	45.929286	0.366018
Robin Rigg East	-0.456078	30.211238	9.363853
Robin Rigg West	-0.456078	30.211238	9.363853
Sheringham Shoal	23.820656	27.936049	0.607248
Thanet	18.140295	33.801853	0.813730
Walney 1	21.278124	42.375328	0.000000
Walney 2	21.123374	42.748657	0.000000
West of Duddon Sands	8.210647	40.514454	0.000000
Westermost Rough	17.288863	29.245358	0.000000

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## Background to TNUoS charging

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

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

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

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

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

## Generation charging principles

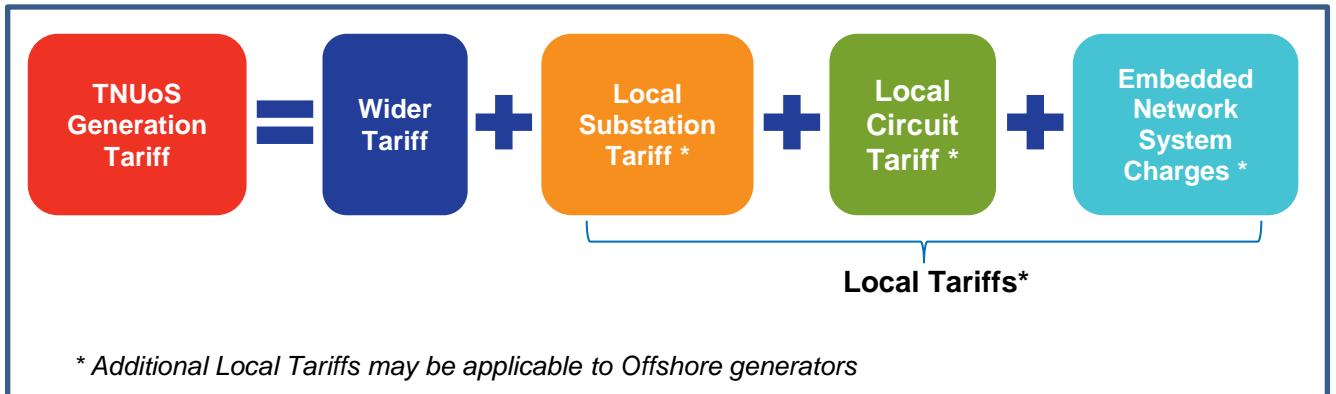
Generators pay TNUoS (Transmission Network Use of System) tariffs to allow National Grid as System Operator to recover the capital costs of building and maintaining the transmission network on behalf of the transmission asset owners (TOs).

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

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



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



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

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

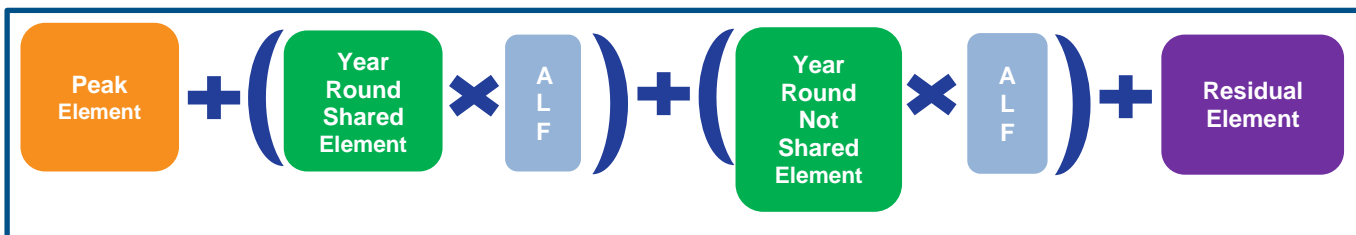
### The Wider tariff

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

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

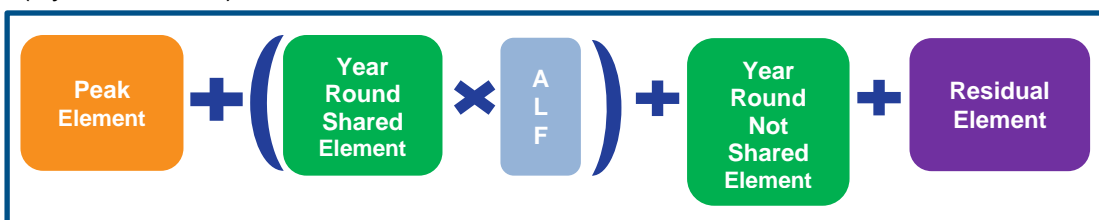
#### Conventional Carbon Generators

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



#### Conventional Low Carbon Generators

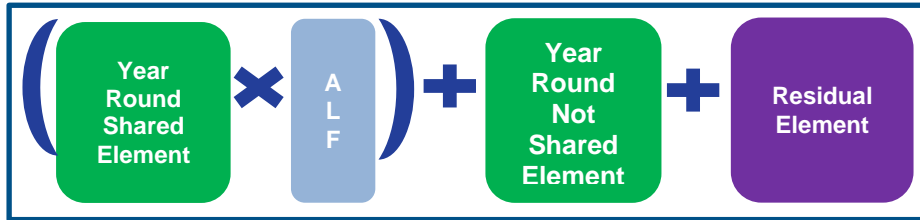
(Hydro, Nuclear)



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## Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

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

### Local substation tariffs

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

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

### Local circuit tariffs

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

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## Embedded network system charges

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

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

[Click here to find out more about DNO regions.](#)

## Offshore local tariffs

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

## Billing

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

The calculation for TNUoS generator liability is as follows:

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

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

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

## Generators with negative TNUoS tariffs

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

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

For more details, please see CUSC 14.18.13–17.

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\*\* For more information about connections, please visit our website:

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

†† These specific charges include any onshore local circuit and substation charges.

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## Demand charging principles

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

### HH gross demand tariffs

HH gross demand tariffs are charged to customers on their metered output during the triads. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year. They can occur on any day at any time, but each peak must be separated by at least ten full days. The final triads are usually confirmed at the end of March once final Elexon data is available, via the NGET website.<sup>##</sup> The tariff is charged on a £/kW basis. On triads, HH customers are charged the HH gross demand tariff against their gross demand volumes.

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

### Embedded export tariffs

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

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

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

Please note that if a supplier's forecast of embedded export volumes across their whole portfolio exceed the volume of HH gross demand in that zone, then they will be billed zero (instead of being paid on a monthly basis for their embedded export volumes).

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.

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<sup>##</sup> <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Triad-Data/>

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

## **NHH demand tariffs**

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

Suppliers are billed against these forecast volumes, and a reconciliation of the amounts paid against their actual metered output is performed once the final metering data is available from Elexon up to 16 months after the financial year in question.

## Updates to revenue & the charging model since the last forecast

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

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

### Changes affecting the locational element of tariffs

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

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

### Table 13 – Contracted and modelled TEC

Contracted TEC is the volume of TEC with connection agreements for the 2019/20 period, which can be found on the TEC register.<sup>§§</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 2019/20 and liable to pay generation TNUoS charges. Chargeable TEC volumes are always based on National Grid's best view of the likely volume of generation TEC connected to the system in the relevant charging year.

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

(GW)	2018/19	2019/20 November Forecast	2019/20 April Forecast	2019/20 June Forecast
Contracted TEC	79.0	85.5	85.9	83.9
Modelled Best View TEC	79.0	77.7	77.5	77.7
Chargeable TEC	71.9	73.8	71.7	71.9

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



## Adjustments for interconnectors

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

**Table 14 – Interconnectors**

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

Interconnector	Site	Interconnected System	Generation Zone	Transport Model (Generation MW) Peak	Transport Model (Generation MW) Year Round	Charging Base (Generation MW)
IFA Interconnector	Sellindge 400kV	France	24	0	2000	0
ElecLink	Sellindge 400kV	France	24	0	1000	0
BritNed	Grain 400kV	Netherlands	24	0	1200	0
Belgium Interconnector (Nemo)	Richborough 400kV	Belgium	24	0	1000	0
East - West	Connah's Quay 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	80	0

## RPI

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

### Expansion Constant

The expansion constant has decreased from 14.55396624 in 2018/19 to a forecast of 14.552251 in the June tariffs. This reflects our latest view of the RPI. To be consistent with tariffs, we have begun to round this to six decimal places.

### Local substation and offshore substation tariffs

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

## Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Compared to the April forecast, tariffs have now been calculated to recover £2,879.3m of revenue. This is an increase of £43.5m from the April forecast of £2835.8m, mainly due to the correction item “K” becoming available (indicative figure only, and is subject to further changes).

Under the relevant STC procedure, TOs will update us with their forecasts on allowed revenues by early October. These figures will be reflected in November draft tariffs.

**Table 15 – Allowed revenues**

£m Nominal Value	2018/19 TNUoS Revenue	2019/20 TNUoS Revenue				
	2018/19 (fixed forecast)	Initial Forecast	April Forecast	June Forecast	Nov Draft	Jan 2019 Final
<b>National Grid</b>						
<i>Price controlled revenue</i>	1,653.9	1768.5	1728.1	1,770.6		
<i>Less income from connections</i>	44.0	41.9	44.0	44.0		
<b>Income from TNUoS</b>	<b>1,609.9</b>	<b>1,726.6</b>	<b>1,684.1</b>	<b>1,726.6</b>		
<b>Scottish Power Transmission</b>						
<i>Price controlled revenue</i>	364.8	404.5	404.5	404.5		
<i>Less income from connections</i>	14.9	14.5	14.5	14.5		
<b>Income from TNUoS</b>	<b>350.0</b>	<b>390.0</b>	<b>390.0</b>	<b>390.0</b>		
<b>SHE Transmission</b>						
<i>Price controlled revenue</i>	369.8	352.9	352.9	352.9		
<i>Less income from connections</i>	3.4	3.5	3.5	3.5		
<b>Income from TNUoS</b>	<b>366.4</b>	<b>349.4</b>	<b>349.4</b>	<b>349.4</b>		
<b>Offshore</b>	318.1	466.7	386.5	387.4		
<b>Network Innovation Competition</b>	32.7	42.5	32.7	32.7		
<b>EDR</b>						
<b>Interconnectors (Cap &amp; Floor)</b>	(6.8)	(6.8)	(6.8)	(6.8)		
<b>Total to Collect from TNUoS</b>	<b>2,670.3</b>	<b>2,968.4</b>	<b>2,835.8</b>	<b>2,879.3</b>		

## Generation / Demand (G/D) Split

The G/D split has changed since the April tariff forecast. The proportion of revenue to be recovered from generation has decreased by 1.2% to 14% 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 Use of System charging methodology, the exchange rate for 2019/20 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2018. The value published is €1.124927/£, which has been slightly corrected from €1.13 in the April forecast.

### Generation Output

The forecast output of generation has reduced to 229.8TWh from 247TWh. This figure has been updated using the latest Future Energy Scenario data. The next FES publication will be available in July 2018.

### Error Margin

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

**Table 16 – Generation and demand revenue proportions**

		2019/20 April	2019/20 June
CAPEC	Limit on generation tariff (€/MWh)	2.50	2.50
y	Error Margin	21.0%	21.0%
ER	Exchange Rate (€/£)	1.13	1.12
MAR	Total Revenue (£m)	2,835.8	2,879.3
GO	Generation Output (TWh)	247.0	229.8
G	% of revenue from generation	15.2%	14.0%
D	% of revenue from demand	84.8%	86.0%
G.MAR	Revenue recovered from generation (£m)	431.8	403.5
D.MAR	Revenue recovered from demand (£m)	2404.0	2475.7

**The total revenue paid by generation, £403.5m, is now fixed for 2019/20 TNUoS tariffs.**

## Charging bases for 2019/20

### Generation

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

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

### Demand

Our forecasts of demand and embedded generation have not been updated since the April tariff forecast. We currently do not intend to update these forecasts again, but we reserve the right to do so before the publication of Final 2019/20 tariffs if we believe it necessary to ensure more accurate revenue recovery.

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 2018)
- Weather patterns
- Future demand shifts
- Expected levels of renewable generation.

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

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

**Table 17 – Charging bases**

Charging Bases	2019/20 April	2019/20 June
Generation (GW)	71.7	71.9
NHH Demand (4pm-7pm TWh)	25.5	25.5
<b>Net Charging</b>		
Total Average Net Triad (GW)	43.6	43.6
HH Demand Average Net Triad (GW)	10.3	10.3
<b>Gross charging</b>		
Total Average Gross Triad (GW)	51.3	51.3
HH Demand Average Gross Triad (GW)	18.0	18.0
Embedded Generation Export (GW)	7.8	7.8

## Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast we have used the final version of the 2018/19 ALFs, based upon data from 2012/13 to 2016/17 available from the National Grid website.<sup>\*\*\*</sup> The ALFs for 2019/20 will be calculated later in this year.

## Generation and Demand Residuals

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

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

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

Where

- $R_G$  is the generation residual tariff (£/kW)

<sup>\*\*\*</sup> <https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf>

- G is the proportion of TNUoS revenue recovered from generation
- R is the total TNUoS revenue to be recovered (£m)
- Z<sub>G</sub> is the TNUoS revenue recovered from generation locational zonal tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L<sub>C</sub> is the TNUoS revenue recovered from onshore local circuit tariffs (£m)
- L<sub>S</sub> is the TNUoS revenue recovered from onshore local substation tariffs (£m)
- B<sub>G</sub> is the generator charging base (GW)

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

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

Where:

- R<sub>D</sub> 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<sub>D</sub> 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<sub>D</sub> is the demand charging base (Half-Hour equivalent GW)

**Z<sub>G</sub>, Z<sub>D</sub>, L<sub>C</sub>, and EE** are determined by the locational elements of tariffs, and for EE the value of the AGIC and phased residual.

**Table 18 - Residual calculation**

	Component	2019/20 April	2019/20 June
<b>G</b>	Proportion of revenue recovered from generation (%)	15.2%	14.0%
<b>D</b>	Proportion of revenue recovered from demand (%)	84.8%	86.0%
<b>R</b>	Total TNUoS revenue (£m)	2,836	2,879
<b>Generation Residual</b>			
<b>R<sub>G</sub></b>	Generator residual tariff (£/kW)	-3.29	-3.61
<b>Z<sub>G</sub></b>	Revenue recovered from the locational element of generator tariffs (£m)	330.7	329.1
<b>O</b>	Revenue recovered from offshore local tariffs (£m)	298.7	296.0
<b>L<sub>G</sub></b>	Revenue recovered from onshore local substation tariffs (£m)	19.2	19.2
<b>S<sub>G</sub></b>	Revenue recovered from onshore local circuit tariffs (£m)	19.1	19.0
<b>B<sub>G</sub></b>	Generator charging base (GW)	71.7	71.9
<b>Gross Demand Residual</b>			
<b>R<sub>D</sub></b>	Demand residual tariff (£/kW)	50.30	51.70
<b>Z<sub>D</sub></b>	Revenue recovered from the locational element of demand tariffs (£m)	-66.7	-66.7
<b>EE</b>	Amount to be paid to Embedded Exports (£m)	110.9	110.9
<b>B<sub>D</sub></b>	Demand gross charging base	51.3	51.3

## Small Generator Discount

As we have previously highlighted in the April forecast<sup>+++</sup> and the November 2017 five-year forecast<sup>###</sup>, there will be no Small Generator Discount from 1 April 2019. Therefore applicable generators will no longer receive the discount to their TNUoS tariffs. Similarly, there will be no additional charge added to demand tariffs to recover the cost of the scheme.

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

<sup>+++</sup>

[https://www.nationalgrid.com/sites/default/files/documents/Forecast%20TNUoS%20Tariffs%20for%202019-20%20-%20Report\\_0.pdf](https://www.nationalgrid.com/sites/default/files/documents/Forecast%20TNUoS%20Tariffs%20for%202019-20%20-%20Report_0.pdf) p.31.

<sup>###</sup> <https://www.nationalgrid.com/sites/default/files/documents/Forecast%20from%202018-19%20to%202022-23%20%282%29.pdf> p.26.

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## Tools and Supporting Information

### Further information

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

### Charging forums

We will hold a webinar for the April tariffs on Friday 6 July 2018 from 10:30 to 11:30. If you wish to join the webinar, please use this registration link ([Register](#)).<sup>\$\$\$</sup>

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

### Charging models

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

### Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website under 2019/20 forecasts:

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

**Team Email & Phone**

[Charging.enquiries@nationalgrid.com](mailto:Charging.enquiries@nationalgrid.com)

01926 654633

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<sup>\$\$\$</sup> <https://uknationalgrid.webex.com/uknationalgrid/j.php?MTID=mfef4823f38192b1edf7920c1e8819237>

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## Appendices

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

Appendix B: Breakdown of HH and EET locational tariffs

Appendix C: Locational demand profiles

Appendix D: Annual Load Factors

Appendix E: Contracted generation changes since the April forecast

Appendix F: Transmission company revenues

Appendix G: Generation zones map

Appendix H: Demand zones map

Appendix I: Parameters affecting TNUoS Tariffs



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

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2019/20 onwards. All these modifications are subject to whether they are approved by Ofgem and which Work Group Alternative CUSC Modification (WACM) is approved.

More information about current modifications can be found at the following location: <https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code?mods>

### **Judicial Review of CMP264/265**

On 22 June, the Judicial Review of CMP264/265 was dismissed\*\*\*\*. Therefore, the changes to the tariff structure introduced in April 2018 will remain.

These tariffs are consistent with the methodology implemented under CMP264/265.

Similarly tariffs for 2018/19, are consistent with the methodology implemented under CMP264/265 and no change to tariffs “mid-year” is required due to this judgement.

### **Other Modifications**

A summary of the mods already in progress which could affect the 2019/20 TNUoS tariffs and their status are listed below.

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

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\*\*\*\* <https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators>

**Table 19: Summary of CUSC modifications affecting 2019/20 TNUoS Tariffs**

Mod Number	Description	Status	Status in the April Forecast
<b>Modification which may affect tariffs from 1 April 2019 if approved</b>			
251	<u>Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010</u>	Pending Ofgem decision – the final modification report was submitted to Ofgem in October 2016.	Not implemented, as no decision yet published by Ofgem
<b>Modifications being considered by CUSC Workgroups which may affect tariffs from 1 April 2019</b>			
280	<u>Creation of a New Generator TNUoS Demand Tariff Which Removes Liability for TNUoS Demand Residual Charges from Generation and Storage Users</u>	At workgroup	Not implemented, as no decision yet published by Ofgem
301	<u>Clarification on the treatment of project costs associated with HVDC and subsea circuits</u>	Proposed at June CUSC Panel	Not implemented, as no decision yet published by Ofgem.
<b>Modifications being considered by CUSC Workgroups which may affect the tariff setting process, having a consequential impact on how/when tariffs are known</b>			
286	<u>Improving TNUoS Predictability through Increased Notice of the Target Revenue used in the TNUoS Tariff Setting Process</u>	At workgroup	N/A
287	<u>Improving TNUoS Predictability Through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process</u>	At workgroup	N/A
292	<u>Introducing a Section 8 cut-off date for changes to the Charging Methodologies</u>	At workgroup	N/A

## Appendix B: Breakdown of HH and EET locational tariffs

**Table 20 – 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 April forecast to the June forecast.

Zone	2019/20 April		2019/20 June		Changes	
	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	-2.047907	-28.513683	-2.041245	-28.538572	0.006662	-0.024889
2	-2.240275	-20.639597	-2.244736	-20.655199	-0.004460	-0.015602
3	-3.581823	-6.824064	-3.578833	-6.826104	0.002990	-0.002040
4	-1.126515	-2.449699	-1.124121	-2.443992	0.002394	0.005707
5	-2.842328	-0.442222	-2.839206	-0.436511	0.003122	0.005711
6	-2.289935	0.290020	-2.259558	0.273890	0.030377	-0.016130
7	-2.161976	2.315725	-2.158902	2.322930	0.003074	0.007206
8	-1.437143	2.890914	-1.436307	2.897707	0.000837	0.006794
9	1.354743	0.837746	1.359903	0.846998	0.005159	0.009252
10	-6.139131	4.501087	-6.144324	4.499897	-0.005193	-0.001190
11	4.203998	0.722699	4.213772	0.737291	0.009774	0.014591
12	5.650585	2.398599	5.656190	2.408838	0.005605	0.010239
13	1.838026	4.331643	1.816925	4.314972	-0.021101	-0.016671
14	-0.921749	5.429782	-0.955920	5.399888	-0.034171	-0.029893

**Table 21 – Breakdown of EET**

This table shows the breakdown of the components that make up the embedded export tariff.

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 in 2017/18 due as a payment to the embedded generator each year. This will reduce to zero by 2020/21.

Demand Zone		2019/20 April			2019/20 June			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	-30.561590	3.320000	14.65	-30.579817	3.327268	14.65	-0.018227	0.007268	0.00
2	Southern Scotland	-22.879872	3.320000	14.65	-22.899934	3.327268	14.65	-0.020062	0.007268	0.00
3	Northern	-10.405887	3.320000	14.65	-10.404937	3.327268	14.65	0.000950	0.007268	0.00
4	North West	-3.576214	3.320000	14.65	-3.568113	3.327268	14.65	0.008101	0.007268	0.00
5	Yorkshire	-3.284549	3.320000	14.65	-3.275717	3.327268	14.65	0.008833	0.007268	0.00
6	N Wales & Mersey	-1.999915	3.320000	14.65	-1.985668	3.327268	14.65	0.014247	0.007268	0.00
7	East Midlands	0.153748	3.320000	14.65	0.164028	3.327268	14.65	0.010280	0.007268	0.00
8	Midlands	1.453770	3.320000	14.65	1.461401	3.327268	14.65	0.007630	0.007268	0.00
9	Eastern	2.192489	3.320000	14.65	2.206901	3.327268	14.65	0.014412	0.007268	0.00
10	South Wales	-1.638044	3.320000	14.65	-1.644427	3.327268	14.65	-0.006383	0.007268	0.00
11	South East	4.926697	3.320000	14.65	4.951062	3.327268	14.65	0.024365	0.007268	0.00
12	London	8.049184	3.320000	14.65	8.065028	3.327268	14.65	0.015844	0.007268	0.00
13	Southern	6.169669	3.320000	14.65	6.131897	3.327268	14.65	-0.037772	0.007268	0.00
14	South Western	4.508033	3.320000	14.65	4.443968	3.327268	14.65	-0.064065	0.007268	0.00

## Appendix C: Locational demand profiles

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

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

Locational model demand remains the same as the November forecast at 51.9GW. Overall net peak demand remains at 43.5GW.

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

**Table 22 – Demand profiles**

Zone	Zone Name	2019/20 April					2019/20 June				
		Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)	Locational Model Demand (MW)	GROSS Tariff model Peak Demand (MW)	GROSS Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Tariff model Embedded Export (MW)
1	Northern Scotland	499	1,483	428	0.78	958	499	1,483	428	0.78	958
2	Southern Scotland	2,695	3,444	1,126	1.77	678	2,695	3,444	1,126	1.77	678
3	Northern	2,702	2,576	902	1.32	439	2,702	2,576	902	1.32	439
4	North West	3,067	4,037	1,413	2.02	410	3,067	4,037	1,413	2.02	410
5	Yorkshire	4,384	3,818	1,495	1.83	808	4,384	3,818	1,495	1.83	808
6	N Wales & Mersey	2,558	2,628	991	1.30	550	2,558	2,628	991	1.30	550
7	East Midlands	5,376	4,651	1,717	2.24	639	5,376	4,651	1,717	2.24	639
8	Midlands	4,425	4,251	1,389	2.17	335	4,425	4,251	1,389	2.17	335
9	Eastern	6,238	6,447	1,931	3.24	806	6,238	6,447	1,931	3.24	806
10	South Wales	1,674	1,822	779	0.88	510	1,674	1,822	779	0.88	510
11	South East	3,871	3,906	1,060	2.01	411	3,871	3,906	1,060	2.01	411
12	London	5,599	4,187	2,203	1.87	171	5,599	4,187	2,203	1.87	171
13	Southern	6,566	5,476	1,933	2.68	693	6,566	5,476	1,933	2.68	693
14	South Western	2,210	2,597	641	1.40	345	2,210	2,597	641	1.40	345
<b>Total</b>		<b>51,865</b>	<b>51,326</b>	<b>18,007</b>	<b>25.51</b>	<b>7,753</b>	<b>51,865</b>	<b>51,326</b>	<b>18,007</b>	<b>25.51</b>	<b>7,753</b>

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## Appendix D: Annual Load Factors

### ALFs

#### Table 23: Specific Annual Load Factors

The table below lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2019/20. ALFs are used to scale the shared year round element of tariffs for each generator, and the year round not shared for Conventional Carbon generators, so that each has a tariff appropriate to its historical load factor.

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

These were finalised for the five-year forecast tariffs published on 1 December 2017.<sup>†††</sup>

The ALFs will be recalculated in time for the November Draft tariffs using data from 2013/14 to 2017/18.

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<sup>†††</sup> <https://www.nationalgrid.com/sites/default/files/documents/Final%202018-19%20ALFs.pdf>

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012/13	2013/14	2014/15	2015/16	2016/17	2012/13	2013/14	2014/15	2015/16	2016/17	
ABERTHAW	Coal	Actual	Actual	Actual	Actual	Actual	74.0137%	65.5413%	59.0043%	54.2611%	50.8335%	59.6022%
ACHRUACH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.6464%	36.7140%	34.8994%
AN SUIDHE WIND FARM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6380%	41.5843%	36.9422%	35.4900%	34.0938%	35.5087%
ARECLEOCH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.4826%	33.8296%	29.7298%	36.8612%	19.7246%	32.0140%
BAGLAN BAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.5756%	16.4106%	37.9194%	29.1228%	55.2030%	31.5393%
BARKING	CCGT_CHP	Actual	Actual	Partial	Generic	Generic	2.3383%	1.8802%	14.1930%	0.0000%	0.0000%	6.1371%
BARROW OFFSHORE WIND LTD	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	42.8840%	54.1080%	47.0231%	47.1791%	44.2584%	46.1536%
BARRY	CCGT_CHP	Actual	Actual	Actual	Actual	Partial	0.6999%	1.2989%	0.4003%	2.1727%	25.4300%	1.3905%
BEAULY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	25.4532%	35.6683%	37.1167%	35.0094%	30.4872%	33.7216%
BEINNEUN	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	30.9622%	33.2125%
BHLARAI DH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4338%	34.0364%
BLACK LAW	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	22.0683%	31.9648%	26.7881%	26.9035%	23.4623%	25.7180%
BLACKLAW EXTENSION	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	33.4635%	13.1095%	26.9702%
BRIMSDOWN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	21.8759%	18.7645%	11.1229%	16.4463%	45.0615%	19.0289%
BURBO BANK	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	16.7781%	25.0233%	30.4355%
CARRAIG GHEAL	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	29.8118%	45.2760%	48.9277%	45.6254%	40.4211%	46.6097%
CARRINGTON	CCGT_CHP	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	38.7318%	58.0115%	46.6520%
CLUNIE SCHEME	Hydro	Actual	Actual	Actual	Actual	Actual	33.4563%	45.3256%	43.2488%	47.9711%	32.8297%	40.6769%
CLYDE (NORTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.5345%	42.6598%	36.8882%	41.4120%	26.8858%	35.6116%
CLYDE (SOUTH)	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	31.6084%	39.8941%	29.4115%	39.9615%	34.8751%	35.4592%
CONNAHS QUAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	18.5104%	12.8233%	18.3739%	28.2713%	37.4588%	21.7185%
CONON CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	47.5286%	54.2820%	55.5287%	58.9860%	48.6782%	52.8296%
CORRIEGARTH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	22.5644%	30.4133%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.2315%	33.6356%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.6869%	9.7852%	17.5123%	26.4000%	63.0383%	19.8664%
COTTAM	Coal	Actual	Actual	Actual	Actual	Actual	65.0700%	67.3951%	51.4426%	34.4157%	14.9387%	50.3095%
COTTAM DEVELOPMENT CENTRE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	13.7361%	16.0249%	31.3132%	28.2382%	67.2482%	25.1921%
COUR	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.3246%	35.6667%
COWES	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.1743%	0.0956%	0.3135%	0.4912%	0.5319%	0.3264%
CRUACHAN	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	8.4281%	9.6969%	9.0516%	8.8673%	7.1914%	8.7823%
CRYSTAL RIG II	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	40.6845%	50.2549%	47.5958%	48.3836%	40.2679%	45.5546%
CRYSTAL RIG III	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	39.9503%	36.2086%
DAMHEAD CREEK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	45.0617%	77.1783%	67.4641%	64.8983%	68.1119%	66.8248%
DEESIDE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.7551%	17.3035%	13.9018%	17.4579%	27.1090%	18.1722%
DERSALLOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.7728%	34.1494%
DIDCOT B	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	49.0134%	18.6624%	25.5345%	41.1389%	50.1358%	38.5623%
DIDCOT GTS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.0720%	0.0902%	0.2843%	0.4861%	0.0452%	0.1488%
DINORWIG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	15.0990%	15.0898%	15.0650%	14.6353%	15.9596%	15.0846%
DRAX	Coal	Actual	Actual	Actual	Actual	Actual	82.4774%	80.5151%	82.2149%	76.2030%	62.2705%	79.6443%

DUDGEON	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	42.4791%	47.1631%
DUNGENESS B	Nuclear	Actual	Actual	Actual	Actual	Actual	59.8295%	61.0068%	54.6917%	70.7617%	79.3403%	63.8660%
DUNLAW EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.3771%	34.8226%	30.0797%	29.1203%	26.5549%	30.5257%
DUNMAGLASS	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.9713%	35.8822%
EDINBANE WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	29.3933%	39.4785%	31.2458%	35.5937%	32.5009%	33.1135%
EGGBOROUGH	Coal	Actual	Actual	Actual	Actual	Partial	72.6884%	72.1843%	45.7421%	27.0157%	39.7693%	63.5383%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	14.5869%	28.2628%	25.3585%	28.1507%	16.1775%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.3314%	34.0023%
FALLAGO	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	32.9869%	54.8683%	44.7267%	55.7992%	43.2176%	51.7981%
FARR WINDFARM TOMATIN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.0149%	44.7212%	38.5712%	40.9963%	34.1766%	37.9147%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	22.1176%	35.3695%	57.4834%	53.1573%	30.9768%	39.8345%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.1362%	63.3619%	72.8484%	57.6978%	63.2006%	62.5662%
FFESTINOGG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	2.9286%	5.4631%	4.3251%	3.4113%	5.6749%	4.3999%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	61.6386%	49.0374%	45.2435%	27.4591%	8.2478%	40.5800%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	40.2952%	59.9142%	59.4092%	65.1349%	49.6402%	56.3212%
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	13.4800%	14.7097%	12.3048%	15.4323%	11.3046%	13.4982%
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.5600%	33.7451%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.9764%	34.5506%
GARRY CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	48.5993%	55.9308%	64.3828%	60.2772%	61.0498%	59.0859%
GLANDFORD BRIGG	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.3336%	1.5673%	0.5401%	1.8191%	2.7682%	1.3088%
GLEN APP	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.1373%	31.2709%
GLENDOE	Hydro	Actual	Actual	Actual	Actual	Actual	17.3350%	36.3802%	32.3494%	34.8532%	23.8605%	30.3544%
GLENMORISTON	Hydro	Actual	Actual	Actual	Actual	Actual	36.3045%	44.4594%	48.7487%	50.6921%	34.6709%	43.1709%
GORDONBUSH	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	37.8930%	46.5594%	47.7981%	47.7161%	50.4126%	47.3579%
GRAIN	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	25.4580%	41.3833%	44.0031%	39.7895%	53.8227%	41.7253%
GRANGEMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	52.8594%	55.9047%	62.6168%	59.8274%	51.4558%	56.1972%
GREAT YARMOUTH	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	19.0270%	20.7409%	18.6633%	59.8957%	63.5120%	33.2212%
GREATER GABBARD OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	40.1778%	48.3038%	42.1327%	50.2468%	43.1132%	44.5166%
GRIFFIN WIND	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	17.9885%	31.9566%	31.3152%	31.0284%	25.8228%	29.3888%
GUNFLEET SANDS I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	50.1496%	56.6472%	47.0132%	50.4650%	45.7940%	49.2093%
GUNFLEET SANDS II	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	45.0132%	52.2361%	44.7211%	49.0521%	43.9893%	46.2622%
GWYNT Y MOR	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	18.8535%	8.0036%	61.6185%	63.1276%	44.8323%	56.5262%
HADYARD HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	27.6927%	31.9488%	27.7635%	36.6527%	31.4364%	30.3829%
HARESTANES	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	22.2448%	28.6355%	27.8093%	22.5464%	26.3304%
HARTLEPOOL	Nuclear	Actual	Actual	Actual	Actual	Actual	80.2632%	73.7557%	56.2803%	53.8666%	78.0390%	69.3583%
HEYSHAM	Nuclear	Actual	Actual	Actual	Actual	Actual	83.3828%	73.3628%	68.8252%	72.7344%	79.6169%	75.2380%
HINKLEY POINT B	Nuclear	Actual	Actual	Actual	Actual	Actual	61.7582%	68.8664%	70.1411%	67.6412%	71.2265%	68.8829%



HUMBER GATEWAY OFFSHORE WIND FARM	Offshore_Wind	Generic	Generic	Generic	Actual	Actual	0.0000%	0.0000%	0.0000%	62.9631%	59.7195%	57.3959%
HUNTERSTON	Nuclear	Actual	Actual	Actual	Actual	Actual	73.5984%	84.7953%	79.1368%	82.1786%	83.2939%	81.5365%
IMMINGHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	50.1793%	37.8219%	56.8316%	69.4686%	71.9550%	58.8265%
INDIAN QUEENS	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.3423%	0.2321%	0.0876%	0.0723%	0.0847%	0.1348%
KEADBY	CCGT_CHP	Actual	Actual	Generic	Partial	Actual	4.6125%	0.0001%	0.0000%	35.1858%	28.6076%	11.0734%
KILBRAUR	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	45.2306%	51.3777%	54.3550%	50.3807%	46.5342%	49.4309%
KILGALLIOCH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	25.2739%	31.3164%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	32.3429%	45.5356%	44.8205%	53.2348%	27.4962%	40.8997%
KILLINGHOLME (NP)	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	10.6552%	7.4217%	11.6191%	0.0000%	0.0000%	9.8987%
KILLINGHOLME (POWERGEN)	Gas_Oil	Generic	Generic	Generic	Generic	Generic	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
KINGS LYNN A	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	0.0003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0001%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.9115%	40.8749%	34.8629%	16.5310%	44.5413%	39.2164%
LINCS WIND FARM	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	20.3244%	46.5987%	43.8178%	49.1306%	44.5192%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.3807%	33.6286%	49.6644%	39.9829%	64.8597%	41.0920%
LOCHLUICHAIR	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	24.9397%	20.2103%	29.2663%	31.6897%	27.0554%
LONDON ARRAY	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	38.9520%	51.2703%	64.0880%	66.8682%	53.6245%	61.5269%
LYNEMOUTH	Coal	Generic	Generic	Generic	Partial	Generic	0.0000%	0.0000%	0.0000%	68.0196%	0.0000%	58.6875%
MARCHWOOD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	43.3537%	48.6845%	66.4021%	55.0879%	75.4248%	56.7248%
MARK HILL	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	30.1675%	30.2863%	26.7942%	34.0227%	21.9653%	29.0827%
MEDWAY	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	1.0718%	14.5545%	28.0962%	34.1799%	35.1505%	25.6102%
MILLENNIUM	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	42.1318%	52.6618%	53.2636%	48.4038%	44.9764%	48.6806%
NANT	Hydro	Actual	Actual	Actual	Actual	Actual	20.8965%	35.5883%	36.4040%	37.3788%	30.6350%	34.2091%
ORMONDE	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	48.8406%	49.6561%	42.8711%	47.1986%	41.2188%	46.5753%
PEMBROKE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.5434%	60.3928%	67.5346%	64.5596%	77.6478%	64.5459%
PEN Y CYMOEDD	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	26.9446%	31.8733%
PETERBOROUGH	CCGT_CHP	Actual	Actual	Actual	Partial	Actual	0.9506%	1.8311%	1.0929%	4.1032%	1.7914%	1.5718%
PETERHEAD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	31.3766%	41.8811%	0.4858%	23.3813%	42.2292%	32.2130%
RACE BANK	Offshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	45.3062%	48.1055%
RATCLIFFE-ON-SOAR	Coal	Actual	Actual	Actual	Actual	Actual	66.7461%	71.7403%	56.1767%	19.6814%	15.4657%	47.5347%
ROBIN RIGG EAST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	37.4157%	46.7562%	55.3209%	51.9700%	50.5096%	49.7453%
ROBIN RIGG WEST	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	38.2254%	48.0629%	53.4150%	56.0881%	51.5383%	51.0054%
ROCKSAVAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.4820%	2.6155%	4.4252%	19.8061%	58.6806%	21.9044%
RYE HOUSE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	10.7188%	7.4695%	5.3701%	7.7906%	15.6538%	8.6596%
SALTEND	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	81.5834%	69.0062%	67.9518%	55.6228%	77.4019%	71.4533%
SEABANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.2311%	18.2781%	25.6956%	27.2136%	41.6815%	23.7291%
SELLAFIELD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	14.0549%	25.0221%	18.9719%	28.6790%	19.8588%	21.2842%
SEVERN POWER	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.7976%	32.4163%	24.6354%	18.3226%	64.4246%	28.2831%
SHERINGHAM SHOAL	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	36.6431%	49.3517%	46.2286%	53.6184%	46.9715%	47.5173%



SHOREHAM	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	0.0000%	20.7501%	10.2239%	48.9514%	68.9863%	26.6418%
SIZEWELL B	Nuclear	Actual	Actual	Actual	Actual	Actual	96.7260%	82.5051%	84.7924%	98.7826%	81.6359%	88.0078%
SLOY G2 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	9.1252%	14.3471%	15.5941%	13.9439%	8.1782%	12.4721%
SOUTH HUMBER BANK	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	27.9763%	24.3373%	34.4673%	48.6753%	55.3419%	37.0396%
SPALDING	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	34.6976%	33.4800%	39.3092%	47.9407%	60.9748%	40.6492%
STAYTHORPE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	54.4117%	37.6216%	56.6148%	69.4422%	65.7791%	58.9352%
STRATHY NORTH & SOUTH	Onshore_Wind	Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	49.6340%	36.1987%	40.0568%
SUTTON BRIDGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	20.1652%	9.4124%	17.2025%	13.1999%	38.0184%	16.8559%
TAYLORS LANE	Gas_Oil	Actual	Actual	Actual	Actual	Actual	0.2037%	0.0483%	0.0640%	0.1708%	0.8047%	0.1462%
THANET OFFSHORE WIND FARM	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	41.1093%	39.7489%	35.5935%	41.3434%	33.7132%	38.8172%
TODDLBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.7175%	39.5374%	33.7211%	35.0823%	31.3435%	33.8403%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	84.8669%	86.4669%	91.4945%	85.7725%	97.9942%	87.9113%
USKMOUTH	Coal	Actual	Actual	Partial	Actual	Actual	45.1938%	38.9899%	46.9428%	25.5184%	24.3304%	36.5674%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	44.2799%	57.7046%	52.0555%	50.7535%	47.4617%	50.0902%
WALNEY II	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	54.7907%	61.9219%	58.2355%	35.7988%	54.9727%	58.3767%
WEST BURTON	Coal	Actual	Actual	Actual	Actual	Actual	70.5868%	68.9176%	61.5364%	32.7325%	10.1071%	54.3955%
WEST BURTON B	CCGT_CHP	Partial	Actual	Actual	Actual	Actual	21.3299%	30.3021%	46.8421%	59.3477%	54.2878%	53.4925%
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	40.4447%	40.0506%	48.7540%	48.7691%	45.8579%
WESTERMOST ROUGH	Offshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	26.2900%	54.8014%	58.1061%	46.3992%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.2265%	35.1074%	29.8105%	31.8773%	27.2893%	29.9714%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	12.4146%	27.0102%	27.7787%	26.7655%	23.5253%	25.7670%
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	3.4258%	4.4941%	21.5867%	16.1379%	14.4130%	11.6817%

**Table 24: Generic Annual Load Factors**

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

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

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

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

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## Appendix E: Contracted generation changes since the April forecast

This table shows the TEC changes notified between April 2018 and these June tariffs. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table.

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

This table shows only the changes to the version of the TEC register used in this June forecast compared to the TEC register used for the April forecast.

**Table 25: Generation Contracted TEC Changes**

Power Station	MW Change	Node	Generation Zone
Blacklaw Extension	-9	BLKX10	11
Cowes	140	FAWL40	26
Didcot B	-100	DIDC40	25
Liberty Steel Dalzell	18	WISH10	11
Morlais	120	WYLF40	19
Neart Na Gaoithe Offshore Wind Farm	-450	CRYR40	11
Beinn an Tuirc 3	-50	CAAD1Q	7
Sizewell C	-1670	SIZE40	18

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## Appendix F: Transmission company revenues

### National Grid revenue forecast

We seek to provide the detail behind price control revenue forecasts for National Grid, Scottish Power Transmission and SHE Transmission, however the TOs are not presently required to provide a breakdown of their revenue.

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

*Notes:*

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

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

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

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

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

**Table 26 – Indicative National Grid revenue forecast**

Description							Notes
	Regulatory Year	Licence Term	2018/19 (fixed forecast)	Initial Forecast	April Forecast	June Forecast	
Actual RPI							April to March average
RPI Actual		RPIAt					Office of National Statistics
Assumed Interest Rate		It	0.71%	0.56%	1.16%	1.16%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1587.6	1585.2	1585.2	1585.2	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-310.2	-334.0	-334.0	-334.0	Forecast
RPI True Up	A3	TRUt	-6.1	3.3	3.3	3.3	Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.60%	3.50%	3.50%	3.50%	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.40%	3.00%	3.00%	3.00%	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.10%	3.00%	3.00%	3.00%	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.3140	1.3570	1.3570	1.3570	Using HM Treasury Forecast
<b>Base Revenue [A=(A1+A2+A3)*A4]</b>	<b>A</b>	<b>BRt</b>	<b>1670.5</b>	<b>1702.3</b>	<b>1702.3</b>	<b>1702.3</b>	
Pass-Through Business Rates	B1	RBt	1.6	35.1	0.0	0.0	Forecast
Temporary Physical Disconnection	B2	TPDt	0.7	0.0	0.0	0.0	Forecast
Licence Fee	B3	LFt	-0.4	4.5	0.0	0.0	Forecast
Inter TSO Compensation	B4	ITCt	1.3	0.8	0.0	0.0	Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	0.0	Forecast
SP Transmission Pass-Through	B6	TSPt	350.0	390.0	390.0	390.0	Forecast
SHE Transmission Pass-Through	B7	TSHt	366.4	349.4	349.4	349.4	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	318.1	459.9	386.5	387.4	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.5	0.6	0.6	0.6	Forecast
Interconnectors Cap&Floor Revenue Adjustment	B10	TICFt	-6.8		-6.8	-6.8	Forecast
<b>Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9+B10]</b>	<b>B</b>	<b>PTt</b>	<b>1031.5</b>	<b>1240.2</b>	<b>1119.6</b>	<b>1120.6</b>	
Reliability Incentive Adjustment	C1	RIt	4.1	4.2	4.2	4.2	Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt	9.3	8.6	8.6	8.6	Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	1.4	1.6	1.6	1.6	Forecast
<b>Outputs Incentive Revenue [C=C1+C2+C3+C4]</b>	<b>C</b>	<b>OIPt</b>	<b>14.8</b>	<b>14.4</b>	<b>14.5</b>	<b>14.5</b>	
Network Innovation Allowance	D	NIAt	10.5	10.7	10.7	10.7	Forecast
Network Innovation Competition	E	NICFt	32.7	40.5	32.7	32.7	Forecast
Future Environmental Discretionary Rewards	F	EDRt	0.0	2.0	0.0	0.0	Forecast
Transmission Investment for Renewable Generation	G	TIRGt	0.0	0.0	0.0	0.0	Forecast
Scottish Site Specific Adjustment	H	DISt	6.6	0.0	0.0	0.0	Forecast
Scottish Terminations Adjustment	I	TSt	3.1	0.0	0.0	0.0	Forecast
Correction Factor	K	-Kt	-55.5	0.0	0.0	42.5	Calculated by Licensee
<b>Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]</b>	<b>M</b>	<b>TOt</b>	<b>2714.3</b>	<b>3010.2</b>	<b>2879.8</b>	<b>2923.3</b>	
Pre-vesting connection charges	P		44.0	41.9	44.0	44.0	Forecast
<b>TNUoS Collected Revenue [T=M-B5-P]</b>	<b>T</b>		<b>2670.3</b>	<b>2968.4</b>	<b>2835.8</b>	<b>2879.3</b>	

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## Scottish Power Transmission revenue forecast

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

## SHE Transmission revenue forecast

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

## Offshore Transmission Owner & Interconnector revenues

The Offshore Transmission Owner revenue forecast will be updated in November for the Draft tariffs, and will be finalised by 25 January 2019. The indicative OFTO revenue to be collected via TNUoS for 2019/20 is £387.4m, an increase of £1.4m from April. Revenues have been adjusted to take into account an updated RPI forecast.

Under CMP283, TNUoS charges can be adjusted by an amount determined by Ofgem to enable recovery and/or redistribution of interconnector revenue in accordance with the Cap and Floor regime. The interconnector revenue forecast will be updated in November draft tariff forecast, and confirmed by 25 January 2019.

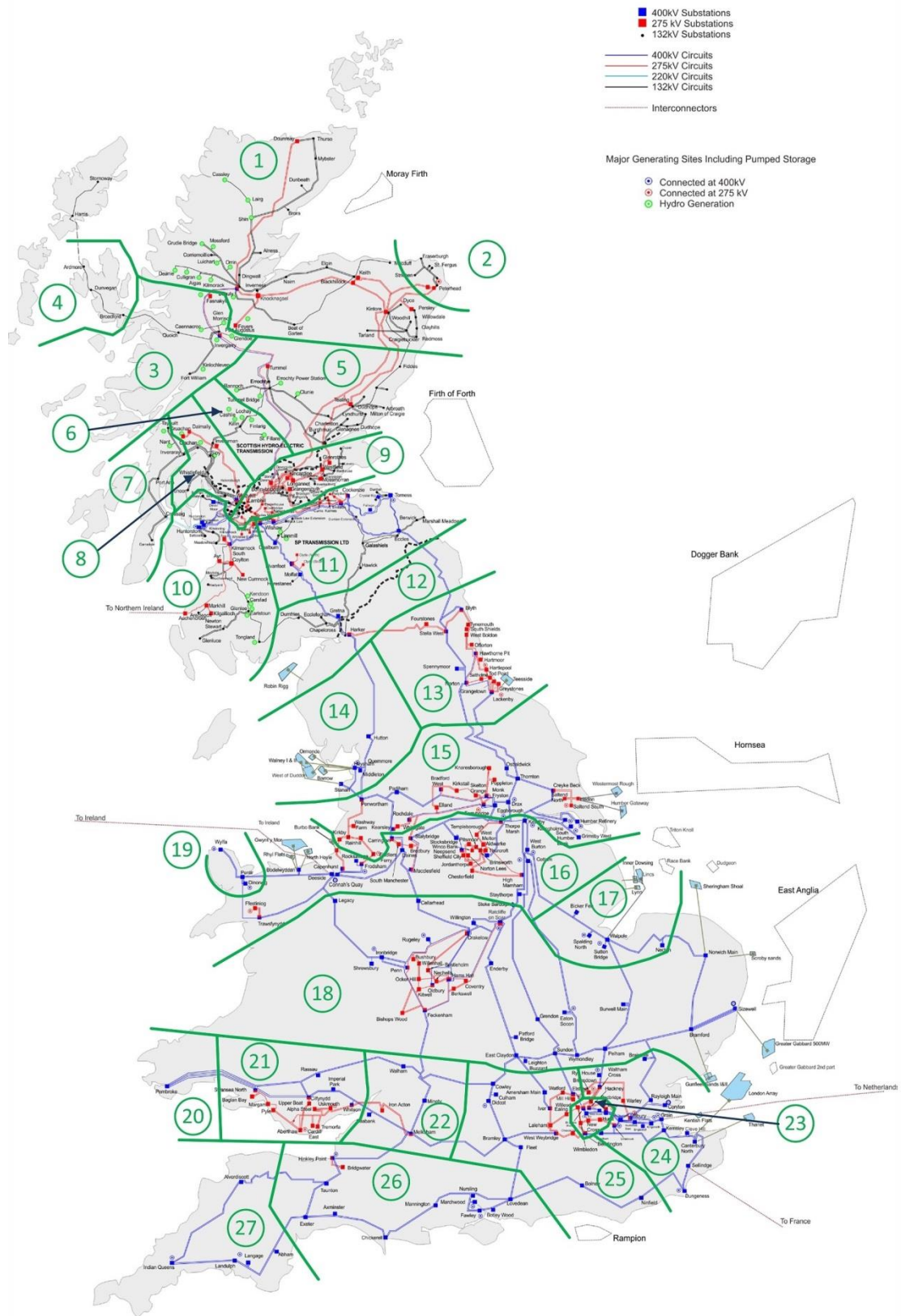
**Table 27 - Offshore Transmission Owner revenues (indicative)**

Offshore Transmission Revenue Forecast (£m)	27/06/2018						Notes
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	
Regulatory Year							
Barrow	5.5	5.6	5.7	5.9	6.3	6.2	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	7.8	7.7	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	13.6	14.1	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	8.7	8.7	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	16.3	14.6	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	20.7	21.4	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	12.6	13.0	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	28.4	29.3	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	41.8	41.4	Current revenues plus indexation
Thanet	78.9	17.5	15.7	19.5	18.6	19.2	Current revenues plus indexation
Lincs		25.6	26.7	27.2	28.2	27.7	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	32.7	29.0	Current revenues plus indexation
West of Duddon Sands			21.3	22.0	22.6	23.3	Current revenues plus indexation
Humber Gateway		35.3	29.3	9.7	12.1	12.0	Current revenues plus indexation
Westermost Rough			11.6	13.2	13.5	Current revenues plus indexation	
Burbo Bank					34.3	57.4	National Grid Forecast
Dudgeon							National Grid Forecast
Race Bank							National Grid Forecast
Forecast to asset transfer to OFTO in 2019/20						48.9	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>387.4</b>	

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

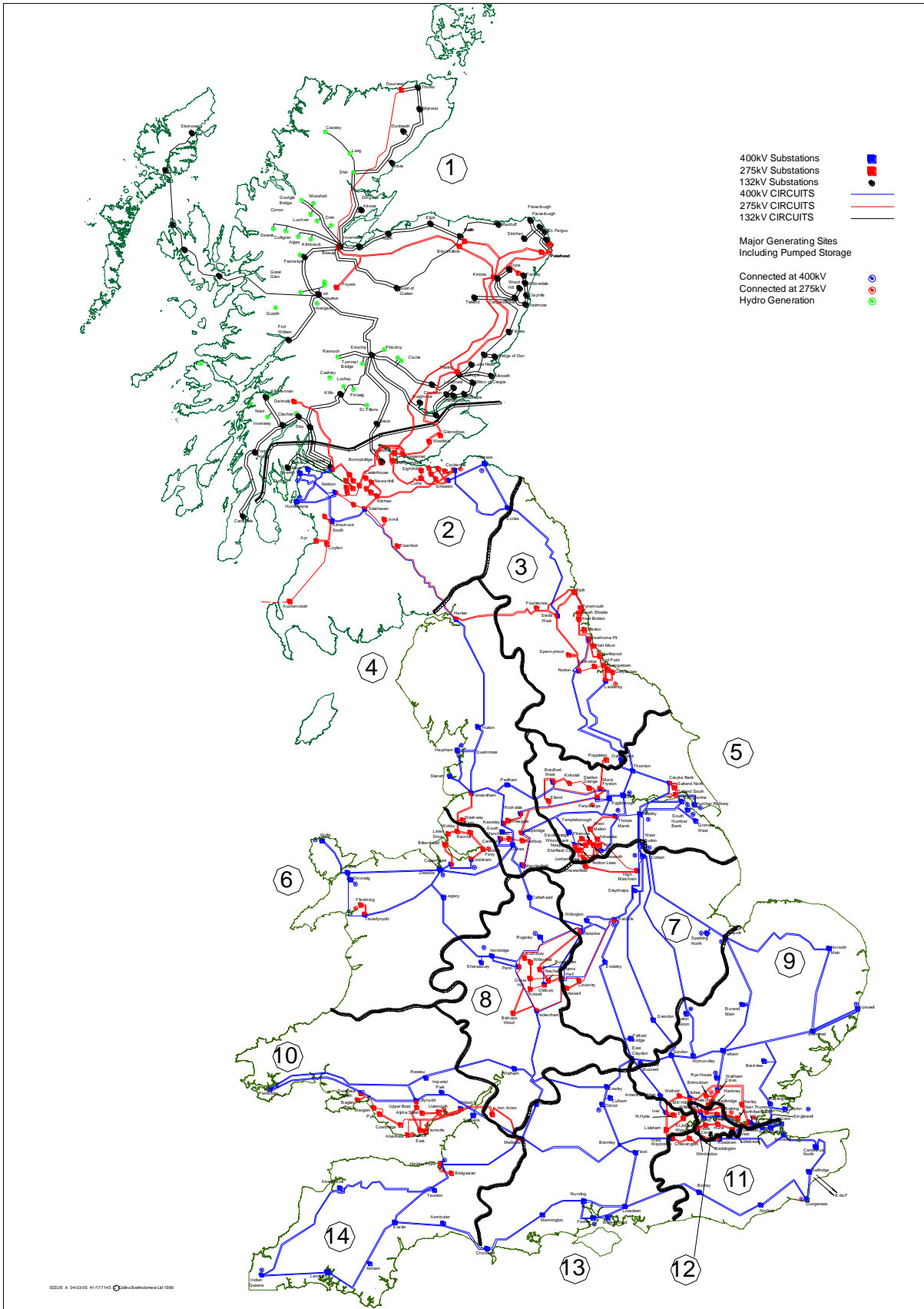
# Appendix G: Generation zones map

Figure A2: GB Existing Transmission System





# Appendix H: Demand zones map



## Appendix I: Parameters affecting TNUoS Tariffs

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

Our intention is to fix the demand charging base at this forecast. However there has been increasing volatility in many of the inputs in recent years (for example, the high winter 2017/18 embedded export volume). This means we may need to adjust the values later to ensure we set tariffs to recover the total allowed revenue.

2019/20 TNUoS Tariff Forecast						
		November 17	April 18	June 18 THIS FORECAST	November 18 (Draft tariffs)	January 19 (Final tariffs)
<b>Methodology</b>		Open to industry governance				
<b>Locational</b>	<b>DNO/DCC Demand Data</b>	Previous year			Week 24 updated	
	<b>Contracted TEC</b>	Latest TEC Register	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	Forecast	NG Best View
	<b>Allowed Revenue</b> <i>(non OFTO changes)</i>	Update financial parameters	Update financial parameters	Latest onshore TO Forecasts	Latest TO Forecasts	From TOs
	<b>Demand Charging Bases</b>	Previous Year	Revised Forecast	Final Forecast	<i>By exception</i>	<i>By exception</i>
	<b>Generation Charging Base</b>	NG Best View	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>	Forecast	Forecast	Fixed Gen Rev £m		