Tariff Information Paper

Final TNUoS tariffs for 2017/18

This information paper provides National Grid's Final Transmission Network Use of System (TNUoS) tariffs for 2017/18, applicable to Generators and Suppliers, effective from 01 April 2017.

31 January 2017

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1 Executive Summary

This document contains the Final Transmission Network Use of System (TNUoS) tariffs for 2017/18, which will become effective on 1 April 2017. TNUoS charges are paid by generators and suppliers for use of the GB Transmission networks.

Total Transmission Owner (TO) allowed revenue to be recovered from TNUoS charges will be £2,631.5m in 2017/18, a decrease of £77.2m from 2016/17. Generation tariffs have been set to recover £390.3m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. This is a £63.1m reduction in generation revenue compared to last year, reflecting reductions in forecast generation output and the Euro exchange rate, and results in an average decrease of £1.44/kW in generation tariffs from 2016/17. Demand tariffs have therefore been set to recover £2,241.23m of revenue, a decrease of £14m from 2016/17. This reflects the above reduction in overall revenue for GB Transmission Owners.

During 2016/17 National Grid has been further improving its demand forecasting capability to model not only the significant increase in distributed generation in recent years, but also the significant potential variability. Consequently, we are forecasting average triad demand of 47.7GW, average Half-Hour (HH) triad demand of 13.2GW and Non-Half-Hour (NHH) demand of 25.3TWh. These numbers have not changed from our Draft tariff forecast published in December 2016.

These chargeable demand numbers and updated TO revenues mean that the average HH demand tariff has increased by £3.33/kW and the average NHH demand tariff has decreased by 0.04p/kWh compared to 2016/17.

Changes to the Final tariffs in relation to our Draft tariff forecast have predominantly been influenced by updates to TO revenue inputs to the charging models. TO revenues have been updated based on the final revenue submissions from each of the onshore and offshore TOs, which has decreased the total TO revenue input by £34.5m since the Draft tariffs.

We have also made some very minor changes to the Annual Load Factors for generation, in accordance with the CUSC Charging Methodology[*]. These reflect the final Annual Load Factors that were published on our website on 25 January 2017 which take into account comments from generators on the draft Annual Load Factors published in December 2016.

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 from our June forecast at 21%.

Please note that this tariff forecast has been undertaken in accordance with the current CUSC charging methodology and therefore no current charging modifications are taken into account in these tariffs. We recognise however that there are a number of ongoing modifications which

[*] Please see paragraph 14.15.100 onwards for information within the Charging Methodology on Annual Load Factors (ALFs).

could impact tariffs but unless a mid-year tariff change process is initiated these are very unlikely to impact 2017/18 tariffs. More details on ongoing charging modifications can be found on the National Grid website[†].

We welcome feedback on any aspect of this document and related 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 or if you have any questions on this document. Given that there has been little change to the assumptions used to calculate these Final tariffs since our Draft tariff forecast, we are minded not to hold a tariff webinar on this occasion but please let us know if you would still welcome a webinar session.

[†] Please find further information here: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

2 Final 2017/18 Tariffs Summary

This section summarises the Final generation and demand tariffs for 2017/18. Information can be found in later sections on how these tariffs were calculated and how they have changed from the 2016/17 tariffs.

2.1 Final Generation Tariffs 2017/18

Table 1 - Wider Generation Tariffs

Under the Transmit methodology[‡] each generator has its own load factor as listed in Appendix C. The 80% and 40% loads factors used in this table are only for illustration.

Zone	Zone Name	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Residual Tariff (£/kW)	Conventional 80% Tariff (£/kW)	Intermittent 40% Tariff (£/kW)
1	North Scotland	-0.002000	11.940060	16.909972	-1.853883	24.606137	19.832113
2	East Aberdeenshire	0.794338	5.576753	16.909972	-1.853883	20.311829	17.286790
3	Western Highlands	-0.408343	10.088312	16.676506	-1.853883	22.484930	18.857948
4	Skye and Lochalsh	-6.224181	10.088312	16.419588	-1.853883	16.412174	18.601030
5	Eastern Grampian and Tayside	0.273013	8.954210	16.107179	-1.853883	21.689678	17.834980
6	Central Grampian	2.437359	10.092599	17.127997	-1.853883	25.785552	19.311153
7	Argyll	1.556747	8.028893	25.544208	-1.853883	31.670187	26.901883
8	The Trossachs	1.784393	8.028893	15.183823	-1.853883	21.537448	16.541498
9	Stirlingshire and Fife	-0.133834	3.913693	13.153459	-1.853883	14.296696	12.865053
10	South West Scotlands	1.695579	6.348284	14.148463	-1.853883	19.068786	14.833893
11	Lothian and Borders	2.818959	6.348284	9.032482	-1.853883	15.076184	9.717912
12	Solway and Cheviot	0.568031	3.496664	7.670008	-1.853883	9.181488	7.214791
13	North East England	3.144168	2.042519	4.198748	-1.853883	7.123047	3.161872
14	North Lancashire and The Lakes	1.202446	2.042519	3.009858	-1.853883	3.992436	1.972983
15	South Lancashire, Yorkshire and Humber	3.997792	0.568225	0.164386	-1.853883	2.762875	-1.462207
16	North Midlands and North Wales	3.745536	-0.951028		-1.853883	1.130831	-2.234294
17	South Lincolnshire and North Norfolk	2.193746	-0.335202		-1.853883	0.071702	-1.987964
18	Mid Wales and The Midlands	1.229614	-0.198633		-1.853883	-0.783175	-1.933336
19	Anglesey and Snowdon	4.415405	-1.704058		-1.853883	1.198276	-2.535506
20	Pembrokeshire	9.048900	-3.884439		-1.853883	4.087465	-3.407659
21	South Wales & Gloucester	6.153082	-3.944204		-1.853883	1.143835	-3.431565
22	Cotswold	3.146674	2.065177	-6.056186	-1.853883	-3.111254	-7.083998
23	Central London	-4.269553	2.065177	-5.486685	-1.853883	-9.957979	-6.514497
24	Essex and Kent	-3.668247	2.065177		-1.853883	-3.869988	-1.027812
25	Oxfordshire, Surrey and Sussex	-1.153480	-2.668629		-1.853883	-5.142266	-2.921334
26	Somerset and Wessex	-1.243261	-3.921646		-1.853883	-6.234461	-3.422541
27	West Devon and Cornwall	0.195665	-5.301776		-1.853883	-5.899638	-3.974593
		Small Generation Discount (£/kW)			11.351718		

[‡] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.184663	0.105639	0.076115
<1320 MW	Redundancy	0.406797	0.251688	0.183048
>=1320 MW	No redundancy		0.331225	0.239543
>=1320 MW	Redundancy		0.543787	0.396919

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.939872	Dinorwig	2.206750	Kilmorack	0.181645
Aigas	0.601544	Dunlaw Extension	1.379173	Langage	0.604792
An Suidhe	2.819601	Brochlock	1.317382	Lochay	0.336577
Arecleoch	1.910276	Dumnaglass	1.707609	Luichart	0.527938
Baglan Bay	0.699507	Edinbane	-6.291543	Mark Hill	0.805306
Beinneun Wind Farm	1.381894	Earlshaugh Wind Farm	3.464522	Margree	5.537474
Bhlaraidh Wind Farm	0.593841	Ewe Hill	1.263917	Marchwood	0.351279
Black Hill	0.793539	Farr Windfarm	2.065880	Millennium Wind	1.680242
BlackCraig Wind Farm	5.789906	Fallago	0.905483	Moffat	0.155042
Black Law	1.607155	Carraig Gheal	4.045828	Mossford	2.648705
BlackLaw Extension	3.408181	Ffestiniogg	0.232696	Nant	2.308346
Bodelwyddan	0.105826	Finlarig	0.294505	Necton	1.034410
Carrington	-0.032882	Foyers	0.692563	Rhigos	0.093347
Clyde (North)	0.100867	Galawhistle	0.778413	Rocksavage	0.016271
Clyde (South)	0.116647	Glendoe	1.691813	Saltend	0.313585
Corriegarth	3.466566	Ulziside	8.931637	South Humber Bank	0.867492
Corriemoillie	1.530696	Gordonbush	0.376037	Spalding	0.255407
Coryton	0.047815	Griffin Wind	-0.845619	Kilbraur	0.237471
Cruachan	1.676790	Hadyard Hill	2.545783	Stronelairg	1.332406
Crystal Rig	0.334929	Harestanes	2.304928	Strathy Wind	2.018352
Culligran	1.594105	Hartlepool	0.552782	Wester Dodds	0.647899
Deanie	2.618888	Hedon	0.166412	Whitelee	0.097613
Dersalloch	2.215514	Invergarry	1.305184	Whitelee Extension	0.271364
Didcot	0.476938	Kilgallioch	0.967994		

More details on local circuit changes can be found in section 5.2 below.

Table 4 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.441339	38.933077	0.966762
Greater Gabbard	13.951635	32.059484	0.000000
Gunfleet	16.104666	14.785345	2.763466
Gwynt Y Mor	16.990859	16.738095	0.000000
Lincs	13.906629	54.447630	0.000000
London Array	9.466607	32.242737	0.000000
Ormonde	23.004623	42.855458	0.341522
Robin Rigg East	-0.425554	28.189344	8.737175
Robin Rigg West	-0.425554	28.189344	8.737175
Sheringham Shoal	22.226453	26.066423	0.566607
Thanet	16.926252	31.539657	0.759271
Walney 1	19.854080	39.539350	0.000000
Walney 2	19.709687	39.887693	0.000000
West of Duddon Sands	7.661147	37.803015	0.000000
Westermost Rough	16.131802	27.288105	0.000000
Humber Gateway	13.520839	30.507520	0.000000

2.2 Final Demand Tariffs 2017/18

Table 5 - Demand Tariffs

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

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	29.577679	6.215608
2	Southern Scotland	30.480981	4.262747
3	Northern	39.223189	5.943493
4	North West	45.245665	5.878185
5	Yorkshire	44.967107	5.978783
6	N Wales & Mersey	46.791119	6.607274
7	East Midlands	47.889103	6.248796
8	Midlands	49.457444	6.426317
9	Eastern	49.617070	7.095134
10	South Wales	45.551887	5.775370
11	South East	52.537577	7.475220
12	London	54.969649	5.487378
13	Southern	53.405080	7.047920
14	South Western	51.955583	7.464813

These tariffs include a small generators discount revenue recovery of £0.552245/kW and 0.0751737p/kWh.

3 Introduction

3.1 Background

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.

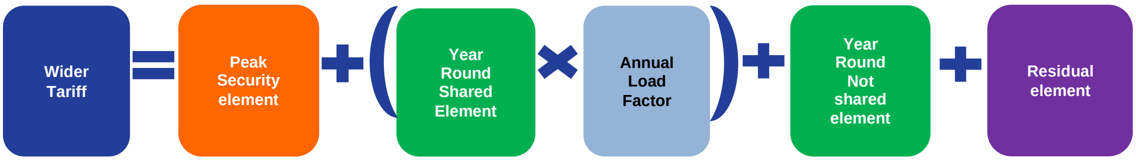
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational “residual” tariff elements are included in the generation and 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.

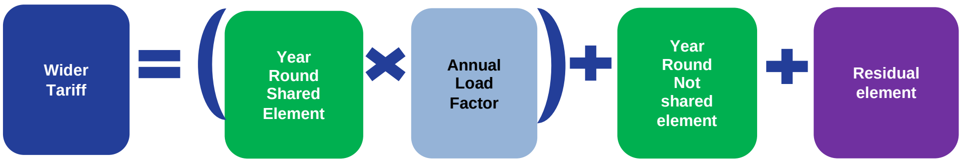
3.2 Charging Principles

Under the current methodology there are 27 generation zones, and each zone has four tariffs. A generator’s liability is dependent upon its type of generation. Coal, Nuclear, Gas, Pumped Storage, Peaking and Hydro are classed as conventional and wind is intermittent. Liability for each tariff component is shown below:

Conventional Generator **(Coal, Nuclear, Gas, Pumped Storage, Peaking and Hydro)**



Intermittent Generator (wind)



Each generator has a specific Annual Load Factor based on its performance over the last five years. Where new plant does not have at least three complete charging year's history then generic load factors specific to the technology are also used. The Annual Load Factors used in the Final tariffs are listed in Appendix C.

3.3 P272

Balancing and Settlement Code amendment P272 makes it mandatory that Non-Half-Hour (NHH) profile classes 5-8 move to metering classes E, F and G Half-Hour (HH) settlement. The subsequent amendment P322 revised the completion date for P272 to 1 April 2017, so P272 will take full effect in 2017/18.

4 Updates to the Charging Model for 2017/18

Since the Draft tariffs were published in December we have updated allowed revenue using final revenue submissions from onshore and offshore Transmission Owners, made adjustments to Annual Load Factors and corrected an error in October actual RPI (with relation to expansion constant and local substation tariffs).

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

4.1 Changes affecting the locational element of tariffs

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

- Contracted generation as at 31 October 2016;
- 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).

These inputs would have all remained unchanged since the Draft tariffs, however an error was found in the actual RPI for October. This has changed the expansion factor from £13.575354/MWkm to £13.57449607/MWkm.

Table 6 - Contracted and Modelled TEC

This was fixed based on the TEC register as at 31 October 2016, so no changes have been made since the Draft tariff forecast.

(GW)	2016/17	2017/18 Initial forecast	2017/18 June Forecast	2017/18 Oct Forecast	2017/18 Draft Tariffs	2017/18 Final Tariffs
Contracted TEC	69.9	73.4	73.1	72.2	72.2	72.2
Modelled Best ViewTEC	69.9	71.1	73.8	72.5	72.2	72.2

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4.1.1 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 (see Table 7).

Table 7 – Interconnectors

The table below reflects the contracted position of interconnectors on 31 October 2016 and thus there has been no change since the 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

4.1.2 RPI

The RPI index for the components detailed below is derived as the percentage increase of the average May – October RPI for 2016/17 compared to 2015/16.

Expansion Constant

The expansion constant has decreased to £13.57449607MWkm from £13.575354/MWkm in the Draft tariffs, to reflect marginally lower actual 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. The RPI has been reflected in the tariffs.

4.2 Changes affecting the residual element of tariffs

4.2.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs & OFTOs) in Great Britain. Table 8 shows the forecast 2017/18 revenues that have been used in calculating the Final tariffs.

The Scottish Hydro Electricity Transmission revenue has decreased by £25.8m following final submission of revenue information in January. Whilst we were not privy to the detail, it is known that this is predominantly due to correction of an error in how connection charges are reported. Scottish Power Transmission revenue has decreased by £0.9m since the Draft forecast.

The OFTO revenue has reduced by £4m due to updates provided in the final revenue submissions by OFTOs. This is mainly due to increases to RPI and refunds for tender fees.

National Grid Electricity Transmission revenue has increased by £5m. The revenue recovered in 15/16 has reduced and hence increased through the licence ‘K’ factor the NGET revenue for 17/18.

Ofgem published its funding decision on the 2016 Network Innovation Competition which awards £33.1m to four projects.[§] This has since been amended by Ofgem to £32.1m following the decision that previously awarded money should be refunded.

Tariffs have therefore been calculated to recover £2,631.5m of revenue. This is a reduction of £34.5m from the December Draft forecast of £2,666.0m. This update is based on TO submissions of revenue requirements to NGSO by 25 January 2017, on which they are invoiced.

Table 8 – Allowed Revenues

£m Nominal Value	2016/17 TNUoS Revenue	2017/18 TNUoS Revenue				
	Jan 2016 Final	Feb 2016 Initial View	June 2016 Update	Oct 2016 Update	Dec 2016 Draft	Jan 2017 Final
National Grid						
Price controlled revenue	*1,828.2*	*1,806.4*	*1,811.2*	*1,750.4*	*1,753.4*	*1,748.8*
Less income from connections	*42.7*	*46.5*	*46.5*	*44.1*	*44.0*	*41.9*
Income from TNUoS	**1,785.5**	**1,760.0**	**1,764.7**	**1,706.3**	**1,709.5**	**1,706.9**
Scottish Power Transmission						
Price controlled revenue	*306.4*	*347.1*	*341.0*	*327.7*	*333.5*	*333.7*
Less income from connections	*11.8*	*13.9*	*14.0*	*11.4*	*11.4*	*12.8*
Income from TNUoS	**294.6**	**333.1**	**327.0**	**316.3**	**322.1**	**321.0**
SHE Transmission						
Price controlled revenue	*326.2*	*328.5*	*327.3*	*305.8*	*312.6*	*304.7*
Less income from connections	*3.4*	*3.6*	*3.6*	*(13.6)*	*(14.6)*	*3.4*
Income from TNUoS	**322.8**	**324.9**	**323.7**	**319.4**	**327.2**	**301.4**
Offshore	**260.8**	**276.5**	**279.2**	**293.0**	**274.1**	**270.2**
Network Innovation Competition	**44.9**	**40.5**	**40.5**	**40.5**	**33.1**	**32.1**
Total to Collect from TNUoS	**2,708.7**	**2,735.0**	**2,735.1**	**2,675.6**	**2,666.0**	**2,631.5**

4.2.2 Demand: Generation Split

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

[§] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition

As prescribed by the Use of System charging methodology, the exchange rate for 2017/18 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2016. The value published is €1.27/£, which has not changed since the Draft tariffs.

Generation Output

The forecast output of generation is aligned with Future Energy Scenario Generation output forecasts. Our forecast of 251TWh reflects our view of the total generation of generators that are liable for generation TNUoS charges during 2017/18, and has not changed since the Draft tariffs.

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 in Table 9.

Table 9 - Generation and Demand revenue proportions

		2016/17	2017/18 Initial	2017/18 June	2017/18 Oct	2017/18 Draft	2017/18 Final
CAPEC	Limit on generation tariff (€/MWh)	2.5	2.5	2.5	2.5	2.5	2.5
y	Error Margin	8.2%	8.2%	21%	21%	21%	21%
ER	Exchange Rate (€/£)	1.36	1.34	1.27	1.27	1.27	1.27
MAR	Total Revenue (£m)	2,709	2,735	2,735	2,676	2,666	2,631
GO	Generation Output (TWh)	269	263	251	251	251	251
G	% of revenue from generation	16.7%	16.4%	14.3%	14.6%	14.6%	14.8%
D	% of revenue from demand	83.3%	83.6%	85.7%	85.4%	85.4%	85.2%
G.R	Revenue recovered from generation (£m)	453	450	390	390	390	390
D.R	Revenue recovered from demand (£m)	2,255	2,285	2,345	2,285	2,276	2,241

4.2.3 Charging bases for 2017/18

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 system demand at Triad in Winter 2017/18 is 47.7GW. Our forecast of Half-Hour metered demand at triad is 13.2GW. The forecast of Non Half-Hour demand during 2017/18 is 25.3TWh. These numbers remain unchanged from the Draft tariff forecast in December.

Table 10 - Charging Base

Charging Base	2016/17	2017/18 Initial	2017/18 June	2017/18 Oct	2017/18 Draft	2017/18 Final
Generation (GW)	62.9	67.3	67.0	66.6	67.6	67.6
Total Average Triad (GW)	49.8	49.3	49.1	49.1	47.7	47.7
HH Demand Average Triad (GW)	13.1	16.3	16.4	16.4	13.2	13.2
NHH Demand (4pm-7pm TWh)	26.1	23.1	23.6	23.6	25.3	25.3

4.2.4 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 new ALFs, which have only seen minor changes since the Draft tariffs. The final ALFs applicable to 2017/18 tariffs, based upon data from 2011/12 - 2015/16, were published on 25 January 2017 and are available from the National Grid website.[**]

4.2.5 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

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

The Demand Residual = (Total demand revenue less revenue recovered from locational demand tariffs) divided by total system triad demand

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

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

Where:

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

$\mathbf{Z_G}$, $\mathbf{Z_D}$ and $\mathbf{L_C}$ are determined by the locational elements of tariffs.

Table 11 - Residual Calculation

		2016/17	2017/18 Initial	2017/18 June	2017/18 October	2017/18 Draft	2017/18 Final
R_G	Generator residual tariff (£/kW)	0.51	-0.92	-2.09	-1.89	-1.85	-1.85
R_D	Demand residual tariff (£/kW)	45.33	46.34	47.95	46.61	47.98	47.26
G	Proportion of revenue recovered from generation (%)	16.7%	16.4%	14.3%	14.6%	14.6%	14.8%
D	Proportion of revenue recovered from demand (%)	83.3%	83.6%	85.7%	85.4%	85.4%	85.2%
R	Total TNUoS revenue (£m)	2,709	2,735	2,735	2,676	2,666	2,631
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	191.9	266.3	275.3	258.9	272.8	275.0
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-2.4	0.6	-9.7	-3.1	-12.4	-12.4
O	Revenue recovered from offshore local tariffs (£m)	200.6	212.9	223.4	225.1	210.2	208.5
L_G	Revenue recovered from onshore local substation tariffs (£m)	15.9	17.0	17.6	17.6	17.5	17.5
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.3	15.6	14.0	14.6	14.7	14.6
B_G	Generator charging base (GW)	62.9	67.3	67.0	66.6	67.6	67.6
B_D	Demand charging base (GW)	49.8	49.3	49.1	49.1	47.7	47.7

4.2.6 Small Generators Discount

Table 12 – Small Generator Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-1.85
Demand Residual (£/kW)	D	47.26
Small Generator Discount (£/kW)	T = (G + D)/4	11.35
Forecast Small Generator Volume (kW)	V	2,395,260
2017/18 SGD cost (£)	V x T	27,190,316
Prior year reconcilation (£)	R	- 856,870
Total SGD Cost (£)	C = (V x T) + R	26,333,446
Total System Triad Demand (kW)	TD	47,684,351
Total HH Triad Demand (kW)	HHD	13,227,055
Total NHH Consumption (kWh)	NHHD	25,313,203,316
Increase in HH Demand tariff (£/kW)	HHT = C/TD	0.55
Total Cost to HH Customers (£)	HHC = HHT * HHD	7,304,575
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.08
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	19,028,870

The small generators discount has been calculated as £11.351718/kW. This equates to a forecast of £26.3m which is recovered from Suppliers through the HH and NHH tariffs.

5 Comparison of final generation tariffs 2016/17 vs 2017/18

The following section provides details of the wider and local generation tariffs for 2017/18 and how these have changed compared with the 2016/17 tariffs.

5.1 Wider zonal generation tariffs

Table and Figure 1 show the changes in generation wider TNUoS tariffs between 2016/17 and 2017/18.

The key changes between the two years are due to several factors. Plant closures and TEC reductions in zones south of Central England have decreased generation in the South which has the effect of increasing national North to South flows, primarily affecting Peak tariffs. The inclusion of the Western HVDC link has increased Year Round tariffs in Scotland in the zones close to the Northern end of the cable. Similarly, the generation tariffs in the zones at the Southern end have decreased as a result of the local effect of the HVDC flows.

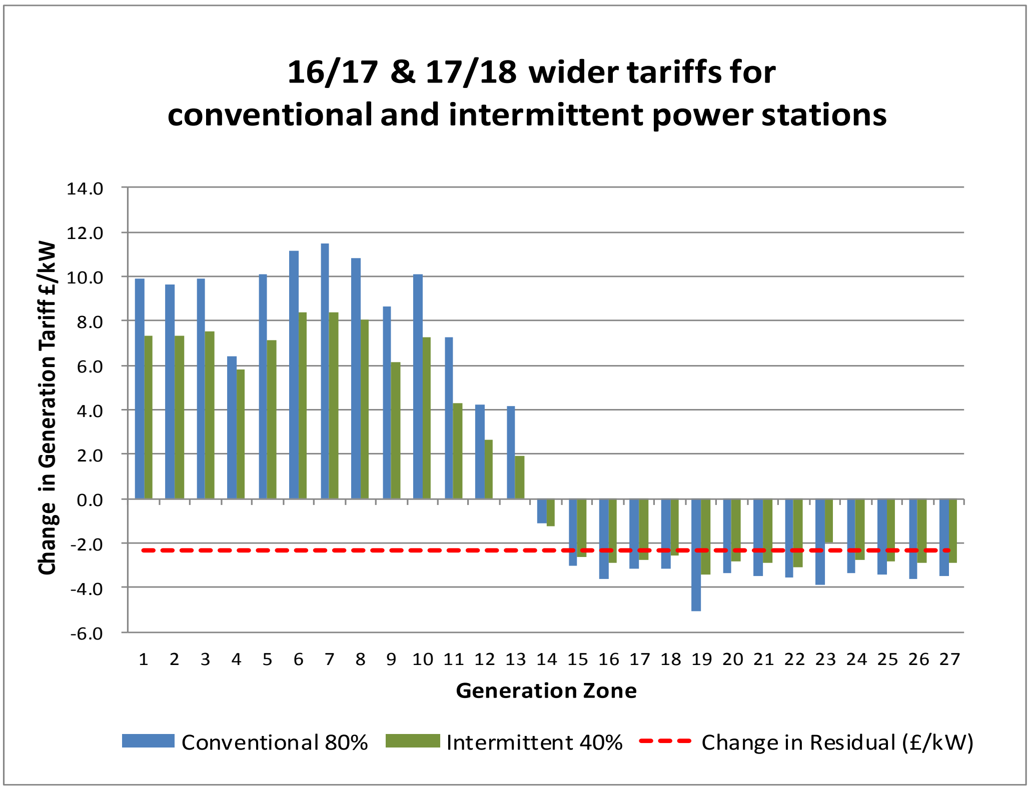
As an example, Table and Figure 1 show how the tariffs change for a conventional generator with an 80% load factor and an intermittent generator with a 40% load factor. Under the Transmit methodology each generator has its own load factor and the 80% and 40% load factors used here are only for illustration.

On average generation tariffs have reduced because lower total forecast generation output (TWh) combined with a weaker Euro have reduced the revenue to be recovered from generation within the €2.5/MWh cap on average annual generator charges.

Table 13 – Generation tariff changes

	Wider Generation Tariffs (£/kW)								
		Conventional 80%			Intermittent 40%			
Zone	Zone Name	2016/17 Final tariffs (£/kW)	2017/18 Final tariffs (£/kW)	Change (£/kW)	2016/17 Final tariffs (£/kW)	2017/18 Final tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	14.70	24.61	9.91	12.48	19.83	7.35	-2.36
2	East Aberdeenshire	10.65	20.31	9.66	9.94	17.29	7.35	-2.36
3	Western Highlands	12.57	22.48	9.91	11.32	18.86	7.54	-2.36
4	Skye and Lochalsh	10.04	16.41	6.38	12.79	18.60	5.81	-2.36
5	Eastern Grampian and Tayside	11.57	21.69	10.12	10.70	17.83	7.14	-2.36
6	Central Grampian	14.67	25.79	11.12	10.95	19.31	8.36	-2.36
7	Argyll	20.20	31.67	11.47	18.53	26.90	8.37	-2.36
8	The Trossachs	10.74	21.54	10.80	8.50	16.54	8.05	-2.36
9	Stirlingshire and Fife	5.68	14.30	8.61	6.70	12.87	6.17	-2.36
10	South West Scotlands	8.99	19.07	10.08	7.60	14.83	7.23	-2.36
11	Lothian and Borders	7.80	15.08	7.27	5.43	9.72	4.29	-2.36
12	Solway and Cheviot	4.93	9.18	4.25	4.57	7.21	2.64	-2.36
13	North East England	2.98	7.12	4.14	1.23	3.16	1.93	-2.36
14	North Lancashire and The Lakes	5.14	3.99	-1.14	3.20	1.97	-1.22	-2.36
15	South Lancashire, Yorkshire and Humber	5.76	2.76	-3.00	1.18	-1.46	-2.64	-2.36
16	North Midlands and North Wales	4.75	1.13	-3.62	0.69	-2.23	-2.93	-2.36
17	South Lincolnshire and North Norfolk	3.23	0.07	-3.16	0.75	-1.99	-2.73	-2.36
18	Mid Wales and The Midlands	2.38	-0.78	-3.16	0.64	-1.93	-2.57	-2.36
19	Anglesey and Snowdon	6.29	1.20	-5.09	0.92	-2.54	-3.45	-2.36
20	Pembrokeshire	7.48	4.09	-3.39	-0.57	-3.41	-2.84	-2.36
21	South Wales & Gloucester	4.63	1.14	-3.49	-0.55	-3.43	-2.88	-2.36
22	Cotswold	0.44	-3.11	-3.55	-3.99	-7.08	-3.09	-2.36
23	Central London	-6.09	-9.96	-3.87	-4.57	-6.51	-1.94	-2.36
24	Essex and Kent	-0.50	-3.87	-3.37	1.75	-1.03	-2.78	-2.36
25	Oxfordshire, Surrey and Sussex	-1.70	-5.14	-3.45	-0.10	-2.92	-2.82	-2.36
26	Somerset and Wessex	-2.62	-6.23	-3.61	-0.55	-3.42	-2.87	-2.36
27	West Devon and Cornwall	-2.40	-5.90	-3.50	-1.07	-3.97	-2.90	-2.36

Figure 1 - Variation in Generation Zonal Tariffs



5.2 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 below.

Table 14 - Circuits subject to one off charges

Node 1	Node 2	Actual Parameters	Amendment in Transport Model	Generator
Wishaw 132kV	Blacklaw 132kV	11.46km of Cable	11.46km of OHL	Blacklaw
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
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
Crystal Rig 132kV	Western Dod 132kV	3.9km of Cable	3.9km of OHL	Aikengall II
Farigaig 132kV	Dunmaglass 132kV	4km Cable	4km OHL	Dunmaglass
Coalburn 132kV	Galawhistle 132kV	9.7km cable	9.7km OHL	Galawhistle II
Melgarve 132kV	Stronelairg 132kV	10km cable	10km OHL	Stronelairg
Moffat 132kV	Harestanes 132kV	15.33km cable	15.33km OHL	Harestanes

5.3 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 – Oct RPI. The change in these tariffs reflects the change in RPI between 2016 and 2015 (see Table 2 above).

5.4 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 transmission owner and indexed by average May to October RPI each year. The change in these tariffs reflects the change in RPI between 2016 and 2015 (see Table 4 above).

6 Comparison of final demand tariffs 2016/17 vs 2017/18

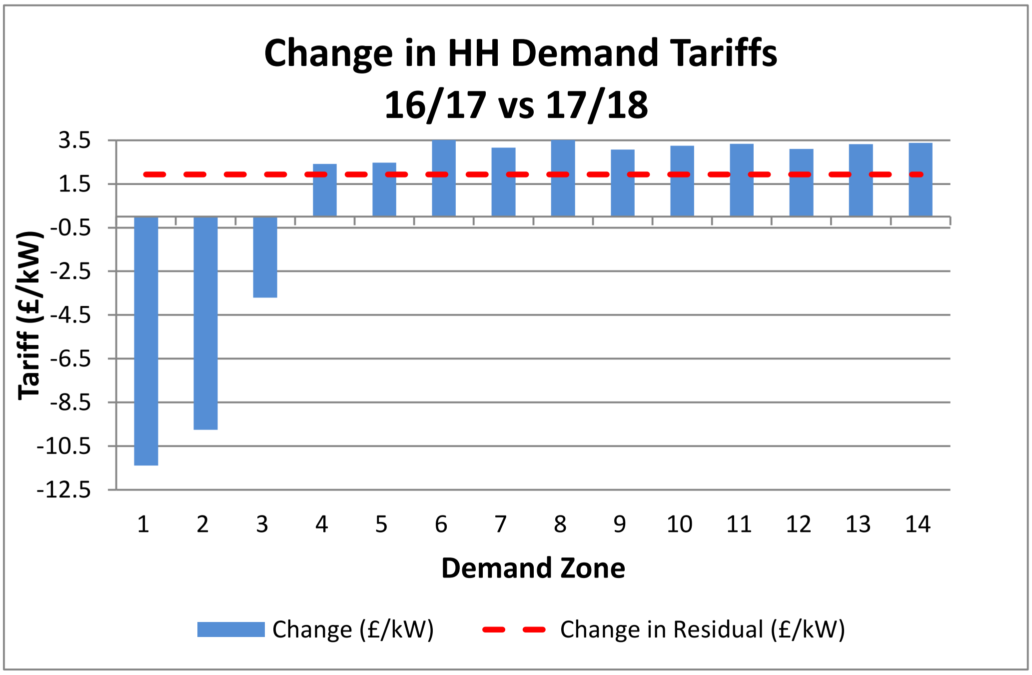
6.1 Half Hour Demand Tariffs

Table 15 and Figure 2 show the difference between the Half-Hourly (HH) demand tariffs forecast in 2016/17 and 2017/18.

Table 15 - Change in HH Demand Tariffs

Zone	Zone Name	2016/17 Final (£/kW)	2017/18 Final (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	40.97	29.58	-11.39	1.93
2	Southern Scotland	40.24	30.48	-9.76	1.93
3	Northern	42.93	39.22	-3.70	1.93
4	North West	42.83	45.25	2.42	1.93
5	Yorkshire	42.49	44.97	2.47	1.93
6	N Wales & Mersey	42.68	46.79	4.11	1.93
7	East Midlands	44.72	47.89	3.16	1.93
8	Midlands	45.74	49.46	3.72	1.93
9	Eastern	46.54	49.62	3.07	1.93
10	South Wales	42.31	45.55	3.25	1.93
11	South East	49.20	52.54	3.33	1.93
12	London	51.87	54.97	3.10	1.93
13	Southern	50.08	53.41	3.33	1.93
14	South Western	48.58	51.96	3.38	1.93

Figure 2 - Change in HH Demand Tariffs



The average HH demand tariff has increased by £3.33/kW due to an increase in revenue being recovered by the HH sector between 2016/17 and 2017/18 to be charged over a similar sized charging base. The increase in revenue to be recovered from HH is due to the reduction in the amount of revenue that can be collected from generation due to the €2.5/MWh cap on average annual generation tariffs.

We also see a reduction in HH demand tariffs in Scotland due to the expected commissioning of the Western HVDC link in 17/18.

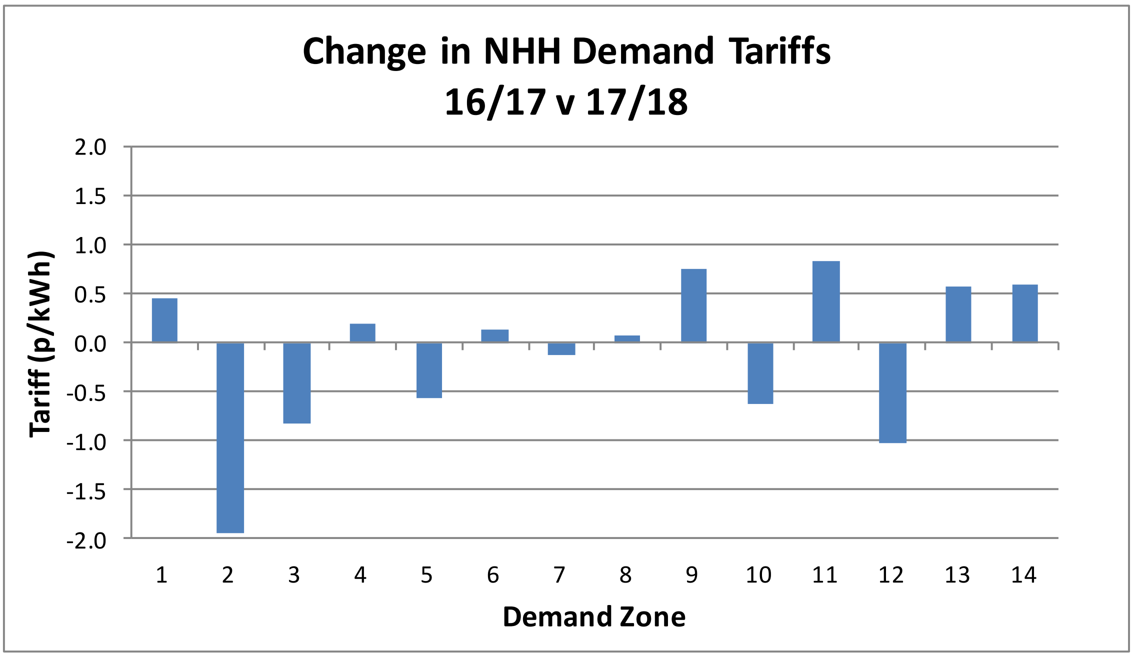
6.2 Non Half-hourly demand tariffs

Table 16 and Figure 3 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in 2016/17 and 2017/18.

Table 16 - NHH Demand Tariff Changes

Zone	Zone Name	2016/17 Final (p/kWh)	2017/18 Final (p/kWh)	Change (p/kWh)
1	Northern Scotland	5.77	6.22	0.45
2	Southern Scotland	6.21	4.26	-1.94
3	Northern	6.77	5.94	-0.82
4	North West	5.69	5.88	0.19
5	Yorkshire	6.54	5.98	-0.56
6	N Wales & Mersey	6.48	6.61	0.13
7	East Midlands	6.38	6.25	-0.13
8	Midlands	6.35	6.43	0.07
9	Eastern	6.35	7.10	0.74
10	South Wales	6.40	5.78	-0.63
11	South East	6.65	7.48	0.82
12	London	6.51	5.49	-1.02
13	Southern	6.49	7.05	0.56
14	South Western	6.88	7.46	0.59

Figure 3 - NHH Tariff Demand Changes



The weighted average Non Half Hour tariff is 0.04p/kWh lower than in 2016/17. This slight reduction is attributable to a lower amount of revenue to be recovered from the NHH sector which has been largely offset by a decrease in the charging base compared to 2016/17. The variations year on year across the zones are attributable to changes in our demand forecast modelling approach which seeks, in particular, to more accurately capture variations in embedded renewable generation across GB.

7 Tools and Supporting Information

7.1 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.

7.2 Charging forums

As there have been very few changes since the Draft tariffs in December 2016, we do not currently plan to hold a webinar for the Final tariffs. However, we welcome questions and are happy to discuss specific aspects of the material contained in the Final tariffs report should you wish to do so.

7.3 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.

7.4 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: Revenue Tables

Appendix B: Locational Demand

Appendix C: Annual Load Factors

Appendix D: Demand Tariffs

Appendix E: Generation Zones

Appendix F: Demand Zones

Appendix A : Revenue Tables

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.

Within the bounds of commercial confidentiality these forecasts provide as much information as possible. Generally allowances determined by Ofgem are shown, whilst those for which Ofgem determinations are expected are not. This respects commercial confidentiality and disclosure considerations and actual revenues may vary for these forecasts.

It is assumed that there is only one set of price changes each year on 1 April.

Table 17 - National Grid Revenue Forecast

			27/01/2017				
Description		**Licence**	**Yr t-1**	**Yr t**	**Yr t+1**	**Yr t+2**	
Regulatory Year			**2014/15**	**2015/16**	**2016/17**	**2017/18**	**Notes**
Actual RPI			256.67				April to March average
RPI Actual		RPIAt	1.190				Office of National Statistics
Assumed Interest Rate		It	0.50%	0.70%	95.00%	0.20%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1,443.8	1,475.6	1,571.4	1554.9	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.5	-114.4	-185.4	-253.3	Deterined by Ofgem
RPI True Up	A3	TRUt	-0.5	4.7	-19.9	-31.4	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.1%	2.5%	1.0%	0.0	HM Treasury Actual/Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	0.0	HM Treasury Actual/Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	0.0	HM Treasury Actual/Forecast
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	1.3	HM Treasury Actual/Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.7**	**1675.5**	**1684.4**	**1614.5**	
Pass-Through Business Rates	B1	RBt		1.2	1.5	2.7	Actual
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	0.0	Actual
Licence Fee	B3	LFt		2.0	2.7	3.2	Actual
Inter TSO Compensation	B4	ITCt		3.8	2.7	0.5	Actual
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	321.0	TSP submission for invoicing
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	301.4	TSH submission for invoicing
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	270.2	OFTO invoicing submissions plus NGSO forecast of expected transfers
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.5	Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.1**	**890.0**	**885.9**	**899.4**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	Actual
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.6	Actual
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	2.6	Actual
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	0.0	Actual
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.0**	**13.9**	**18.7**	**15.3**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.2	Forecast
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	32.1	Determined by Ofgem
Future Environmental Discretionary Rewards	F	EDRt				0.0	Actual
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	0.0	Determined by Ofgem
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	6.1	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	-1.1	Licensee Actual/Forecast
Correction Factor	K	-Kt		56.4	104.0	97.0	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**	
Termination Charges	B5		0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	42.7	41.9	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2631.5**	
Final Collected Revenue	U	TNRt	2375.9	2592.7			Actual
Forecast percentage change to Maximum Revenue M			**0.0%**	**6.2%**	**2.6%**	**-1.5%**	
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**6.4%**	**2.7%**	**-1.6%**	

Table 18 - Scottish Power Revenue Forecast

A breakdown of Scottish Power Revenue has not been made available to NGET.

Table 19 - SHE Transmission Revenue Forecast

A breakdown of SHE Transmission Revenue has not been made available to NGET.

Table 20 - Offshore Transmission Owner Revenues

Offshore Transmission Revenue Forecast	27/01/2017				
Regulatory Year	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**Notes**
Barrow	5.5	5.6	5.7	5.9	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	7.4	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	13.1	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	8.4	Current revenues plus indexation
Walney 2	12.9	13.2	12.5	12.3	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	20.0	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	12.2	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	27.3	Current revenues plus indexation
London Array	37.6	39.2	39.5	39.5	Current revenues plus indexation
Thanet	78.9	17.5	15.7	19.5	Current revenues plus indexation
Lincs		25.6	26.7	27.2	Current revenues plus indexation
Gwynt y mor		26.3	23.6	29.3	Current revenues plus indexation
West of Duddon Sands		35.3	21.3	22.0	Current revenues plus indexation
Humber Gateway	0.0		29.3	9.7	Current revenues plus indexation
Westermost Rough	0.0			11.6	Current revenues plus indexation
Forecast to asset transfer to OFTO in 2017/18	0.0	0.0	0.0	4.7	National Grid Forecast
Forecast to asset transfer to OFTO in 2018/19	0.0	0.0	0.0	0.0	National Grid Forecast
Forecast to asset transfer to OFTO in 2019/20	0.0	0.0	0.0	0.0	National Grid Forecast
Forecast to asset transfer to OFTO in 2020/21	0.0	0.0	0.0	0.0	National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**260.8**	**270.2**	

Notes:

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

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

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

Appendix B : Locational Demand Changes

Table 21 - Demand Profiles

There is no change to demand profiles between the Draft and Final tariffs.

		2016/17 Final				2017/18 Final			
Zone	Zone Name	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)
1	Northern Scotland	623	574	-461	0.73	683	923	-668	0.75
2	Southern Scotland	3,226	3,187	474	1.76	3,070	3,109	642	1.76
3	Northern	2,609	2,216	137	1.32	2,609	2,267	314	1.29
4	North West	4,005	3,682	909	2.09	3,504	3,854	1,175	2.06
5	Yorkshire	4,559	3,897	972	1.90	4,651	3,566	1,107	1.85
6	N Wales & Mersey	2,092	2,981	990	1.31	2,688	2,350	520	1.30
7	East Midlands	4,967	4,797	1,537	2.29	5,137	4,360	1,456	2.23
8	Midlands	4,414	4,225	1,226	2.16	4,498	4,125	1,400	2.10
9	Eastern	5,581	6,046	1,455	3.36	5,850	6,036	1,473	3.19
10	South Wales	1,920	2,252	925	0.88	1,968	1,657	554	0.87
11	South East	3,609	3,631	819	2.08	3,626	3,711	870	2.00
12	London	4,730	4,436	1,763	2.13	5,317	4,112	2,194	1.93
13	Southern	5,814	5,595	1,977	2.80	5,936	5,179	1,650	2.68
14	South Western	2,699	2,282	378	1.35	2,604	2,436	540	1.32
Total		50,848	49,800	13,101	26.15	52,141	47,684	13,227	25.31

Appendix C : Annual Load Factors

Table 25 lists the Annual Load Factors (ALF) of generators expected to be liable for generator charges during 2017/18. ALFs are used to scale the Shared Year Round element of tariffs so each generator 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 2011/12 to 2015/16. Generators which commissioned after 1 April 2013 will have fewer than three complete years of data so the Generic ALF listed in Table 26 are added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2017/18 also use the Generic ALF. The ALFs have been updated from the Draft Tariffs published in December following feedback received from customers.[††]

Table 22: Specific Annual Load Factors

			Yearly Load Factor Source					Yearly Load Factor Value					
Power Station	**Technology**	**Generic Station**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**Specific ALF**
ABERTHAW	Coal	Yes	Actual	Actual	Actual	Actual	Actual	44.5767%	74.0137%	65.5413%	59.0043%	54.2611%	**59.6022%**
ACHRUACH	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.6463%	**36.4210%**
AN SUIDHE WIND FARM	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	34.8406%	31.6380%	41.5843%	36.9422%	35.4900%	**35.7576%**
ARECLEOCH	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	35.1282%	32.4826%	33.8296%	29.7298%	36.8612%	**33.8135%**
BAGLAN BAY	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	61.0787%	27.5756%	16.4106%	37.9194%	29.1228%	**31.5393%**
BARKING	CCGT_CHP		Actual	Actual	Actual	Partial	Generic	20.8541%	2.3383%	1.8802%	13.2096%	0.0000%	**8.3575%**
BARROW OFFSHORE WIND LTD	Offshore_Wind	Yes	Partial	Actual	Actual	Actual	Actual	51.5009%	42.8840%	54.1080%	47.0231%	47.1791%	**49.4368%**
BARRY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	8.2014%	0.6999%	1.2989%	0.4003%	2.1727%	**1.3905%**
BEAULY CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	44.8523%	25.4532%	35.6683%	37.1167%	35.0094%	**35.9315%**
BLACK LAW	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	32.5465%	22.0683%	31.9648%	26.7881%	26.9035%	**28.5521%**
BLACKLAW EXTENSION	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	33.4635%	**36.3601%**
BRIMSDOWN	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	39.5562%	21.8759%	18.7645%	11.1229%	16.4463%	**19.0289%**
BURBO BANK	Offshore_Wind		Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	16.7781%	**37.5881%**
CARRAIG GHEAL	Onshore_Wind		Generic	Partial	Actual	Actual	Actual	0.0000%	32.7219%	45.2760%	48.9277%	45.6254%	**46.6097%**

[††] The Final ALFs report for 2017-18 can be found here:

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

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
CARRINGTON	CCGT_CHP		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	38.7318%	**38.8663%**
CLUNIE SCHEME	Hydro		Actual	Actual	Actual	Actual	Actual	50.3272%	33.4563%	45.3256%	43.2488%	47.9711%	**45.5152%**
CLYDE (NORTH)	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	23.1890%	28.5345%	42.6598%	36.8882%	41.4120%	**40.3200%**
CLYDE (SOUTH)	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	21.1154%	31.6084%	39.8941%	29.4115%	39.9615%	**33.6380%**
CONNAHS QUAY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	33.6741%	18.5104%	12.8233%	18.3739%	28.2713%	**21.7185%**
CONON CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	62.1102%	47.5286%	54.2820%	55.5287%	58.9860%	**56.2656%**
CORBY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	8.1854%	3.4375%	8.0834%	9.6755%	4.5411%	**6.9366%**
CORYTON	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	40.7480%	15.6869%	9.7852%	17.5123%	26.4000%	**19.8664%**
COTTAM	Coal	Yes	Actual	Actual	Actual	Actual	Actual	61.2151%	65.0700%	67.3951%	51.4426%	34.4157%	**59.2426%**
COTTAM DEVELOPMENT CENTRE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	46.0664%	13.7361%	16.0249%	31.3132%	28.2382%	**25.1921%**
COWES	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.2783%	0.1743%	0.0956%	0.3135%	0.4912%	**0.2554%**
CRUACHAN	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	8.9462%	8.4281%	9.6969%	9.0516%	8.8673%	**8.9550%**
CRYSTAL RIG II	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	49.3600%	40.6845%	50.2549%	47.5958%	48.3836%	**48.4464%**
DAMHEAD CREEK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	77.3504%	45.0617%	77.1783%	67.4641%	64.8983%	**69.8469%**
DEESIDE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	35.4538%	19.7551%	17.3035%	13.9018%	17.4579%	**18.1722%**
DIDCOT B	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	56.8079%	49.0134%	18.6624%	25.5345%	41.1389%	**38.5623%**
DIDCOT GTS	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1401%	0.0720%	0.0902%	0.2843%	0.4861%	**0.1715%**
DINORWIG	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	15.0985%	15.0990%	15.0898%	15.0650%	14.6353%	**15.0844%**
DRAX	Coal	Yes	Actual	Actual	Actual	Actual	Actual	81.1523%	82.4774%	80.5151%	82.2149%	76.2030%	**81.2941%**
DUNGENESS B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	11.6712%	59.8295%	61.0068%	54.6917%	70.7617%	**58.5094%**
DUNLAW EXTENSION	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	37.7664%	32.3771%	34.8226%	30.0797%	29.1203%	**32.4265%**
EDINBANE WIND	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	52.8496%	29.3933%	39.4785%	31.2458%	35.5937%	**35.4393%**
EGGBOROUGH	Coal	Yes	Actual	Actual	Actual	Actual	Actual	41.4851%	72.6884%	72.1843%	45.7421%	27.0157%	**53.1372%**
ERROCHTY	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	25.1643%	14.5869%	28.2628%	25.3585%	28.1507%	**26.2245%**
FALLAGO	Onshore_Wind		Generic	Partial	Actual	Actual	Actual	0.0000%	35.7448%	54.8683%	44.7267%	55.7992%	**51.7981%**
FARR WINDFARM TOMATIN	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	43.3953%	34.0149%	44.7212%	38.5712%	40.9963%	**40.9876%**
FASNAKYLE G1 & G3	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	39.9896%	22.1176%	35.3695%	57.4834%	53.1573%	**42.8388%**
FAWLEY CHP	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	71.5686%	61.1362%	63.3619%	72.8484%	57.6978%	**65.3556%**
FFESTINIOGG	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	3.3676%	2.9286%	5.4631%	4.3251%	3.4113%	**3.7013%**
FIDDLERS FERRY	Coal	Yes	Actual	Actual	Actual	Actual	Actual	52.0973%	61.6386%	49.0374%	45.2435%	27.4591%	**48.7927%**
FINLARIG	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	67.9805%	40.2952%	59.9142%	59.4092%	65.1349%	**61.4861%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
FOYERS	Pumped_Storage	Yes	Actual	Actual	Actual	Actual	Actual	18.9885%	13.4800%	14.7097%	12.3048%	15.4323%	**14.5407%**
GARRY CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	70.4039%	48.5993%	55.9308%	64.3828%	60.2772%	**60.1969%**
GLANDFORD BRIGG	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	0.9617%	0.3336%	1.5673%	0.5401%	1.8191%	**1.0230%**
GLENDOE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	0.0000%	17.3350%	36.3802%	32.3494%	34.8532%	**28.1792%**
GLENMORISTON	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	58.0412%	36.3045%	44.4594%	48.7487%	50.6921%	**47.9668%**
GORDONBUSH	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	33.5929%	37.8930%	46.5594%	47.7981%	47.7161%	**47.3579%**
GRAIN	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	29.4910%	25.4580%	41.3833%	44.0031%	39.7895%	**36.8879%**
GRANGEMOUTH	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	67.5783%	52.8594%	55.9047%	62.6168%	59.8274%	**59.4496%**
GREAT YARMOUTH	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	45.0785%	19.0270%	20.7409%	18.6633%	59.8957%	**28.2821%**
GREATER GABBARD OFFSHORE WIND FARM	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	17.8601%	40.1778%	48.3038%	42.1327%	50.2468%	**43.5381%**
GRIFFIN WIND	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	14.0338%	17.9885%	31.9566%	31.3152%	31.0284%	**31.4334%**
GUNFLEET SANDS I	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	43.7552%	50.1496%	56.6472%	47.0132%	50.4650%	**49.2093%**
GUNFLEET SANDS II	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	41.4244%	45.0132%	52.2361%	44.7211%	49.0521%	**46.2622%**
GWYNT Y MOR	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	18.2777%	8.0036%	61.6185%	63.1276%	**44.2499%**
HADYARD HILL	Onshore_Wind		Actual	Actual	Actual	Actual	Actual	38.9802%	27.6927%	31.9488%	27.7635%	36.6527%	**32.1217%**
HARESTANES	Onshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	23.8423%	28.6355%	27.8093%	**26.7624%**
HARTLEPOOL	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	71.1712%	80.2632%	73.7557%	56.2803%	53.8666%	**67.0691%**
HEYSHAM	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	83.7012%	83.3828%	73.3628%	68.8252%	72.7344%	**76.4933%**
HINKLEY POINT B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	56.9291%	61.7582%	68.8664%	70.1411%	67.6412%	**66.0886%**
HUMBER GATEWAY OFFSHORE WIND FARM	Offshore_Wind		Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	62.9631%	**52.9831%**
HUNTERSTON	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	75.3474%	73.5984%	84.7953%	79.1368%	82.1786%	**78.8876%**
IMMINGHAM	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	73.3041%	50.1793%	37.8219%	56.8316%	69.4686%	**58.8265%**
INDIAN QUEENS	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	1.3382%	0.3423%	0.2321%	0.0876%	0.0723%	**0.2207%**
IRONBRIDGE	Biomass	Yes	Generic	Generic	Actual	Actual	Actual	0.0000%	0.0000%	11.0838%	30.9006%	38.6698%	**26.8847%**
KEADBY	CCGT_CHP		Actual	Actual	Actual	Generic	Partial	49.8412%	4.6125%	0.0001%	0.0000%	35.1858%	**18.1513%**
KILBRAUR	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	45.1817%	45.2306%	51.3777%	54.3550%	50.3807%	**48.9964%**
KILLIN CASCADE	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	53.0410%	32.3429%	45.5356%	44.8205%	53.2348%	**47.7990%**
KINGS LYNN A	CCGT_CHP		Actual	Actual	Actual	Actual	Generic	15.6080%	0.0003%	0.0000%	0.0000%	0.0000%	**5.2027%**
LANGAGE	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	60.7905%	41.9115%	40.8749%	34.8629%	16.5310%	**39.2164%**
LINCS WIND FARM	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	19.8148%	46.5987%	43.8178%	49.1306%	**46.5157%**
LITTLE BARFORD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	11.8210%	16.3807%	33.6286%	49.6644%	39.9829%	**29.9974%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
LITTLEBROOK D	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1055%	0.0588%	0.0201%	0.1394%	0.0000%	**0.0615%**
LOCHLUICHART	Onshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	6.4399%	20.2103%	29.2663%	**18.6388%**
LONDON ARRAY	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	47.9931%	51.2703%	64.0880%	66.8682%	**60.7422%**
LYNEMOUTH	Coal		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	83.7381%	**65.8960%**
MARCHWOOD	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	66.1953%	43.3537%	48.6845%	66.4021%	55.0879%	**56.6559%**
MARK HILL	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	26.3795%	30.1675%	30.2863%	26.7942%	34.0227%	**29.0827%**
MEDWAY	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	42.4273%	1.0718%	14.5545%	28.0962%	34.1799%	**25.6102%**
MILLENNIUM	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	47.2065%	42.1318%	52.6618%	53.2636%	48.4038%	**49.4240%**
NANT	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	42.4480%	20.8965%	35.5883%	36.4040%	37.3788%	**36.4571%**
ORMONDE	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	48.5898%	49.6561%	42.8711%	47.1986%	**46.5753%**
PEMBROKE	CCGT_CHP		Generic	Actual	Actual	Actual	Actual	0.0000%	61.5434%	60.3928%	67.5346%	64.5596%	**64.5459%**
PETERBOROUGH	CCGT_CHP		Actual	Actual	Actual	Actual	Partial	3.4546%	0.9506%	1.8311%	1.0929%	0.9933%	**2.1262%**
PETERHEAD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	66.1917%	31.3766%	41.8811%	0.4858%	23.3813%	**32.2130%**
RATCLIFFE-ON-SOAR	Coal	Yes	Actual	Actual	Actual	Actual	Actual	53.5677%	66.7461%	71.7403%	56.1767%	19.6814%	**58.8302%**
ROBIN RIGG EAST	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	41.4118%	37.4157%	46.7562%	55.3209%	51.9700%	**46.7127%**
ROBIN RIGG WEST	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	44.4918%	38.2254%	48.0629%	53.4150%	56.0881%	**48.6565%**
ROCKSAVAGE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	47.7376%	41.4820%	2.6155%	4.4252%	19.8061%	**21.9044%**
RYE HOUSE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	20.4253%	10.7188%	7.4695%	5.3701%	7.7906%	**8.6596%**
SALTEND	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	90.6801%	81.5834%	69.0062%	67.9518%	55.6228%	**72.8471%**
SEABANK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	34.5669%	15.2311%	18.2781%	25.6956%	27.2136%	**23.7291%**
SELLAFIELD	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	4.1046%	14.0549%	25.0221%	18.9719%	28.6790%	**19.3496%**
SEVERN POWER	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	32.2421%	27.7976%	32.4163%	24.6354%	18.3226%	**28.2250%**
SHERINGHAM SHOAL	Offshore_Wind	Yes	Partial	Actual	Actual	Actual	Actual	3.2831%	36.6431%	49.3517%	46.2286%	53.6184%	**49.7329%**
SHOREHAM	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	65.7100%	0.0000%	20.7501%	10.2239%	48.9514%	**26.6418%**
SIZEWELL B	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	77.3818%	96.7260%	82.5051%	84.7924%	98.7826%	**88.0078%**
SLOY G2 & G3	Hydro		Actual	Actual	Actual	Actual	Actual	15.0995%	9.1252%	14.3471%	15.5941%	13.9439%	**14.4635%**
SOUTH HUMBER BANK	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	33.8760%	27.9763%	24.3373%	34.4673%	48.6753%	**32.1065%**
SPALDING	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	65.1849%	34.6976%	33.4800%	39.3092%	47.9407%	**40.6492%**
STAYTHORPE	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	58.4594%	54.4117%	37.6216%	56.6148%	69.4422%	**56.4953%**
STRATHY NORTH & SOUTH	Onshore_Wind		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	53.5472%	**43.0546%**
SUTTON BRIDGE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	64.8794%	20.1652%	9.4124%	17.2025%	13.1999%	**16.8559%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011/12	2012/13	2013/14	2014/15	2015/16	2011/12	2012/13	2013/14	2014/15	2015/16	
TAYLORS LANE	Gas_Oil	Yes	Actual	Actual	Actual	Actual	Actual	0.1048%	0.2037%	0.0483%	0.0640%	0.1708%	**0.1132%**
THANET OFFSHORE WIND FARM	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	32.4868%	41.1093%	39.7489%	35.5935%	41.3434%	**38.8172%**
TODDLEBURN	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	38.1923%	32.7175%	39.5374%	33.7211%	35.0823%	**35.6652%**
TORNESS	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	90.0662%	84.8669%	86.4669%	91.4945%	85.7725%	**87.4352%**
USKMOUTH	Coal	Yes	Actual	Actual	Actual	Partial	Actual	19.2655%	45.1938%	38.9899%	6.1403%	25.5184%	**36.5674%**
WALNEY I	Offshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	45.6003%	44.2799%	57.7046%	52.0555%	50.7535%	**49.4697%**
WALNEY II	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	60.2829%	61.9219%	58.2355%	35.7988%	**51.9854%**
WEST BURTON	Coal	Yes	Actual	Actual	Actual	Actual	Actual	44.5447%	70.5868%	68.9176%	61.5364%	32.7325%	**58.3329%**
WEST BURTON B	CCGT_CHP		Generic	Partial	Actual	Actual	Actual	0.0000%	38.9336%	30.3021%	46.8421%	59.3477%	**45.4973%**
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind		Generic	Generic	Partial	Actual	Actual	0.0000%	0.0000%	47.9931%	40.0506%	48.7540%	**45.5992%**
WESTERMOST ROUGH	Offshore_Wind		Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	13.1278%	54.8014%	**38.6408%**
WHITELEE	Onshore_Wind	Yes	Actual	Actual	Actual	Actual	Actual	31.7670%	28.2265%	35.1074%	29.8105%	31.8773%	**31.1516%**
WHITELEE EXTENSION	Onshore_Wind		Partial	Actual	Actual	Actual	Actual	0.3067%	12.4146%	27.0102%	27.7787%	26.7655%	**27.1848%**
WILTON	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	12.6949%	3.4258%	4.4941%	21.5867%	16.1379%	**11.1090%**
WYLFA	Nuclear	Yes	Actual	Actual	Actual	Actual	Actual	79.4968%	60.0463%	84.4883%	83.5566%	86.5533%	**82.5139%**

Table 23: Generic Annual Load Factors

Technology	Generic ALF
Gas_Oil	0.1645%
Pumped_Storage	10.5704%
Tidal	18.9000%
Biomass	26.8847%
Wave	31.0000%
Onshore_Wind	37.8084%
CCGT_CHP	38.9336%
Hydro	44.3345%
Offshore_Wind	47.9931%
Coal	56.9749%
Nuclear	75.6256%

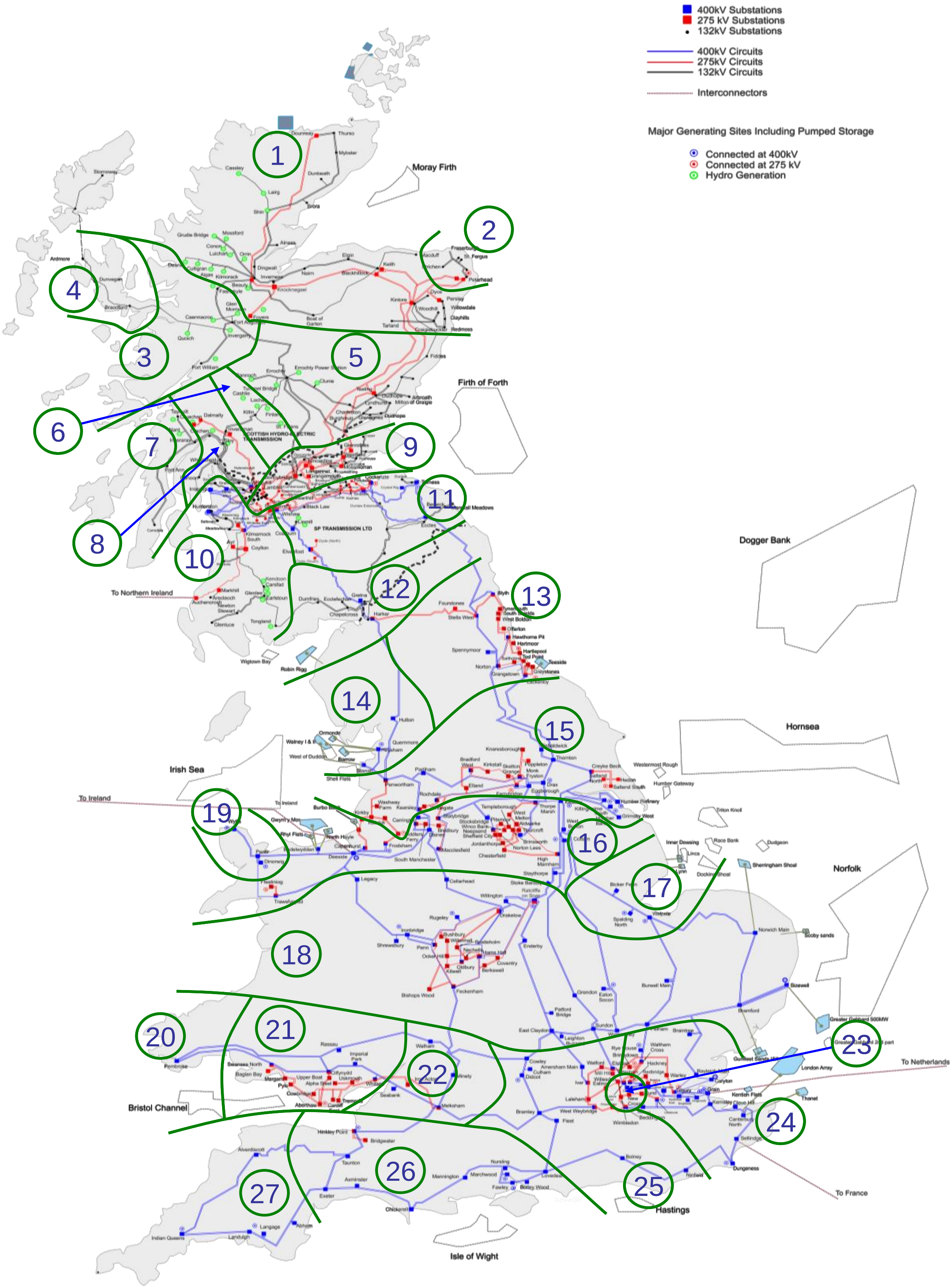
*Note: ALF figures for Wave and Tidal technology are generic figures provided by BEIS due to no metered data being available.

Appendix D : Demand tariffs

Table 24 – Demand Tariffs with breakdown of peak security and year round elements

Zone	Zone Name	Peak Security Tariff	Year Round Tariff	Residual	Small Generators Discount	HH Demand Tariff (£/kW)
1	Northern Scotland	1.87	-20.11	47.26	0.55	29.58
2	Southern Scotland	0.02	-17.35	47.26	0.55	30.48
3	Northern	-2.67	-5.92	47.26	0.55	39.22
4	North West	-0.71	-1.85	47.26	0.55	45.25
5	Yorkshire	-2.58	-0.27	47.26	0.55	44.97
6	N Wales & Mersey	-1.82	0.79	47.26	0.55	46.79
7	East Midlands	-2.13	2.21	47.26	0.55	47.89
8	Midlands	-1.41	3.05	47.26	0.55	49.46
9	Eastern	1.04	0.76	47.26	0.55	49.62
10	South Wales	-6.19	3.92	47.26	0.55	45.55
11	South East	3.86	0.87	47.26	0.55	52.54
12	London	5.04	2.11	47.26	0.55	54.97
13	Southern	1.68	3.91	47.26	0.55	53.41
14	South Western	-0.93	5.08	47.26	0.55	51.96

Appendix E : Generation Zones



Appendix F : Demand Zones