Forecast TNUoS Tariffs for 2018/19

October 2017

nationalgrid

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This information paper provides National Grid's October Forecast Transmission Network Use of System (TNUoS) Tariffs for 2018/19, applicable to transmission connected Generators and Suppliers, effective from 1 April 2018.

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Contents

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.

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Executive Summary

This document contains the latest draft of the Transmission Network Use of System (TNUoS) Tariffs for 2018/19, which will become effective on 1 April 2018. TNUoS charges are paid by transmission connected generators and suppliers for use of the GB Transmission networks.

Total Revenues to be recovered

Total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges is forecast to be £2,661.3m in 2018/19, a decrease of £158.5m from the forecast published in June 2017.

Generation Tariffs

Generation tariffs have been set to recover £430.1m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. There is no change to total generation revenue compared to the June forecast. However, an increase in the generation charging base of 5.3GW, results in an overall average decrease of £0.44/kW to generation tariffs. The Error Margin element of the tariff forecast which is used to calculate the split of revenue to be recovered from generation and demand (the G/D split) remains fixed at 21%.

Demand Tariffs

Demand tariffs have been set to recover £2,231.2m of revenue, a decrease of £158.5m from the June forecast. This reflects the reduction in overall revenue for GB TOs. The average gross demand Half Hourly (HH) tariff is £46.20/kW; the average Embedded Export Tariff (EET) is £29.15/kW; and the average Non Half Hourly (NHH) demand tariff is 6.23p/kWh.

Changes to the Methodology affecting 2018/19 tariffs

There are several CUSC modifications which affect the charging methodology for 2018/19. There are also a number of modifications pending an Ofgem decision which may change the methodology before final tariffs are set.

Approved Modifications: CMP264/265 and CMP268

This is the first forecast we have published following the approval of CMP264 /265, and CMP268.

Under CMP264/265 (changes to embedded benefits) HH demand tariffs are now calculated based on gross demand, and there is a new EET to be paid to suppliers (SVA registered) and embedded generators (<100MW CVA registered) for their average export from generation over the triad periods.

We have published a number of information documents over the summer relating to CMP264/265 on our website including a guidance paper on the implementation on our tariffs, the value of the Avoided GSP Infrastructure Cost (AGIC) and a summary of the historic gross metered demand data under BSC P348/349 modifications[1].

Under CMP268 a new tariff structure is introduced for 'conventional carbon' generation, where the Year Round Not Shared component of the wider tariff is also multiplied by the Annual Load Factor.

Other Modifications

This tariff forecast has been undertaken in accordance with the CUSC charging methodology based on modifications that have been approved.

Modifications CMP282 and CMP261 are waiting for an Authority decision. Indicative impacts of these modifications are discussed in Appendix A.

Modifications CMP251 and CMP283 are waiting for an Authority decision. These are also discussed in Appendix A.

Demand Forecast

Following the methodology change CMP264/265, we have revised our demand forecasting "Monte Carlo" model. We now forecast separate gross demand and embedded exports for each zone.

Our modelling approach takes into account historical trends of metered triad demand and export volumes (2014/15 – 2016/17) provided by Elexon as part of the BSC P348/349 modifications. The model also includes other factors such as weather patterns, future demand shifts on the transmission system and expected levels of renewable generation.

For 2018/19 we are forecasting average system gross triad demand of 52GW, average HH gross triad demand of 19.8GW, embedded export generation of 6.5GW and NHH demand of 24.2TWh.

The values of gross demand and embedded exports are consistent with the value of net demand used in our June Forecast. The value of NHH demand has also remained stable.

Drivers of changes to the Tariff forecast

Changes to these forecast tariffs in relation to our June tariff forecast

[1] *See the 2018/19 section on https://www.nationalgrid.com/uk/electricity/charging-and-methodology/transmission-network-use-system-tnuos-charges*

have predominantly been influenced by:

- Methodology changes though CMP264/265 affecting the structure and value of demand tariffs
- Methodology changes through CMP268 reducing the locational revenue recovered from generation (making the generation residual less negative)
- An increase of 3.6GW in contracted transmission connected generation[2], mainly in the Midlands, leading to higher generation locational charges in the North.

Next forecast

Our next forecast of 2018/19 TNUoS tariffs will be our Draft tariffs in December 2017, followed by Final tariffs in January 2018.

These tariffs will reflect the latest methodology of the CUSC at the time.

Significant updates expected in the December tariffs will include Week 24 demand data and our latest view of TEC volumes, which will affect the locational tariffs for generation and demand.

Ofgem has been served with a claim for judicial review concerning its decision to approve WACM4 of CUSC modifications CMP264 and CMP265. As stated on their website: "Ofgem's decision to approve WACM4 of CUSC modifications CMP264 and CMP265 stands unless quashed by the court".[3]

We will also publish a revised five-year forecast of TNUoS tariffs in November 2017.

The latest timetable can be found on our website.[4]

Feedback

This tariff forecast is the second in our new report format, which has been redesigned in order to be easier to navigate and read for all interested parties. 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, if you have any questions on this document or whether you still welcome webinar sessions following each forecast.

[2] This is the volume of TEC on the published TEC Register, which is different to the generation charging base. The charging base is our 'best view' of which out of those contracted generators are likely to connect on time.

[3] 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

[4] Our revised forecast publication timetable is available on our website: http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589940926

Demand Tariffs

Table 1: Demand tariffs

The breakdown of the HH tariff into the peak and year round components are found in Appendix C.

Please note that these tariffs now take into account the changes to the charging methodology directed by CMP264/265 and are not directly comparable to the June Forecast Demand Tariff figures.

Zone	Zone Name	Gross HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)	Embedded Export Tariff (£/kWh)
1	Northern Scotland	42.625828	5.685964	27.958110
2	Southern Scotland	25.070187	3.379183	10.402469
3	Northern	36.695152	4.850815	22.027435
4	North West	43.772060	5.877395	29.104342
5	Yorkshire	43.584369	5.721052	28.916651
6	N Wales & Mersey	45.186145	5.886433	30.518427
7	East Midlands	47.142520	6.297143	32.474802
8	Midlands	48.600885	6.705442	33.933167
9	Eastern	49.119669	7.112924	34.451952
10	South Wales	46.533030	5.640875	31.865312
11	South East	52.267998	7.736564	37.600280
12	London	54.590747	6.071088	39.923029
13	Southern	53.551076	7.335475	38.883359
14	South Western	53.611446	7.814511	38.943729

Tariffs include small gen tariff of:	0.591801	0.079965
Residual charge for gross demand:	£ 46.655917	

1.1. Changes since the previous demand tariffs forecast

Following the implementation of CMP264/265 into the TNUoS demand tariffs, the way in which we now charge against demand has been altered to reflect a gross HH demand tariff and a separate embedded export payment. This and the changes to revenue have impacted the level of tariff charges which vary by zone.

The average HH gross tariff is now £46.20/kW, and compared to the June forecast the average NHH tariff has decreased by 0.77p/kW. The new EET carries an average value of £29.15/kW and against our forecast export volumes this will result in £190m to be paid to embedded generators/suppliers and to be recovered through the demand tariffs. More information on the causes of specific zonal fluctuations is detailed in the HH and NHH sections below.

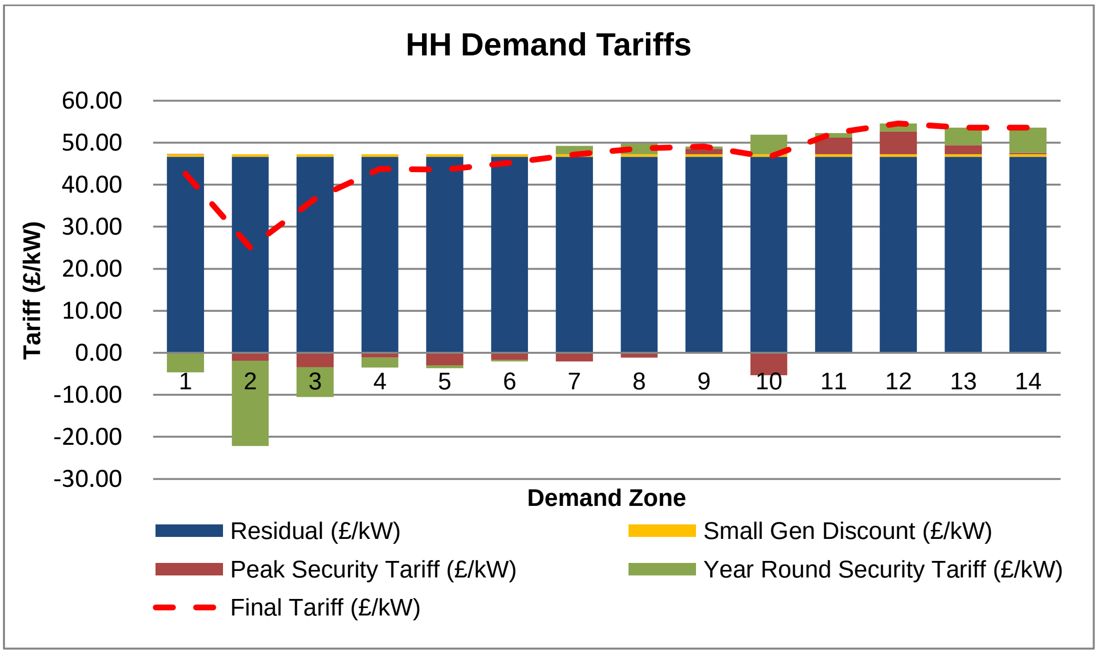
1.2. Gross half hourly demand tariffs

Table 2 and Figure 1 show the gross HH demand tariffs 2018/19 forecast with the CMP264/265 methodology and the associated locational and residual components of our HH demand charge.

Table 2 – Gross HH demand tariffs

Zone	Peak Security Tariff (£/kW)	Year Round Security Tariff (£/kW)	Residual (£/kW)	Small Gen Discount (£/kW)	Final Tariff (£/kW)
1	0.04	-4.66	46.66	0.592	42.63
2	-1.88	-20.30	46.66	0.592	25.07
3	-3.44	-7.11	46.66	0.592	36.70
4	-1.16	-2.31	46.66	0.592	43.77
5	-2.93	-0.73	46.66	0.592	43.58
6	-1.66	-0.40	46.66	0.592	45.19
7	-2.08	1.98	46.66	0.592	47.14
8	-1.18	2.53	46.66	0.592	48.60
9	1.27	0.60	46.66	0.592	49.12
10	-5.35	4.64	46.66	0.592	46.53
11	3.99	1.03	46.66	0.592	52.27
12	5.39	1.96	46.66	0.592	54.59
13	2.16	4.14	46.66	0.592	53.55
14	0.30	6.07	46.66	0.592	53.61

Figure 1 - Gross HH demand tariffs



As outlined above the HH demand tariff is now based on gross chargeable demand, not net demand (gross – embedded export) as previously reflected in the June forecast. The average HH gross demand tariff of £46.20/kW represents a decrease of £6.57/kW, this is largely due to the charging methodology changing from net to gross demand, as well as a significant decrease in the total revenue forecast to be recovered. Changes to the location of generation (please see the generation tariffs section later in this document) has also contributed to this overall reduction. Larger variations can be seen in zones 1 and 2 (Scotland) which have reduced by £9.51/kW and £8.92/kW respectively due to the effect of larger volumes of embedded generation.

The residual element of the tariff has decreased by £5.55/kW, again this is primarily driven by the change to gross demand volumes and reductions in the total revenue forecast. This is slightly offset by the inclusion of the embedded export revenue within the HH demand residual as part of the total revenue to be recovered for demand. The level of embedded export volumes during triads and the associated zonal tariff will have an impact on HH demand tariffs.

As the locational element of HH demand tariffs is typically very small compared to the residual element, changes to HH demand tariffs were negligible in most zones. However following the CMP264/265 methodology, exceptions to this can be seen in Zone 1 (Scotland) where compared to the previous net methodology in the June forecast, the locational value has decreased by £7.03/kW.

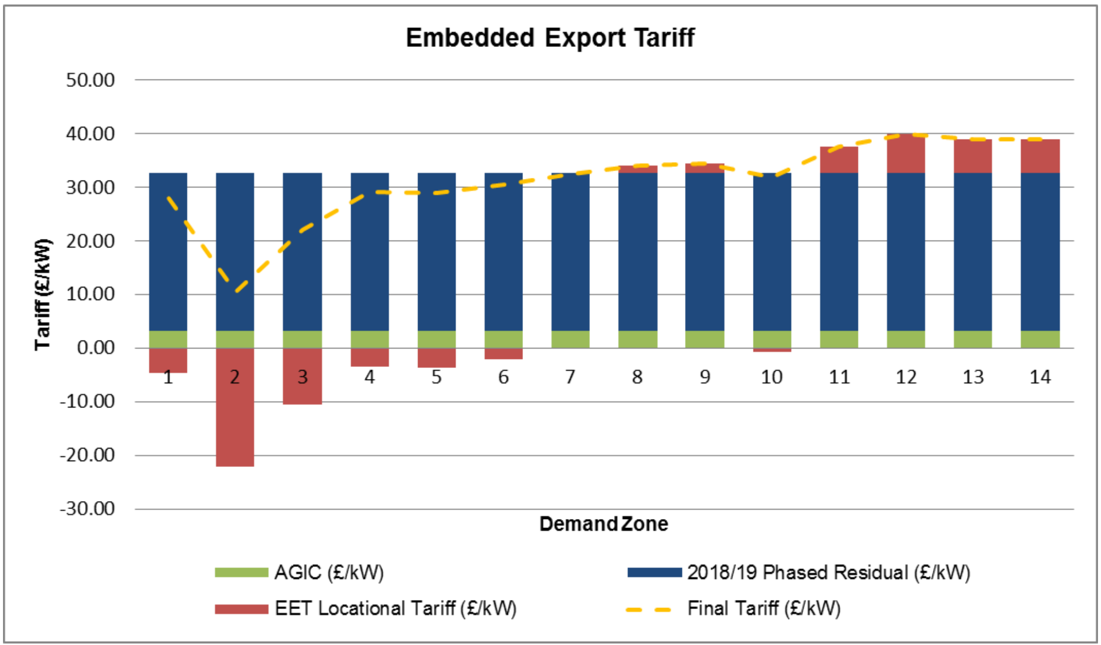
1.3. Embedded export tariff

Table 3 and Figure 2 show the 2018/19 EET forecast following the CMP 264/265 methodology and the associated elements of our revised demand charging principles.

Table 3 – Embedded export tariff

Zone	EET Locational Tariff (£/kW)	AGIC (£/kW)	2018/19 Phased Residual (£/kW)	Final Tariff (£/kW)
1	-4.62	3.22	29.36	27.96
2	-22.18	3.22	29.36	10.40
3	-10.55	3.22	29.36	22.03
4	-3.48	3.22	29.36	29.10
5	-3.66	3.22	29.36	28.92
6	-2.06	3.22	29.36	30.52
7	-0.11	3.22	29.36	32.47
8	1.35	3.22	29.36	33.93
9	1.87	3.22	29.36	34.45
10	-0.71	3.22	29.36	31.87
11	5.02	3.22	29.36	37.60
12	7.34	3.22	29.36	39.92
13	6.30	3.22	29.36	38.88
14	6.36	3.22	29.36	38.94

Figure 2 – Embedded Export Tariff



Under CMP 264/265 the amount of metered embedded generation exports produced at triad by suppliers and embedded generators (<100MW) will determine the amount paid through the EET. The money to be paid out through the EET will be recovered through demand tariffs, which will affect the price of HH and NHH demand tariffs.

Following CMP264/265 the EET is a new tariff payable to embedded exports for HH demand customers and CVA registered embedded generators (<100MW) only. This tariff represents the revenue for the embedded export volume produced during triad periods. Embedded export generation produced by embedded generators less than 100MW will now be treated as a separate export volume.

As per the CMP264/265 methodology, the tariff uses the locational demand elements with the addition of the phased 2017/18 residual and the Avoided GSP Infrastructure Cost (AGIC). We published the value of the AGIC and the phased residual in a letter in October 2017.[**]

The average EET is £29.15/kW in which the locational demand element has a high impact on the level of the zonal tariff cost. This can be seen mostly in zone 2 (Scotland) where the tariff it at its lowest price of £10.40/kW but where the locational element is at its highest in zone 12 so is the tariff at £39.92/kW.

1.4. NHH demand tariffs

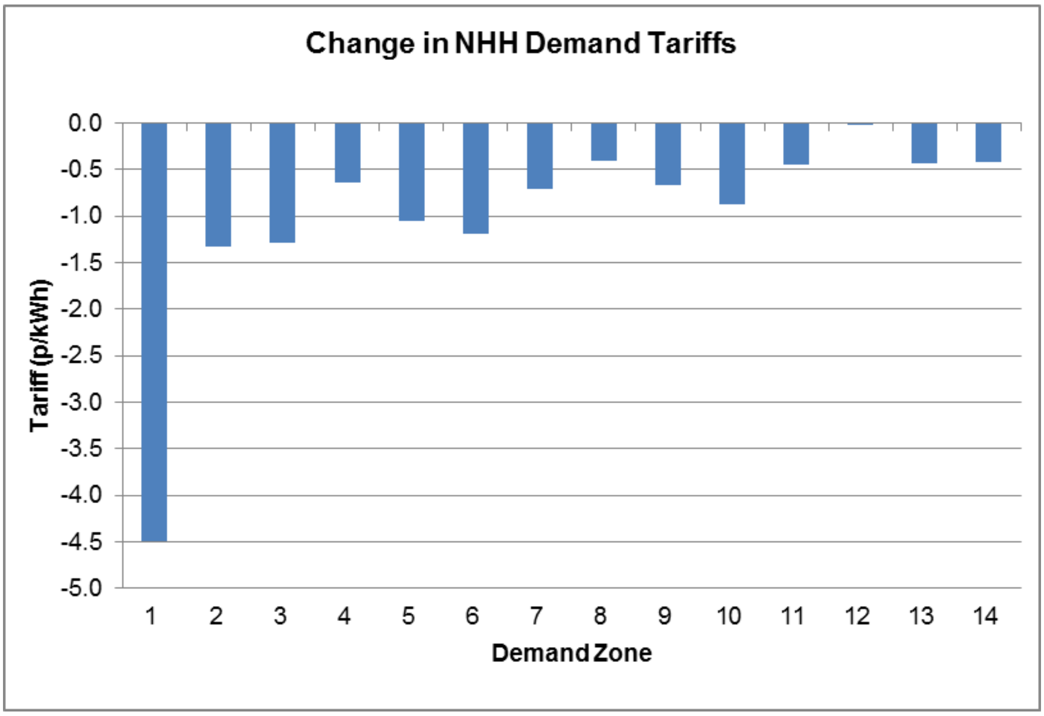
Table 4 and Figure 3 show the difference between the NHH demand tariffs forecast in June and this 2018/19 forecast in October.

[**] *Please see the 2018/19 charging year tariff forecasts section at* https://www.nationalgrid.com/uk/electricity/charging-and-methodology/transmission-network-use-system-tnuos-charges

Table 4 - NHH demand tariff changes

Zone	Zone Name	2018/19 June Forecast (p/kWh)	2018/19 October Forecast (p/kWh)	Change (p/kWh)
1	Northern Scotland	10.18	5.69	-4.50
2	Southern Scotland	4.71	3.38	-1.33
3	Northern	6.14	4.85	-1.29
4	North West	6.51	5.88	-0.64
5	Yorkshire	6.78	5.72	-1.06
6	N Wales & Mersey	7.08	5.89	-1.20
7	East Midlands	7.01	6.30	-0.71
8	Midlands	7.12	6.71	-0.41
9	Eastern	7.78	7.11	-0.67
10	South Wales	6.52	5.64	-0.88
11	South East	8.18	7.74	-0.45
12	London	6.09	6.07	-0.02
13	Southern	7.77	7.34	-0.44
14	South Western	8.23	7.81	-0.42

Figure 3 - NHH demand tariff changes



The methodology for NHH demand tariffs remains the same, except the revenue to be recovered per zone is calculated after calculating the amounts to be recovered from gross HH tariffs and paid out through the EET. The weighted average NHH tariff is 0.77p/kWh lower than in the June forecast. This decrease is attributable to the CMP264/265 charging methodology change to HH demand moving from chargeable net to gross demand. The revised gross chargeable demand forecast in HH demand and the phased residual within the EET has reduced the revenue required to be collected from the NHH charging base. Compared to the June forecast, there has been a very slight decrease in the forecasted NHH output of 0.024 TWh, the most notable zones affected by these variations are 2 and 12 which have a minimal impact on the tariffs.

The impact of CMP264/265 on NHH is seen mostly in zone 1 (northern Scotland) where the effect of high embedded generation export volumes being treated separately (under the EET) from the chargeable gross HH demand has resulted in a reduction of 4.50p/kWh

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

Generation tariffs

This section summarises the October generation tariffs for 2018/19, how these tariffs were calculated and how they have changed from the June forecast.

1.5. Generation wider tariffs

Table 5 - Generation wider tariffs

Under the current methodology each generator has its own load factor as listed in Appendix D, which have been updated and are now the values that will be used for 2018/19 tariffs. The 80% and 40% load factors used in this table are for illustration only.

						Example Tariffs:		
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	2.241534	19.713585	15.377881	-2.337478	27.977229	31.052805	20.925837
2	East Aberdeenshire	4.493625	10.286068	15.377881	-2.337478	22.687306	25.762882	17.154830
3	Western Highlands	1.718980	18.661795	15.377881	-2.337478	26.613242	29.688818	20.505120
4	Skye and Lochalsh	1.734185	18.661795	21.196840	-2.337478	31.283614	35.522982	26.324080
5	Eastern Grampian and Tayside	2.733254	15.780106	14.954896	-2.337478	24.983777	27.974756	18.929460
6	Central Grampian	3.471545	14.914731	14.666316	-2.337478	24.798904	27.732168	18.294730
7	Argyll	3.139357	11.744597	24.331456	-2.337478	29.662722	34.529013	26.691817
8	The Trossachs	3.485394	11.744597	13.541154	-2.337478	21.376518	24.084748	15.901515
9	Stirlingshire and Fife	2.070737	8.812135	12.887017	-2.337478	17.092580	19.669983	14.074393
10	South West Scotlands	2.393557	9.503815	13.011889	-2.337478	18.068642	20.671020	14.475937
11	Lothian and Borders	3.458965	9.503815	7.441956	-2.337478	14.678104	16.166495	8.906004
12	Solway and Cheviot	1.872723	5.515458	7.419831	-2.337478	9.883476	11.367442	7.288536
13	North East England	3.655606	3.273478	4.026336	-2.337478	7.157978	7.963245	2.998249
14	North Lancashire and The Lakes	1.456718	3.273478	2.570818	-2.337478	3.794677	4.308840	1.542731
15	South Lancashire, Yorkshire and Humber	4.255805	1.224412		-2.337478	2.897857	2.897857	-1.847713
16	North Midlands and North Wales	3.343571	-0.250677		-2.337478	0.805551	0.805551	-2.437749
17	South Lincolnshire and North Norfolk	2.090057	-0.187801		-2.337478	-0.397662	-0.397662	-2.412598
18	Mid Wales and The Midlands	1.213214	0.109926		-2.337478	-1.036324	-1.036324	-2.293508
19	Anglesey and Snowdon	3.582852	0.177756		-2.337478	1.387578	1.387578	-2.266376
20	Pembrokeshire	8.301451	-4.582854		-2.337478	2.297689	2.297689	-4.170620
21	South Wales & Gloucester	5.288730	-4.667698		-2.337478	-0.782906	-0.782906	-4.204557
22	Cotswold	2.164427	2.332048	-7.067750	-2.337478	-3.961612	-5.375162	-8.472408
23	Central London	-5.574745	2.332048	-6.261715	-2.337478	-11.055956	-12.308299	-7.666373
24	Essex and Kent	-3.954549	2.332048		-2.337478	-4.426389	-4.426389	-1.404659
25	Oxfordshire, Surrey and Sussex	-1.408390	-2.526834		-2.337478	-5.767335	-5.767335	-3.348212
26	Somerset and Wessex	-2.157555	-4.571951		-2.337478	-8.152594	-8.152594	-4.166259
27	West Devon and Cornwall	-1.564246	-6.853369		-2.337478	-9.384419	-9.384419	-5.078826
		Small Generation Discount (£/kW)			11.079610			

1.6. Changes since the last generation tariffs forecast

The following section provides details of the wider and local generation tariffs for 2018/19 and how these have changed compared with the June forecast.

CMP268

The Authority approved CMP268[††] which has created two new charging categories of generator, “Conventional Carbon” and “Conventional Low Carbon”. Conventional Carbon generators (e.g. CCGT, Coal, OCGT, Pump Storage, CHP, Biomass, Oil) now pay the Year Round Not Shared element multiplied by their ALF.

The charging arrangements for Conventional Low Carbon (e.g. Nuclear, Hydro) and Intermittent generators remain as they were before CMP 268 was approved.

For more information, please see the Background to TNUoS Charging section below.

Generation wider zonal tariffs

Table 6 and Figure 4 show the changes in generation wider TNUoS tariffs between June and this October 2018/19 forecast.

Contracted TEC has increased by around 3.6GW from June to October, which has affected system flows in the Transport model. The increases of over 1GW in zone 2, and 2GW in zone 15 have had a significant impact. In Scotland, Peak tariffs have increased by £1 - £6 in Scotland, and both the Peak and Year Round tariffs have increased by around £1 each in zones 13 to 19.

The combined effect of both of these TEC increases has further concentrated the volume of generation in Central England, which increases particularly Year Round tariffs in the extremities of the network in the North and South.

As an example, Table 6 and Figure 4 show how the tariffs change for a conventional generator with an 80% load factor in June to a Conventional Low Carbon generator in October, and an intermittent generator with a 40% load factor. Under the Transmit methodology each generator has its own load factor and the 80% and 40% load factors used here are only for illustration.

Please note that we have not included a comparison between June and October of the Conventional Carbon and Conventional Low Carbon, so this is not a direct comparison between forecasts.

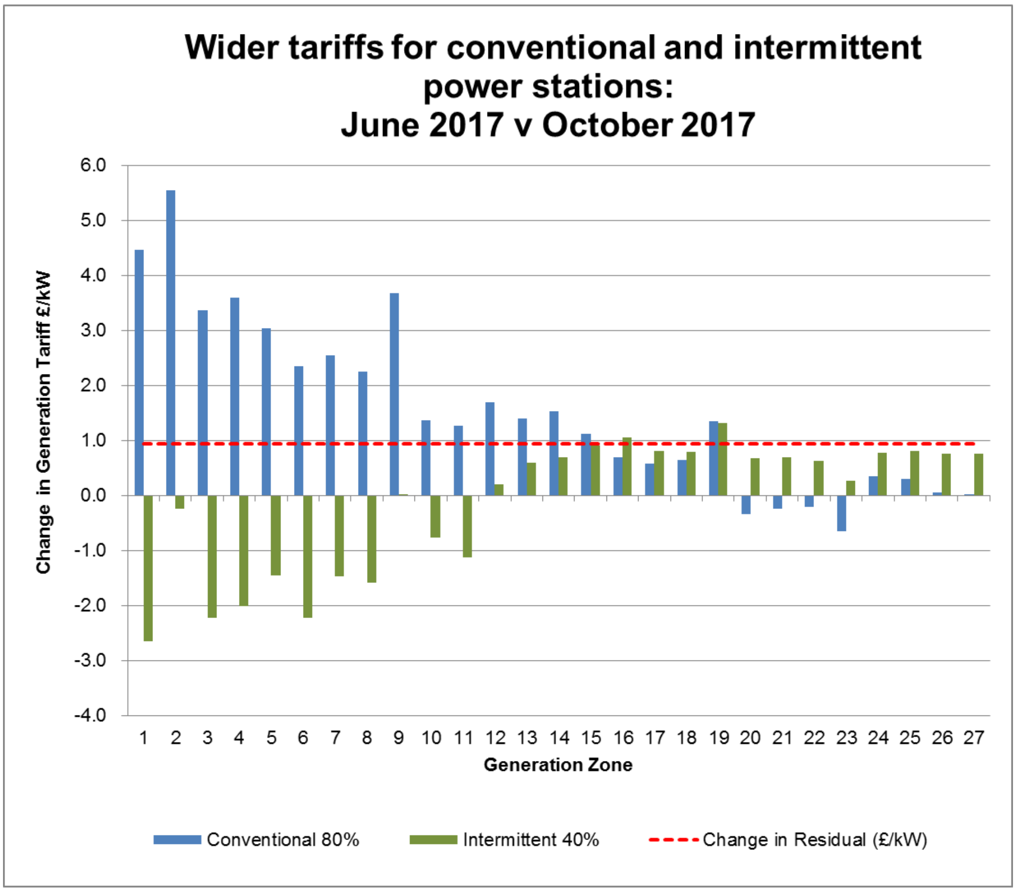
On average generation tariffs have reduced by £0.44/kW due to an increase in the generation charging base of just over 4.2GW.

[††] https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code/modifications/cmp268-recognition-sharing

Table 6 – Generation tariff changes

		Generation Wider Tariffs (£/kW)						
		Conventional 80%			Intermittent 40%			
Zone	Zone Name	2018/19 June forecast (£/kW)	2018/19 October forecast (£/kW)	Change (£/kW)	2018/19 June forecast (£/kW)	2018/19 October forecast (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	26.59	31.05	4.46	23.58	20.93	-2.65	0.94
2	East Aberdeenshire	20.22	25.76	5.54	17.39	17.15	-0.24	0.94
3	Western Highlands	26.32	29.69	3.36	22.73	20.51	-2.23	0.94
4	Skye and Lochalsh	31.93	35.52	3.59	28.34	26.32	-2.01	0.94
5	Eastern Grampian and Tayside	24.93	27.97	3.04	20.38	18.93	-1.45	0.94
6	Central Grampian	25.38	27.73	2.36	20.51	18.29	-2.22	0.94
7	Argyll	31.99	34.53	2.54	28.15	26.69	-1.46	0.94
8	The Trossachs	21.84	24.08	2.25	17.48	15.90	-1.58	0.94
9	Stirlingshire and Fife	15.99	19.67	3.68	14.07	14.07	0.01	0.94
10	South West Scotlands	19.30	20.67	1.37	15.24	14.48	-0.76	0.94
11	Lothian and Borders	14.89	16.17	1.28	10.03	8.91	-1.12	0.94
12	Solway and Cheviot	9.67	11.37	1.70	7.09	7.29	0.20	0.94
13	North East England	6.56	7.96	1.41	2.40	3.00	0.60	0.94
14	North Lancashire and The Lakes	2.78	4.31	1.53	0.85	1.54	0.69	0.94
15	South Lancashire, Yorkshire and Humber	1.77	2.90	1.13	-2.76	-1.85	0.91	0.94
16	North Midlands and North Wales	0.10	0.81	0.70	-3.49	-2.44	1.05	0.94
17	South Lincolnshire and North Norfolk	-0.97	-0.40	0.57	-3.23	-2.41	0.82	0.94
18	Mid Wales and The Midlands	-1.68	-1.04	0.65	-3.09	-2.29	0.79	0.94
19	Anglesey and Snowdon	0.04	1.39	1.34	-3.59	-2.27	1.32	0.94
20	Pembrokeshire	2.63	2.30	-0.33	-4.86	-4.17	0.69	0.94
21	South Wales & Gloucester	-0.54	-0.78	-0.25	-4.91	-4.20	0.70	0.94
22	Cotswold	-5.17	-5.38	-0.21	-9.10	-8.47	0.63	0.94
23	Central London	-11.66	-12.31	-0.64	-7.93	-7.67	0.27	0.94
24	Essex and Kent	-4.78	-4.43	0.36	-2.18	-1.40	0.78	0.94
25	Oxfordshire, Surrey and Sussex	-6.07	-5.77	0.30	-4.16	-3.35	0.81	0.94
26	Somerset and Wessex	-8.22	-8.15	0.06	-4.92	-4.17	0.76	0.94
27	West Devon and Cornwall	-9.41	-9.38	0.03	-5.83	-5.08	0.76	0.94

Figure 4 - Variation in generation zonal tariffs



Onshore local tariffs for generation

2.1. Onshore Local Substation Tariffs

Local substation tariffs reflect the cost of the first transmission substation to which transmission connected generators connect. They are increased each year by Average May – October RPI, so have been updated from the June forecast to reflect latest forecast RPI for the period May 2017 to October 2017.

Table 7 - Local substation tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.191605	0.109610	0.078976
<1320 MW	Redundancy	0.422090	0.261150	0.189930
>=1320 MW	No redundancy	0	0.343677	0.248548
>=1320 MW	Redundancy	0	0.564230	0.411841

2.2. 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 local circuits have been charged through a one off charge, these are listed in Table 8.

Table 8 - Onshore local circuit tariffs

The largest changes to local circuit tariffs are to An Suidhe (-£3.83), Fallago (-£0.74), Gordonbush (-£0.53), Griffin Wind (£4.95) and Necton (-£1.43). These have been caused by the changes to system flows generated by the TEC increases in Scotland and the Midlands.

All other local circuit tariffs remain relatively stable.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	4.096995	Dinorwig	2.289711	Kilmorack	0.188474	Kype Muir	1.415515
Aigas	0.624158	Dunlaw Extension	1.433123	Langage	0.627477	Middle Muir	1.891664
An Suidhe	-0.911354	Dunhill	1.366908	Lochay	0.349230	Dorenell	2.002796
Arecleoch	1.982091	Dumnaglass	1.771805	Luichart	0.548697	Millennium South	0.899268
Baglan Bay	0.725636	Edinbane	6.533826	Mark Hill	0.835581	Aberdeen Bay	2.488266
Beinneun Wind Farm	1.433097	Earlshaugh Wind Farm	3.597936	Margree	5.745649	Killingholme	0.677069
Bhlaraidh Wind Farm	0.627980	Ewe Hill	1.311433	Marchwood	0.364361	Middleton	0.107505
Black Hill	0.823372	Fallago	0.191273	Millennium Wind	1.742662		
BlackCraig Wind Farm	6.007572	Farr	3.402585	Moffat	0.164040		
Black Law	1.667575	Fernoch	4.198372	Mossford	2.749193		
BlackLaw Extension	3.536308	Ffestiniogg	0.241444	Nant	2.395571		
Bodelwyddan	0.109805	Finlarig	0.305576	Necton	-0.356936		
Carrington	-0.030889	Foyers	0.718600	Rhigos	0.096778		
Clyde (North)	0.104659	Galawhistle	1.411472	Rocksavage	0.016887		
Clyde (South)	0.121033	Glendoe	1.755415	Saltend	0.325403		
Corriegarth	3.008662	Glenglass	9.267413	South Humber Bank	0.903058		
Corriemoillie	1.589153	Gordonbush	0.578820	Spalding	0.266346		
Coryton	0.049583	Griffin Wind	4.079805	Strathbrora	0.427469		
Cruachan	1.805974	Hadyard Hill	2.641489	Stronelairg	1.403544		
Crystal Rig	0.031390	Harestanes	2.394748	Strathy Wind	2.058713		
Culligran	1.654034	Hartlepool	0.573697	Wester Dod	0.356126		
Deanie	2.717342	Hedon	0.172684	Whitelee	0.101283		
Dersalloch	2.298804	Invergarry	1.354681	Whitelee Extension	0.281565		
Didcot	0.497305	Kilgallioch	1.004385	Gills Bay	2.403355		

Table 9 - CMP203: Circuits subject to one-off charges

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

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

Offshore local tariffs for generation

3.1. 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) and indexed by average May to October RPI each year, so have been updated from the June forecast to reflect latest forecast RPI for the period May 2017 to October 2017. Offshore local generation tariffs associated with OFTOs yet to be appointed will be calculated following their appointment.

Table 10 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.721088	40.396727	1.003106
Greater Gabbard	14.476133	33.264728	0.000000
Gunfleet	16.710105	15.341185	2.867356
Gwynt Y Mor	17.629613	17.367347	0.000000
Lincs	14.429434	56.494534	0.000000
London Array	9.822495	33.454870	0.000000
Ormonde	23.869459	44.466566	0.354361
Robin Rigg East	-0.441553	29.249094	9.065641
Robin Rigg West	-0.441553	29.249094	9.065641
Sheringham Shoal	23.062034	27.046363	0.587908
Thanet	17.562577	32.725358	0.787815
Walney 1	20.600474	41.025791	0.000000
Walney 2	20.450653	41.387231	0.000000
West of Duddon Sands	7.949161	39.224181	0.000000
Westermost Rough	16.738261	28.313974	0.000000
Humber Gateway	14.029142	31.654419	0.000000

Background to TNUoS charging

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

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

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

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

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

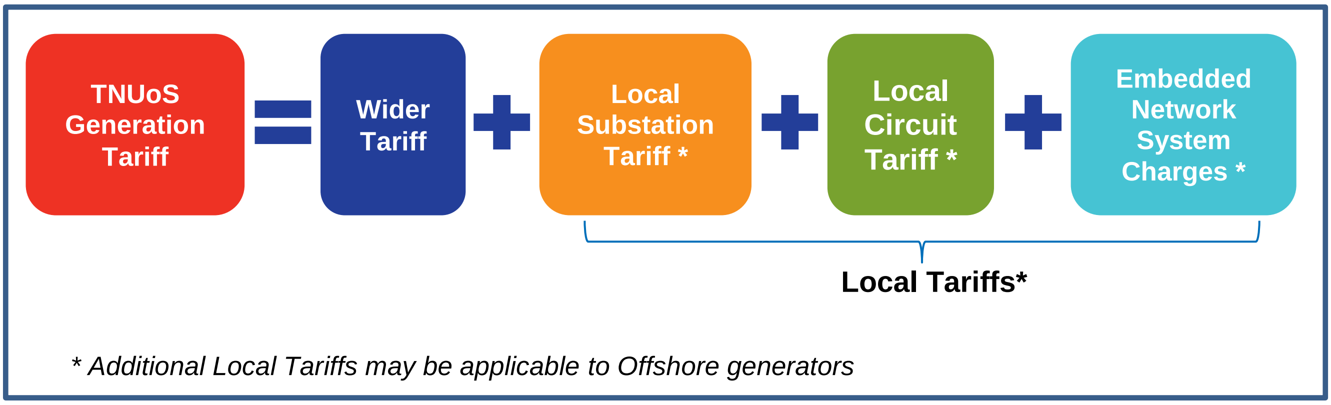
4.1. Generation charging principles

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

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

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

TNUoS tariffs are made up of two general components, the **Wider Tariff**, and **Local Tariffs**.



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

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

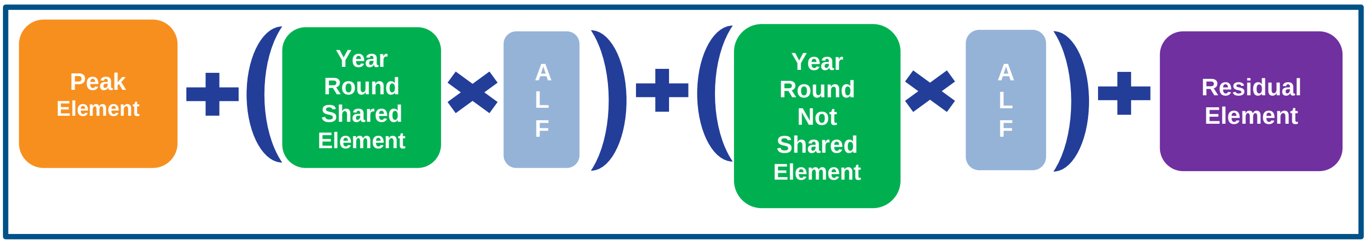
The Wider Tariff

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

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

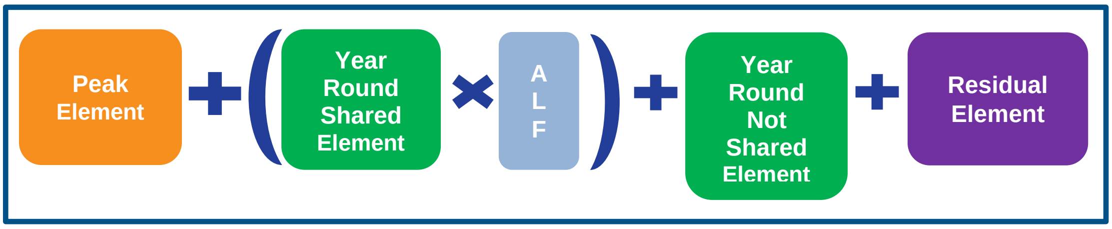
Conventional Carbon Generators

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



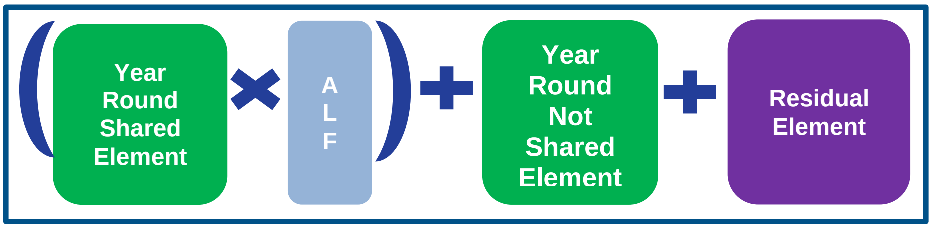
Conventional Low Carbon Generators

(Hydro, Nuclear)



Intermittent Generators

(Wind, Wave, Tidal)



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

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

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

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

The Annual Load Factors used in the October tariffs are listed in paragraph 5.7 and section 8.1.

Local Substation Tariffs

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

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

Local Circuit Tariffs

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

Embedded Network System Charges

If a generator is not connected directly to the transmission network, they will have a BEGA connection agreement allowing them 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 a map of the 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.

4.2. Demand charging principles

Demand is charged in different ways depending on what kind of meter the end user has. 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.

4.3. HH gross demand tariffs

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

HH metered customers tend to be large industrial users, however as the rollout of smart meters progresses, more domestic demand will become HH metered.

4.4. 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 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 Cost. The final zonal EET is floored at £0/kW for the avoidance of negative tariffs and is applied to the metered triad volumes of embedded exports for each demand zone. The money to be paid out through the EET will be recovered through demand tariffs.

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

For suppliers any embedded export payment will be fed into a net demand charge (gross demand – payment for embedded export) which will be capped at the level of the total demand charge so not to exceed the demand charge. Embedded generators (<100MW CVA registered) will receive payment following the final reconciliation process for the amount of embedded export during triads.

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

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.

4.5. NHH demand tariffs

NHH metered customers are charged based on their average demand usage between 16:00 – 19:00 on every day of the year. NHH customers 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.

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.

Updates to revenue & the charging model since the last forecast

Since the June forecast tariffs were published we have updated allowed revenue for onshore and offshore Transmission Owners, the network circuits model, the demand and generation charging bases, transport model generation and circuits, as well as RPI and exchange rates.

The Tariff and Transport model has been updated to reflect the CMP264/265 methodology which changes demand from net to gross and separates the embedded export volume through the new Embedded Export Tariff, and CMP268. There have been no changes to the transport model demand, or the error margin that is used to calculate the proportion of revenue to be recovered from generation and demand (G/D split).

5.1. Changes affecting the locational element of tariffs

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

- Contracted generation as of October 2017;
- The network model;
- Demand data provided under the Grid Code, which includes week 24 demand forecast data provided by the Distribution Network Operators (DNO), forecasts of demand at directly connected demand sites such as steelworks and railways and the effect of some embedded generation; and
- RPI (which increases the expansion constant).

Please note that demand data has not been updated in this October forecast, but will be updated in the December Draft Tariffs.

Table 11 – Contracted and modelled TEC

This was fixed based on the TEC register from October 2017.

(GW)	2017/18 Final	2018/19 Initial Forecast	2018/19 June Forecast	2018/19 Oct Forecast
Contracted TEC	72.2	79.6	78.8	82.4
Modelled Best View TEC	72.2	72.6	75.5	79.7

5.2. Adjustments for Interconnectors

When modelling flows on the transmission system, interconnectors 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 generation or demand charging bases.

Table 12 – Interconnectors

The table below reflects the contracted position of interconnectors in October 2017; there has been no change since the June draft forecast.

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
East - West	Deesside 400kV	Republic of Ireland	16	0	505	0
Moyle	Auchencrosh 275kV	Northern Ireland	10	0	80	0

5.3. RPI

The RPI index for the components detailed below is derived as the percentage increase of the average May – October RPI for 2017/18 compared to 2016/17.

Expansion Constant

The expansion constant has reduced marginally to £14.08481547 from £14.086345MWkm in the June tariffs, to reflect lower than previously forecast RPI. This has had a very small impact on tariffs in all zones, decreasing the stretch of the system circuit lengths and so decreasing the magnitude of locational tariffs, i.e. positive tariffs less positive and negative tariffs less negative.

Local substation and offshore substation tariffs

Local onshore substation tariffs are indexed by May - October RPI as are offshore local circuit tariffs, so have been updated from the June forecast to reflect latest forecast RPI for the period May 2017 – October 2017.

5.4. Allowed revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. By October, most TOs have undertaken annual regulatory reporting, and thus have provided National Grid with their indicative revenue forecast. Table 12 shows the forecast 2018/19 revenues that have been used in calculating the October tariffs.

The total forecasted revenue of Scottish Hydro Electricity Transmission revenue and Scottish Power Transmission) has reduced by £26m, mainly relating to the revised profile of spending and allowances, and the reduction in business rates following revaluation.

The OFTO revenue has reduced by £61m driven predominately by revised asset transfer dates.

National Grid Electricity Transmission revenue has reduced by £71.9m, reflecting the Correction factor (K) for over recoveries of revenue of £55m, and revised profile of spending and allowances.

Tariffs have therefore been calculated to recover £2,661.3m of revenue. This is a reduction of £158.5m from the June forecast of £2,819.8m.

Table 13 – Allowed revenues

£m Nominal		2017/18 TNUoS Revenue	2018/19 TNUoS Revenue					
		Jan 2017 Final	Feb 2017 Initial View	June 2017 Update	Oct 2017 Update	Dec 2017 Draft	Dec 2017 Draft	Jan 2018 Final
National Grid								
Price controlled revenue		1748.8	1727.8	1719.0	1647.1			
Less income from connections		41.9	41.9	41.9	41.9			
Income from TNUoS		1706.9	1685.9	1677.2	1605.2			
Scottish Power Transmission								
Price controlled revenue		333.7	390.5	377.7	360.5			
Less income from connections		12.8	26.8	14.0	14.2			
Income from TNUoS		321.0	363.8	363.8	346.3			
SHE Transmission								
Price controlled revenue		304.7	366.5	366.7	358.6			
Less income from connections		3.4	3.2	3.6	3.5			
Income from TNUoS		301.4	363.2	363.1	355.1			
Offshore		270.2	380.2	373.2	312.1			
Network Innovation Competition		32.1	40.5	40.5	40.5			
Transmission EDR				2	2			
Total to Collect from TNUoS		2631.5	2833.6	2819.8	2661.3			

5.5. Generation / Demand (G/D) Split

Apart from the revenue to be collected, the G/D split has not changed since the June tariff forecast.

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 2018/19 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2016. The value published is €1.16/£, which has remained the same since the June tariffs.

Generation Output

The forecast output of generation is aligned with Future Energy Scenario Generation output forecasts. Our forecast of 253TWh reflects our view of the total generation of generators that are liable for generation TNUoS charges during 2018/19, and has remained the same since the June tariffs. More information on generation forecast modelling is available in the FES publication from July 2017.[§§]

Error Margin

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

Table 14 – Generation and demand revenue proportions

		2017/18 Final	2018/19 Initial	2018/19 June	2018/19 Oct
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5
y	Error Margin	21%	21%	21%	21%
ER	Exchange Rate (€/£)	1.27	1.11	1.16	1.16
MAR	Total Revenue (£m)	2631.5	2833.5	2819.8	2661.3
GO	Generation Output (TWh)	251.0	239.9	252.6	252.6
G	% of revenue from generation	14.8%	15.1%	15.3%	16.2%
D	% of revenue from demand	85.2%	84.9%	84.7%	83.8%
G.R	Revenue recovered from generation (£m)	390.3	426.9	430.1	430.1
D.R	Revenue recovered from demand (£m)	2241.2	2406.6	2389.6	2231.2

5.6. Charging bases for 2018/19

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 forecast of gross system demand at Triad in Winter 2018/19 is 52GW. Our forecast of gross Half-Hour metered demand at triad is 19.8GW. The forecast of Embedded Generation Export triad volume is 6.5 GW The forecast of Non Half-Hour demand during 2018/19 is 24.2TWh. These numbers have been updated from the June tariff forecast using the revised demand forecasting methodology which has been developed under CMP 264/265.

Table 15 – Charging base

[§§] *http://fes.nationalgrid.com/*

Charging Bases	2017/18	2018/19 Initial	2018/19 June	2018/19 October	2018/19 Draft	2018/19 Final
Generation (GW)	67.6	66.8	69.7	75.0		
NHH Demand (4pm-7pm TWh)	25.3	23.7	24.2	24.2		
Net Charging						
Total Average Triad (GW)	47.7	46.4	46.0	45.9		
HH Demand Average Triad (GW)	13.2	14.3	13.2	13.3		
Gross Charging						
Total Average Triad (GW)	*Introduced by CMP264/265*			52.5		
HH Demand Average Triad (GW)				19.8		
Embedded Generation Export (GW)				6.5		

5.7. Annual Load Factors

The Annual Load Factors (ALFs) of each power station are required to calculate tariffs. For the purposes of this forecast we have used the final version of the 2018/19 ALFs, based upon data from 2012/13 - 2016/17, and were published on 19 October 2017 and are available from the National Grid website.[***] The Final ALFs for 2018/19 can be found in section 8.1.

5.8. Generation and Demand Residuals

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

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

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

Where

- R_G is the Generation residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from Generation
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from Generation locational zonal tariffs (£m)

*** http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_C is the TNUoS revenue recovered from onshore local circuit tariffs (£m)
- L_S is the TNUoS revenue recovered from onshore local substation tariffs (£m)
- B_G is the generator charging base (GW)

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

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

Where:

- R_D is the Gross Demand residual tariff (£/kW)
- D is the proportion of TNUoS revenue recovered from Demand
- R is the total TNUoS revenue to be recovered (£m)
- Z_D is the TNUoS revenue recovered from Demand locational zonal tariffs (£m)
- EE is the amount to be paid to Embedded Export Volumes through the Embedded Export Tariff (£m)
- B_D is the Demand charging base (Half-hour equivalent GW)

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

Table 16 - Residual Calculation

	Component	2017/18	2018/19 Initial	2018/19 June	2018/19 October
G	Proportion of revenue recovered from generation (%)	14.8%	15.1%	15.3%	16.2%
D	Proportion of revenue recovered from demand (%)	85.2%	84.9%	84.7%	83.8%
R	Total TNUoS revenue (£m)	2,631	2,833	2,820	2,661
Generation Residual					
R_G	Generator residual tariff (£/kW)	-1.85	-3.20	-3.28	-2.34
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	275.0	313.2	334.0	322.2
O	Revenue recovered from offshore local tariffs (£m)	208.5	293.9	288.4	244.0
L_G	Revenue recovered from onshore local substation tariffs (£m)	17.5	17.0	17.8	20.7
S_G	Revenue recovered from onshore local circuit tariffs (£m)	14.6	16.9	18.5	18.5
B_G	Generator charging base (GW)	67.6	66.8	69.7	75.0
Net Demand Residual					
R_D	Demand residual tariff (£/kW)	47.26	52.24	52.20	*no longer calculated*
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-12.4	-19.0	-12.0	
B_D	Demand Net charging base (GW)	47.7	46.4	46.0	
Gross Demand Residual					
R_D	Demand residual tariff (£/kW)	*Introduced by CMP264/265 to replace 'net residual'*			46.66
Z_D	Revenue recovered from the locational element of demand tariffs (£m)				-26.6
EE	Amount to be paid to Embedded Export Tariffs (£m)				189.9
B_D	Demand Gross charging base (GW)				52.5

5.9. Small Generators Discount

The small generators discount has been calculated as £ 11.079610/kW. This equates to a forecast of £30.6m which is recovered from suppliers through the HH and NHH tariffs.

5.10. Changes to the Small Generators Discount recovery following CMP264 and CMP265

The small generator discount calculation has changed following the move to gross charging for TNUoS Demand under CMP264/265. Following the introduction of the EET and HH demand being charged on a gross basis, the calculation of the Small Generators Discount will change.

The Small Generator Discount recovery is now taken from gross HH demand, and the residual used in the calculation of the discount is now the gross demand residual.

The rate charged to HH demand tariffs is now charged at a gross demand level instead of net.

Table 17 – Small Generators Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-2.34
Demand Residual (£/kW)	D	46.66
Small Generator Discount (£/kW)	T = (G + D)/4	11.08
Forecast Small Generator Volume (kW)	V	2,780,910
2017/18 SGD cost (£)	V x T	30,811,398
Prior year reconcilation (£)	R	- 236,300
Total SGD Cost (£)	C = (V x T) + R	30,575,098
Total Gross System Triad Demand (kW)	TD	52,463,074
Total HH Gross Triad Demand (kW)	HHD	19,801,167
Total NHH Consumption (kWh)	NHHD	24,172,250,677
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.58
Total Cost to HH Customers (£)	HHC = HHT * HHD	11,539,976
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.08
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	19,035,122

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 October tariffs on Friday 10 November from 10:30 to 11:30. If you wish to join the webinar, please contact us using the details below.

We always welcome questions and are happy to discuss specific aspects of the material contained in the October 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:

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

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Appendices

Appendix A: Changes and possible changes to the charging methodology affecting 2018/19 TNUoS Tariffs

Appendix B: Locational demand charges

Appendix C: Annual Load Factors

Appendix D: Contracted generation changes since the June forecast

Appendix E: Transmission Company Revenues

Appendix F: Generation Zones Map

Appendix G: Demand Zone Map

Appendix A: Changes and possible changes to the charging methodology affecting 2018/19 TNUoS Tariffs

This section focuses on specific CUSC modifications which may impact on the TNUoS tariff calculation methodology for 2018/19 onwards. All these modifications are subject to whether or not 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-use-system-code-cusc/modifications

A summary of the mods which could affect the 2018/19 tariffs and their status are listed below. More detail follows this table.

Table 18: Summary of CUSC modifications affecting 2018/19 TNUoS Tariffs

Mod Number	Description	Modification approved?	Status in the October 2017 Tariffs
251	**Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010**	No – The final modification report was submitted to Ofgem in October 2016.	**Not implemented.** Discussed in section 6.5 below
261	**Ensuring the TNUoS paid by Generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)**	No – the final report was submitted to Ofgem in June 2017.	**Not implemented.** Indicative recovery rates below
264	**Embedded Generation Triad Avoidance Standstill**	Yes – WACM 4 was approved by Ofgem	**Implemented** in Forecast. See below for information about Judicial Review.
265	**Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market**		
268	**Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits**	Yes – the original proposal was approved	**Implemented** in Forecast

Mod Number	Description	Modification approved?	Status in the October 2017 Tariffs
282	**The effect Negative Demand has on Zonal Locational Demand Tariffs**	No – expected Ofgem decision November 2017	**Not implemented.** Implemented as an example in section 6.4 below
283	**Consequential Changes to enable the Interconnector Cap and Floor regime**	No – The final report was published in October 2017.	**Not implemented.** Discussed in section 6.6 below

6.1. CMP264 and CMP265

Embedded Generation Triad Avoidance Standstill

and

Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market

The following update has been posted to Ofgem's website following the approval of the two modifications:

"UPDATE AS OF 23 OCTOBER 2017:

Ofgem has been served with a claim for judicial review concerning its decision to approve WACM4 of CUSC modifications CMP264 and CMP265.
The case number is: CO/4397/2017.

National Grid Electricity Transmission plc has been named by the claimants as an interested party to the proceedings.

Ofgem has filed its Acknowledgement of Service and Summary Grounds of Resistance for contesting the claim.

Any bodies that consider themselves interested parties should take their own legal advice in relation to this matter.

Ofgem's decision to approve WACM4 of CUSC modifications CMP264 and CMP265 stands unless quashed by the court." [†††]

In line with our licence and code obligations, National Grid's implementation activities in readiness for April 2018 will continue.

[†††] 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

6.3. CMP261

Ensuring the TNUoS paid by Generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3)

CMP261 seeks to ensure that the TNUoS paid by Generators in GB in Charging Year 2015/16 is in compliance with the €2.5/MWh annual average limit set in EU Regulation 838/2010 Part B (3).

CMP261 is currently with Ofgem for decision. If approved, CMP261 would see a rebate to generators of approximately £120m, with this value to be recovered from demand users in a future charging year.

The precise amount to be paid to generators, the repayment mechanisms, and the demand recovery mechanism are to be determined by Ofgem, as part of its decision. One option available to Ofgem is to not approve the modification, in which no payments and no recovery would be made.

Indicative Demand Rebate Levy Values

If the total rebate were to be approved as £120m, and if this were to be recovered from demand users in 2018/19, then an additional levy would be applied to each of the zonal tariffs published in Table 1. Indicative demand recovery rates would be:

- Gross HH Demand CMP261 Rebate Levy: 2.2873 £/kW
- NHH Demand CMP261 Rebate Levy: 0.3091 p/kWh

These values would apply to all demand tariffs in all zones. EETs are unaffected by CMP261.

These values are indicative only. Once a decision on the modification is received from Ofgem, National Grid will publish further details to the industry as required by the modification. Any additional recovery rates applicable to Gross HH and NHH demand volumes will be published as soon as practicable, and in future TNUoS forecasts.

6.4. CMP282

The effect Negative Demand has on Zonal Locational Demand Tariffs

This modification was raised by NGET to address possible distortions to demand tariffs that may occur when some demand nodes are net exporters of energy. Embedded generation connected at that location may cause some nodes to export energy. The current nodal demand calculation does not accommodate embedded exports well, and so may cause demand tariffs in that zone to increase by incorrectly reducing the chargeable demand base.

Likely implications of CMP282 on October 2017 TNUoS Tariff Forecast HH, NHH and Embedded Export Tariffs

This modification will correct the nodal demand calculation to take account of embedded generation connected to nodes in each demand zone. This will particularly affect demand zone 1 where there is a higher volume of embedded generation than the volume of demand.

Whereas currently there is a premium charged to HH and NHH demand triads, CMP282 will amend the calculation so that the gross demand base is used in the calculation. This will mean that the revenue to be collected from that zone will be spread over a greater volume of demand customers, and so the zonal tariff will reduce.

The EET in these zones will also decrease.

Table 19 – The impact of CMP282 on HH demand tariffs

The greatest impact of CMP 282 is on zone 1 tariffs where the HH tariff drops by £24.28. The residual increases by a small amount of £0.248.

		Gross HH Demand		
Zone	Zone Name	2018/19 October Forecast (£/kW)	2018/19 October CMP282 (£/kW)	Change (£/kW)
1	Northern Scotland	42.63	18.35	-24.275
2	Southern Scotland	25.07	25.13	0.061
3	Northern	36.70	36.92	0.229
4	North West	43.77	43.87	0.094
5	Yorkshire	43.58	43.83	0.248
6	N Wales & Mersey	45.19	45.43	0.248
7	East Midlands	47.14	47.39	0.248
8	Midlands	48.60	48.85	0.248
9	Eastern	49.12	49.37	0.248
10	South Wales	46.53	46.78	0.248
11	South East	52.27	52.52	0.248
12	London	54.59	54.84	0.248
13	Southern	53.55	53.80	0.248
14	South Western	53.61	53.86	0.248

Figure 5 – The impact of CMP282 on HH Demand Tariffs

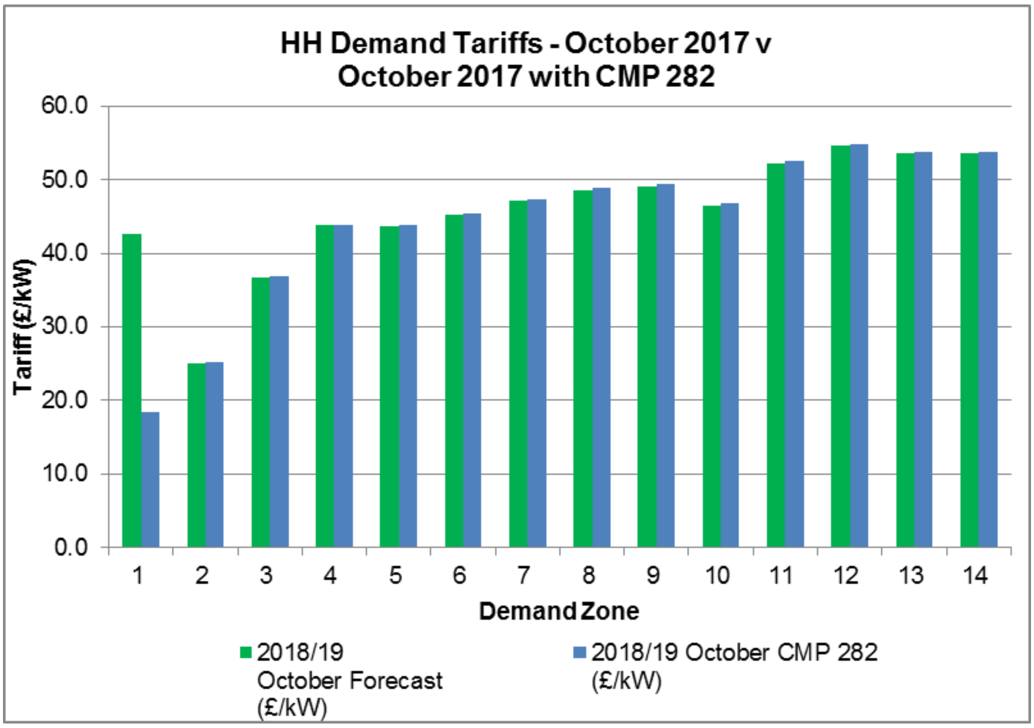


Table 20 – The impact of CMP 282 on NHH demand tariffs

Due to the increase in the HH charging base caused by the recalculation of nodal demand, zone 1 NHH tariffs also decrease significantly by over 55% to become the lowest.

Zone	Zone Name	2018/19 October Forecast (p/kWh)	2018/19 October CMP 282 (p/kWh)	Change (p/kWh)
1	Northern Scotland	5.69	2.45	-3.24
2	Southern Scotland	3.38	3.39	0.01
3	Northern	4.85	4.88	0.03
4	North West	5.88	5.89	0.01
5	Yorkshire	5.72	5.75	0.03
6	N Wales & Mersey	5.89	5.92	0.03
7	East Midlands	6.30	6.33	0.03
8	Midlands	6.71	6.74	0.03
9	Eastern	7.11	7.15	0.04
10	South Wales	5.64	5.67	0.03
11	South East	7.74	7.77	0.04
12	London	6.07	6.10	0.03
13	Southern	7.34	7.37	0.03
14	South Western	7.81	7.85	0.04

Figure 6 – The impact of CMP282 on NHH demand tariffs

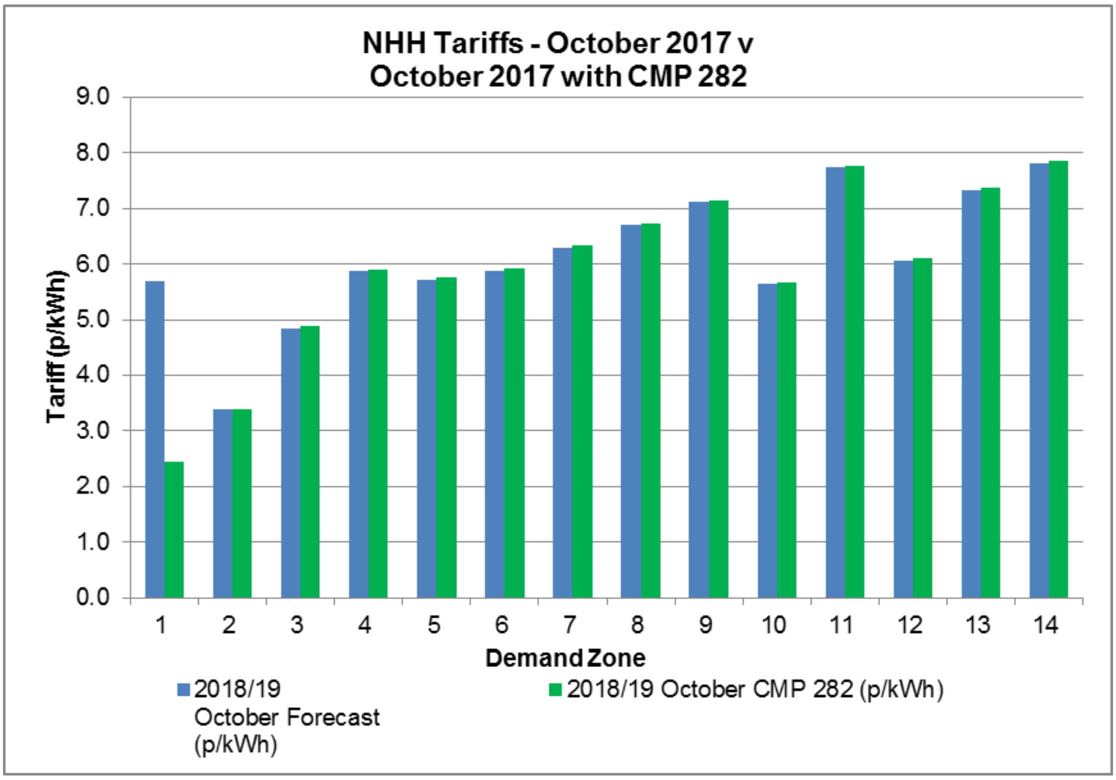
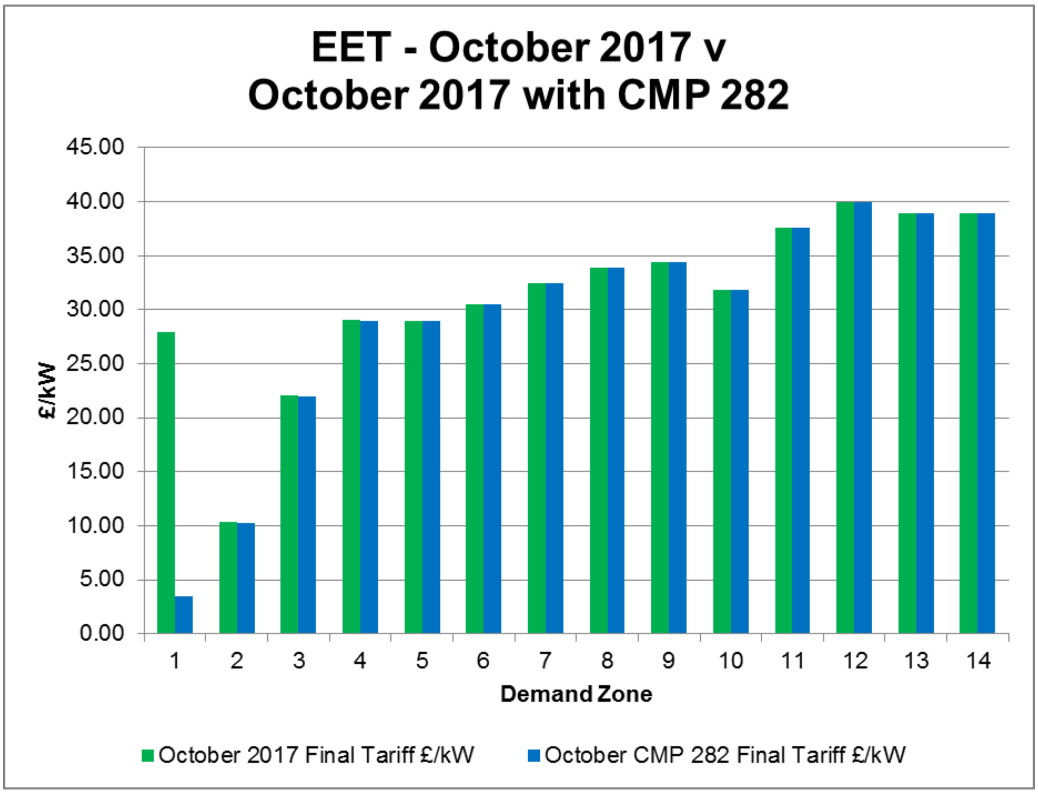


Table 21 – The impact of CMP282 on the EET

EETs are only affected in the zones where there are significant levels of embedded generation. Again, zone 1 sees the largest impact where the EET reduces by £24.52. There are minor reductions to zones 2, 3 and 4, and the remaining zones are unchanged.

Zone	October 2017 Final Tariff £/kW	October CMP 282 Final Tariff £/kW	Difference
1	27.96	3.44	-24.52
2	10.40	10.22	-0.19
3	22.03	22.01	-0.02
4	29.10	28.95	-0.15
5	28.92	28.92	0.00
6	30.52	30.52	0.00
7	32.47	32.47	0.00
8	33.93	33.93	0.00
9	34.45	34.45	0.00
10	31.87	31.87	0.00
11	37.60	37.60	0.00
12	39.92	39.92	0.00
13	38.88	38.88	0.00
14	38.94	38.94	0.00

Figure 7 – The impact of CMP282 on EETs



The final report was submitted to Ofgem in October 2017 and a decision is expected before the Draft Tariffs are published in December 2017.

We have included the functionality to switch on or off the CMP282 methodology in the October 2017 version of the DCLF ICRP Transport and Tariff Model.

To obtain a copy of the model, please see the Tools and Supporting Information section of this document.

6.5. CMP251

<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>

This modification seeks to remove the error margin from the G:D Split calculation. The post-charging year billing reconciliation process would recalculate the tariffs according to the €2.50/MWh limit imposed on generators by EU Regulation 838/2010, so that generator tariffs will charge exactly €2.50/MWh on average.

The final modification report was submitted to Ofgem in October 2017.

6.6. CMP283

<u>Consequential Changes to enable the Interconnector Cap and Floor regime</u>

CUSC needs to be updated to allow the provision of revenue data between interconnectors and NGET SO. This will allow the recovery and redistribution of revenue in accordance with the Cap and Floor regime. There are not expected to be any significant changes to revenue due to the interconnector Cap and Floor regime in 2018/19.

The final report was published in October 2017.

Appendix B: Locational demand charges

7.1. Locational demand charges

Table 22 – Demand profiles

The table below shows the latest demand forecast used in the October Tariff forecast.

There is no change to locational model demand profiles between the June and October tariffs.

Overall net peak demand has decreased from the June forecast from 46GW to 45.95GW.

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

		2018/19 June				2018/19 October				
Zone	Zone Name	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	NET Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	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	227	928	-530	0.74	227	1,477	489	0.74	1,001
2	Southern Scotland	2,820	2,999	662	1.69	2,820	3,500	1,259	1.66	670
3	Northern	2,508	2,241	526	1.21	2,508	2,664	1,078	1.20	581
4	North West	3,234	3,685	1,167	1.94	3,234	4,117	1,523	1.93	343
5	Yorkshire	4,347	3,395	1,007	1.76	4,347	3,920	1,610	1.76	635
6	N Wales & Mersey	2,831	2,281	594	1.23	2,831	2,678	1,085	1.22	538
7	East Midlands	5,333	4,228	1,376	2.15	5,333	4,763	1,878	2.16	477
8	Midlands	4,594	3,960	1,354	2.00	4,594	4,371	1,617	2.00	211
9	Eastern	5,843	5,829	1,429	3.07	5,843	6,605	2,133	3.09	624
10	South Wales	1,969	1,592	526	0.83	1,969	1,843	839	0.83	331
11	South East	3,355	3,579	838	1.92	3,355	3,999	1,169	1.91	318
12	London	5,271	3,918	2,068	1.82	5,271	4,323	2,286	1.84	149
13	Southern	5,668	5,014	1,617	2.56	5,668	5,584	2,072	2.56	437
14	South Western	2,609	2,355	554	1.27	2,609	2,621	764	1.27	200
Total		**50,609**	**46,004**	**13,187**	**24.20**	**50,609**	**52,463**	**19,801**	**24.17**	**6,516**

Appendix C: Annual Load Factors

8.1. ALFs

Table 19 lists the Annual Load Factors (ALFs) of generators expected to be liable for generator charges during 2018/19. 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 2018/19 also use the Generic ALF.

These ALFs have been updated since the June Tariffs.[‡‡‡]

Table 23: Specific Annual Load Factors

[‡‡‡] *The Final ALFs report for 2018-19 can be found here:*
http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	
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%	30.9623%	33.2126%
BHLARAIDH	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4339%	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%	26.9703%
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%	22.5645%	30.4133%
CORRIEMOILLIE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.2316%	33.6357%
CORYTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	15.6869%	9.7852%	17.5123%	26.4000%	63.0383%	19.8664%
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%	38.3247%	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%

Power Station	Technology	Yearly Load Factor Source 2012	2013	2014	2015	2016	Yearly Load Factor Value 2012	2013	2014	2015	2016	Specific ALF
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%	35.8823%
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%	40.0283%	63.5383%
ERROCHTY	Hydro	Actual	Actual	Actual	Actual	Actual	14.5869%	28.2628%	25.3585%	28.1507%	16.1775%	23.2289%
EWE HILL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.3314%	34.0023%
FALLAGO	Onshore_Wind	Partial	Actual	Actual	Actual	Actual	32.9869%	54.8683%	44.7267%	55.7992%	43.2176%	51.7981%
FARR WINDFARM TOMATIN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	34.0149%	44.7212%	38.5712%	40.9963%	34.1766%	37.9147%
FASNAKYLE G1 & G3	Hydro	Actual	Actual	Actual	Actual	Actual	22.1176%	35.3695%	57.4834%	53.1573%	30.9768%	39.8345%
FAWLEY CHP	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	61.1362%	63.3619%	72.8484%	57.6978%	63.2006%	62.5662%
FFESTINIOGG	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	2.9286%	5.4631%	4.3251%	3.4113%	5.6749%	4.3999%
FIDDLERS FERRY	Coal	Actual	Actual	Actual	Actual	Actual	61.6386%	49.0374%	45.2435%	27.4591%	8.2478%	40.5800%
FINLARIG	Hydro	Actual	Actual	Actual	Actual	Actual	40.2952%	59.9142%	59.4092%	65.1349%	49.6402%	56.3212%
FOYERS	Pumped_Storage	Actual	Actual	Actual	Actual	Actual	13.4800%	14.7097%	12.3048%	15.4323%	11.3046%	13.4982%
FREASDAIL	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	32.5600%	33.7452%
GALAWHISTLE	Onshore_Wind	Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	34.9765%	34.5507%
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%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	
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%	22.2449%	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%	31.3165%
KILLIN CASCADE	Hydro	Actual	Actual	Actual	Actual	Actual	32.3429%	45.5356%	44.8205%	53.2348%	27.4962%	40.8997%
KINGS LYNN A	CCGT_CHP	Actual	Actual	Actual	Generic	Generic	0.0003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0001%
LANGAGE	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	41.9115%	40.8749%	34.8629%	16.5310%	44.5413%	39.2164%
LINCS WIND FARM	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	20.3244%	46.5987%	43.8178%	49.1306%	44.5192%	46.7495%
LITTLE BARFORD	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	16.3807%	33.6286%	49.6644%	39.9829%	64.8597%	41.0920%
LOCHLUICHART	Onshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	24.9397%	20.2103%	29.2663%	31.6897%	27.0554%
LONDON ARRAY	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	38.9520%	51.2703%	64.0880%	66.8682%	53.6245%	61.5269%
LYNEMOUTH	Coal	Generic	Generic	Generic	Partial	Generic	0.0000%	0.0000%	0.0000%	68.0196%	0.0000%	59.0584%
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%	31.8734%
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%

Power Station	Technology	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
		2012	2013	2014	2015	2016	2012	2013	2014	2015	2016	
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%
TODDLEBURN	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	32.7175%	39.5374%	33.7211%	35.0823%	31.3435%	33.8403%
TORNESS	Nuclear	Actual	Actual	Actual	Actual	Actual	84.8669%	86.4669%	91.4945%	85.7725%	97.9942%	87.9113%
USKMOUTH	Coal	Actual	Actual	Partial	Actual	Actual	45.1938%	38.9899%	46.9428%	25.5184%	24.3304%	36.5674%
WALNEY I	Offshore_Wind	Actual	Actual	Actual	Actual	Actual	44.2799%	57.7046%	52.0555%	50.7535%	47.4617%	50.0902%
WALNEY II	Offshore_Wind	Partial	Actual	Actual	Actual	Actual	54.7907%	61.9219%	58.2355%	35.7988%	54.9727%	58.3767%
WEST BURTON B	CCGT_CHP	Partial	Actual	Actual	Actual	Actual	21.3299%	30.3021%	46.8421%	59.3477%	54.2878%	53.4925%
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind	Generic	Partial	Actual	Actual	Actual	0.0000%	40.4447%	40.0506%	48.7540%	48.7691%	45.8579%
WESTERMOST ROUGH	Offshore_Wind	Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	26.2900%	54.8014%	58.1061%	46.3992%
WHITELEE	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	28.2265%	35.1074%	29.8105%	31.8773%	27.2893%	29.9714%
WHITELEE EXTENSION	Onshore_Wind	Actual	Actual	Actual	Actual	Actual	12.4146%	27.0102%	27.7787%	26.7655%	23.5253%	25.7670%
WILTON	CCGT_CHP	Actual	Actual	Actual	Actual	Actual	3.4258%	4.4941%	21.5867%	16.1379%	14.4130%	11.6817%

Table 24: Generic Annual Load Factors

Technology	Generic ALF
Gas_Oil	0.1890%
Pumped_Storage	10.4412%
Tidal	18.9000%
Biomass	26.8847%
Wave	31.0000%
Onshore_Wind	34.3377%
CCGT_CHP	43.2127%
Hydro	41.3656%
Offshore_Wind	49.5051%
Coal	54.5778%
Nuclear	76.4001%

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

The Biomass ALF for 2016/17 has been copied from the 2015/16 year due to there not being any single majority biomass-fired stations operating over that period.

Appendix D: Contracted generation changes since the June forecast

Table 21 shows the TEC changes notified between June 2017 (used as the basis for the initial forecast) and October 2017. Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table. The tariffs in this forecast are based on National Grid's best view and therefore may include different generation to that shown below.

Table 25: Generation Contracted TEC Changes

Power Station	Node	MW Change	Generation Zone
Aikengall II Windfarm	WDOD10	140.00	11
Eggborough	EGGB40	1870.00	15
Galloper Wind Farm	LEIS10	-86.00	18
Loganhead Windfarm	EWEH1Q	36.00	12
Margree	MARG10	-43.00	10
Pencloe Windfarm	BLAC10	-63.00	10
Peterhead	PEHE20	1180.00	2
Powersite @ Drakelow	DRAK40	380.00	18
Race Bank Wind Farm	WALP40_EME	160.00	17
Spalding Energy Expansion	SPLN40	300.00	17
Sutton Bridge	WALP40_EME	31.00	17
Tees Renewable Energy Plant	GRSA20	-285.00	13
West Burton B	WBUR40	-38.00	16
West Burton Energy Storage	WBUR40	38.00	16

Appendix E: Transmission Company Revenues

9.1. National Grid Revenue Forecast

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

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

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

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

Network Innovation Competition 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			26/10/2017					Notes
			Licence Term		Yr t+1			
Regulatory Year			2014/15	2015/16	2016/17	2017/18	2018/19	
Actual RPI					264.99			April to March average
RPI Actual		RPIAt			1.228			Office of National Statistics
Assumed Interest Rate		It	0.50%	0.70%	0.34%	0.29%	0.38%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1443.83	1475.59	1571.39	1554.94	1587.63	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.50	-114.40	-185.40	-253.30	-311.00	Forecast
RPI True Up	A3	TRUt	-0.53	4.70	-19.92	-31.40	-6.08	Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	0.03	0.03	0.01	0.02	0.04	HM Treasury Forecast
Current Calendar Year RPI Forecast		GRPIFc	0.03	0.02	0.02	0.04	0.04	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	0.03	0.03	0.03	0.03	0.03	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.21	1.23	1.23	1.27	1.31	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.7**	**1675.5**	**1684.4**	**1614.5**	**1669.5**	
Pass-Through Business Rates	B1	RBt		1.2	1.5	2.7	1.6	Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	0.0	0.0	Forecast
Licence Fee	B3	LFt		2.0	2.7	3.2	-0.4	Forecast
Inter TSO Compensation	B4	ITCt		3.8	2.7	0.5	1.3	Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.00	0.00	0.00	0.00	0.00	Forecast
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	321.0	346.3	Forecast
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	301.4	355.1	Forecast
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	270.2	312.1	Forecast
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.5	0.6	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.1**	**890.0**	**885.9**	**899.4**	**1016.6**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	4.1	Forecast
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.6	7.6	Forecast
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	2.6	1.4	Forecast
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	0.0	0.0	Forecast
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0**	**13.9**	**18.7**	**15.3**	**13.1**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.2	10.5	Forecast
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	32.1	40.5	Forecast
Future Environmental Discretionary Rewards	F	EDRt			0.0	0.0	2.0	Forecast
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	0.0	0.0	Forecast
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	6.1	6.3	Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	-1.1	0.0	Forecast
Correction Factor	K	-Kt		56.4	104.0	97.0	-55.4	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2751.3**	**2673.4**	**2703.2**	
Termination Charges	B5		0	0	0	0	0	
Pre-vesting connection charges	P		47.0	45.0	42.7	41.9	41.9	Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2631.5**	**2661.3**	
Final Collected Revenue	U	TNRt	2477.3	2636.7	2708.7	2631.5	2661.3	Forecast
Forecast percentage change to Maximum Revenue M				6.2%	2.6%	-2.8%	1.1%	
Forecast percentage change to TNUoS Collected Revenue T				6.4%	2.7%	-2.8%	1.1%	

9.2. Scottish Power Transmission Revenue Forecast

Under the relevant STC (System Operator Transmission Owner Code) procedures, the Scottish Power Transmission revenue forecast will be updated in November and finalised by 25 January 2018. The indicative SPT revenue to be collected via TNUoS for 2018/19 is £346.3m.

9.3. SHE Transmission Revenue Forecast

Under the relevant STC (System Operator Transmission Owner Code) procedures, the Scottish Hydro Electric Transmission (SHE Transmission) revenue forecast will be updated in November and finalised by 25 January 2018. The indicative SHET Transmission revenue to be collected via TNUoS for 2018/19 is £355.1m.

9.4. Offshore Transmission Owner Revenues

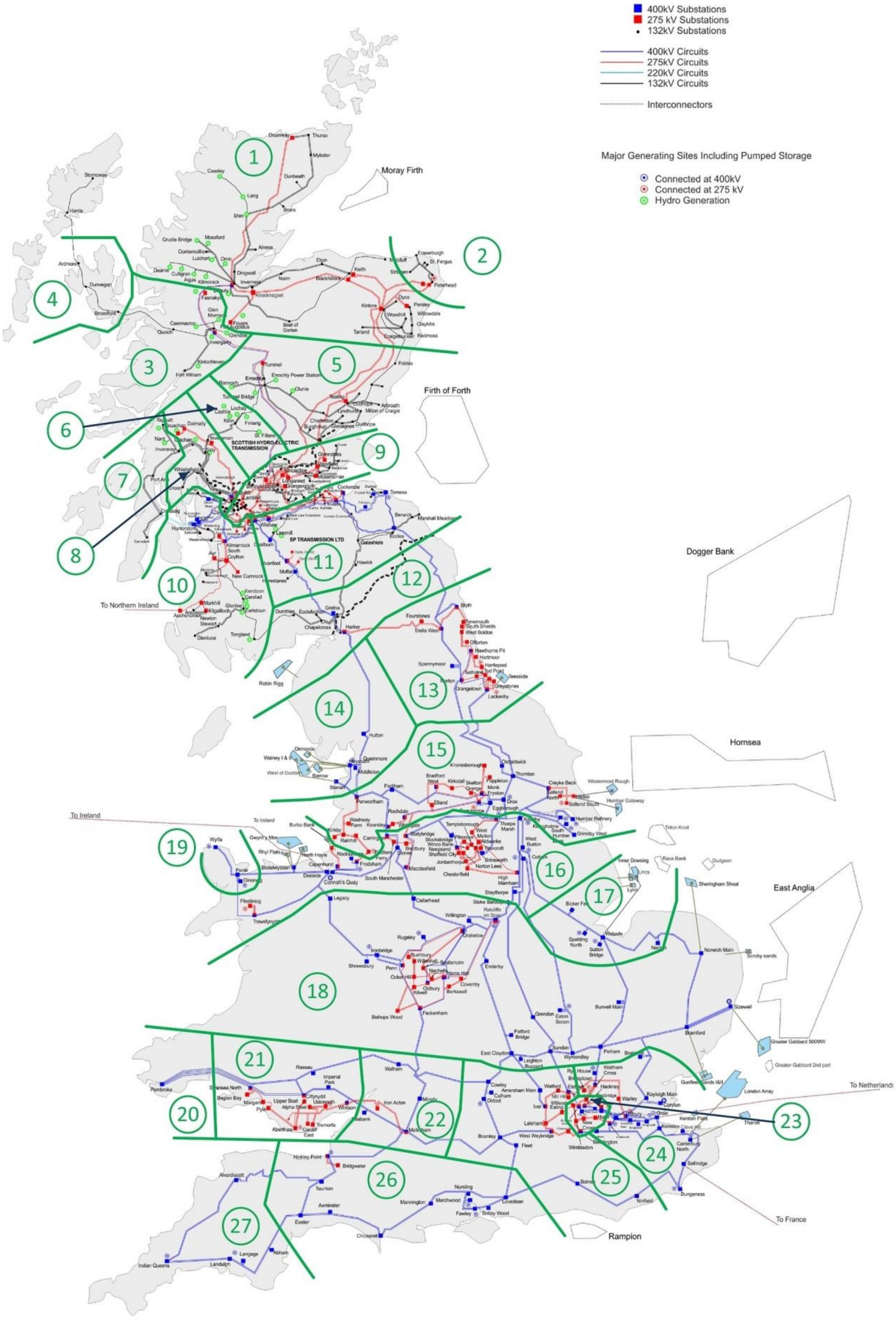
Under the relevant STC (System Operator Transmission Owner Code) procedures, OFTO revenue will be updated in November and finalised by 25 January 2018. The indicative total OFTO revenue to be collected via TNUoS for 2018/19 is £ 312.1m

Table 27 - Offshore Transmission Owner revenues (indicative)

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="5">26/10/2017</th><th></th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th><th>2017/18</th><th>2018/19</th><th>Notes</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</td><td>6.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>7.4</td><td>7.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td>13.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.4</td><td>8.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>12.5</td><td>12.3</td><td>14.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td>20.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.2</td><td>12.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td>28.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.5</td><td>39.5</td><td>40.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>19.5</td><td>18.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.7</td><td>27.2</td><td>26.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>29.3</td><td>28.2</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>22.0</td><td>22.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>0.0</td><td rowspan="2">29.3</td><td>9.7</td><td>11.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>0.0</td><td>11.6</td><td>13.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2018/19</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>40.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2019/20</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2020/21</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2021/22</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>0.0</td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>260.8</td><td>265.5</td><td>312.1</td><td></td></tr>
</table>

Appendix F: Generation zones map

Figure A2: GB Existing Transmission System



Appendix G: Demand zones map