nationalgrid

Tariff Information Paper

December 2016 Draft TNUoS tariffs for 2017/18

This information paper provides National Grid's draft Transmission Network Use of System (TNUoS) tariffs for 2017/18, which apply to Generators and Suppliers. This is the last forecast of 17/18 tariffs before final tariffs are published by 31 January 2017.

National Grid will be hosting a webinar on this report on Thursday 5 January at 13:00pm.

22 December 2016

Contents

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1 Executive Summary

Welcome to our December forecast of draft TNUoS tariffs for 2017/18. This is our fourth forecast of 2017/18 charges this year and precedes publication of the final tariffs at the end of January 2017. The final tariffs will come into effect on 1 April 2017.

Changes to this tariff forecast have predominantly been influenced by changes to generation, Annual Load Factors, the chargeable demand base and Transmission Owner (TO) revenue inputs to the charging models. For generation, an updated contracted generation position as at 31 October 2016 has been used in this forecast and has driven changes to locational charges. In particular there have been increases to 'intermittent' generation tariffs in Scotland of between £1.06/kW and £1.77/kW where changes to model inputs have had the effect of increasing the North-South system flows thereby increasing generation tariffs in the North.

We have updated Annual Load Factors for generation, in accordance with the CUSC Charging Methodology[*], to take into account the latest year of BMU output data. These were published on our website on 9 December and generators have until 6 January 2017 to provide any comments on these.

As we set out in our October tariff report, the chargeable demand base has been updated for these draft tariffs. Our numbers have been informed by Monte Carlo analysis to derive a more statistically accurate view of demand. A forward looking view of system demand, growth in embedded generation and possible weather scenarios have also been included in this process. As a result, we have decreased our forecasts of peak and HH demand, and increased NHH demand compared with our October forecast which has in turn increased HH tariffs by a weighted average of £1.76/kW and NHH tariffs by a weighted average of £0.05/kW. We continue to develop our thinking on forecasting demand use where meters have been migrated to half hourly settlement and we would welcome views from suppliers on this particularly in light of Ofgem's determination on CMP266[†]. This means that there is possibility that we will update our forecast of demand in January however this will be considered only where we feel cost reflectivity would be impacted if a change is not made.

In terms of the revenue input, estimates of TO revenue include latest forecasts from each of the onshore and offshore TOs, and the TO revenue input has decreased by £9.6m since the October forecast. All offshore and onshore TOs have yet to provide their final revenue submission for 2017/18, and so any further changes to revenue will be reflected in the final tariffs in January.

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% and it will remain fixed for the final tariffs.

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

[†] Please see decision tab at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP266/

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 could impact tariffs but unless a mid-year tariff change process is used 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.

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

2 Tariff Summary

This section summarises the draft generation and demand tariff forecasts for 2017/18. Information can be found in later sections on how these tariffs were calculated and why they have changed from the October forecast of 2017/18 tariffs.

2.1 Generation Tariffs 2017/18

Table 1 - Wider Generation Tariffs

Under the Transmit methodology each generator has its own load factor as listed in Appendix D. 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	0.00	11.94	16.91	-1.85	24.61	19.84
2	East Aberdeenshire	0.79	5.58	16.91	-1.85	20.32	17.30
3	Western Highlands	-0.41	10.09	16.68	-1.85	22.49	18.87
4	Skye and Lochalsh	-6.22	10.09	16.42	-1.85	16.42	18.61
5	Eastern Grampian and Tayside	0.27	8.95	16.11	-1.85	21.70	17.84
6	Central Grampian	2.44	10.09	17.13	-1.85	25.79	19.32
7	Argyll	1.56	8.03	25.55	-1.85	31.68	26.91
8	The Trossachs	1.78	8.03	15.18	-1.85	21.55	16.55
9	Stirlingshire and Fife	-0.13	3.91	13.15	-1.85	14.30	12.87
10	South West Scotlands	1.70	6.35	14.15	-1.85	19.08	14.84
11	Lothian and Borders	2.82	6.35	9.03	-1.85	15.08	9.73
12	Solway and Cheviot	0.57	3.50	7.67	-1.85	9.19	7.22
13	North East England	3.14	2.04	4.20	-1.85	7.13	3.17
14	North Lancashire and The Lakes	1.20	2.04	3.01	-1.85	4.00	1.98
15	South Lancashire, Yorkshire and Humber	4.00	0.57	0.16	-1.85	2.77	-1.46
16	North Midlands and North Wales	3.75	-0.95		-1.85	1.14	-2.23
17	South Lincolnshire and North Norfolk	2.19	-0.34		-1.85	0.08	-1.98
18	Mid Wales and The Midlands	1.23	-0.20		-1.85	-0.78	-1.93
19	Anglesey and Snowdon	4.42	-1.70		-1.85	1.21	-2.53
20	Pembrokeshire	9.05	-3.88		-1.85	4.09	-3.40
21	South Wales & Gloucester	6.15	-3.94		-1.85	1.15	-3.42
22	Cotswold	3.15	2.07	-6.06	-1.85	-3.10	-7.08
23	Central London	-4.27	2.07	-5.49	-1.85	-9.95	-6.51
24	Essex and Kent	-3.67	2.07		-1.85	-3.86	-1.02
25	Oxfordshire, Surrey and Sussex	-1.15	-2.67		-1.85	-5.14	-2.91
26	Somerset and Wessex	-1.24	-3.92		-1.85	-6.23	-3.42
27	West Devon and Cornwall	0.20	-5.30		-1.85	-5.89	-3.97

Small Generation Discount (£/kW)	11.534441

Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.18	0.11	0.08
<1320 MW	Redundancy	0.41	0.25	0.18
>=1320 MW	No redundancy		0.33	0.24
>=1320 MW	Redundancy		0.54	0.40

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.94	Dinorwig	2.21	Kilmorack	0.18
Aigas	0.60	Dunlaw Extension	1.38	Langage	0.60
An Suidhe	2.82	Brochlock	1.32	Lochay	0.34
Arecleoch	1.91	Dumnaglass	1.71	Luichart	0.53
Baglan Bay	0.70	Edinbane	-6.29	Mark Hill	0.81
Beinneun Wind Farm	1.38	Earlshaugh Wind Farm	3.46	Margree	5.54
Bhlaraidh Wind Farm	0.59	Ewe Hill	1.26	Marchwood	0.35
Black Hill	0.79	Farr Windfarm	2.07	Millennium Wind	1.68
BlackCraig Wind Farm	5.79	Fallago	0.91	Moffat	0.16
Black Law	1.61	Carraig Gheal	4.05	Mossford	2.65
BlackLaw Extension	3.41	Ffestiniogg	0.23	Nant	2.31
Bodelwyddan	0.11	Finlarig	0.29	Necton	1.03
Carrington	-0.03	Foyers	0.69	Rhigos	0.09
Clyde (North)	0.10	Galawhistle	0.78	Rocksavage	0.02
Clyde (South)	0.12	Glendoe	1.69	Saltend	0.31
Corriegarth	3.47	Ulziside	8.93	South Humber Bank	0.87
Corriemoillie	1.53	Gordonbush	0.38	Spalding	0.26
Coryton	0.05	Griffin Wind	-0.85	Kilbraur	0.24
Cruachan	1.68	Hadyard Hill	2.55	Stronelairg	1.33
Crystal Rig	0.33	Harestanes	2.31	Strathy Wind	2.02
Culligran	1.59	Hartlepool	0.55	Wester Dodds	0.65
Deanie	2.62	Hedon	0.17	Whitelee	0.10
Dersalloch	2.22	Invergarry	1.31	Whitelee Extension	0.27
Didcot	0.48	Kilgallioch	0.97		

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	7.44	38.93	0.97
Greater Gabbard	13.95	32.06	0.00
Gunfleet	16.10	14.79	2.76
Gwynt Y Mor	16.99	16.74	0.00
Lincs	13.91	54.45	0.00
London Array	9.47	32.24	0.00
Ormonde	23.00	42.86	0.34
Robin Rigg East	-0.43	28.19	8.74
Robin Rigg West	-0.43	28.19	8.74
Sheringham Shoal	22.23	26.07	0.57
Thanet	16.93	31.54	0.76
Walney 1	19.85	39.54	0.00
Walney 2	19.71	39.89	0.00
West of Duddon Sands	7.66	37.80	0.00
Westermost Rough	16.13	27.29	0.00
Humber Gateway	13.52	30.51	0.00

2.2 Demand Tariffs 2017/18

Table 5 - Demand Tariffs

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

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	30.40	6.38
2	Southern Scotland	31.30	4.38
3	Northern	40.04	6.07
4	North West	46.07	5.99
5	Yorkshire	45.79	6.09
6	N Wales & Mersey	47.61	6.72
7	East Midlands	48.71	6.36
8	Midlands	50.28	6.53
9	Eastern	50.44	7.21
10	South Wales	46.37	5.88
11	South East	53.36	7.59
12	London	55.79	5.57
13	Southern	54.23	7.16
14	South Western	52.78	7.58

These tariffs include a small generators discount revenue recovery of £0.65/kW and 0.09p/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 and are intended to be forward looking. This 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.

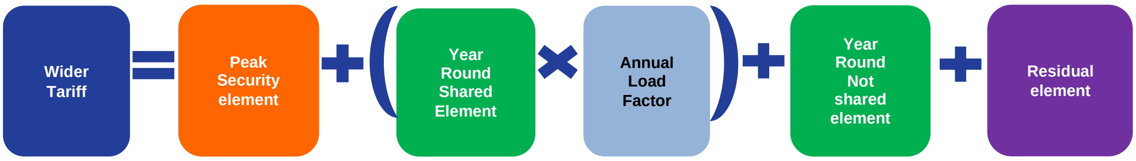
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational “residual” tariff elements are included in the generation and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

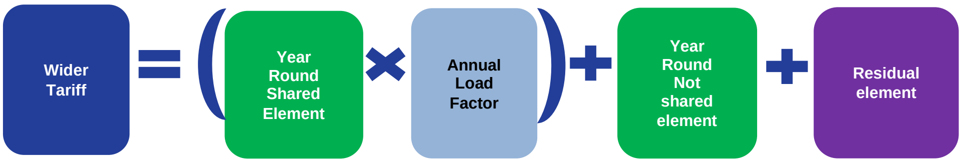
3.2 Charging Principles

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 this forecast are listed in Appendix D. These load factors will be updated based on latest data and final tariffs will be derived using the revised load factors.

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 our forecast in October we have updated: contracted generation, chargeable generation, Scottish embedded generation, annual load factors, chargeable demand, local circuit and revenue data. There have been no changes made to the charging methodology 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

4.1.1 Forecast Contracted Generation 31 October 2016

We have updated generation for 2017/18 using the contracted generation background, published in the TEC register, as at 31 October 2016.

The charging methodology states that we fix the modelled generation background based on the contracted background as at 31 October 2016[§], hence there will be no change to this input for the January final tariffs.

Table 6 - Contracted and Modelled TEC

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

4.1.2 Locational Demand

The locational element of tariffs is based upon week 24 demand forecast data provided by the Distribution Network Operators (DNO) under the Grid Code, forecasts of demand at directly connected demand sites such as steelworks and railways and the effect of some embedded generation. Whilst it was not expected that this data would change significantly from that used in the October forecast, we have had to make a correction to the week 24 demand dataset. The reason for this is that a significant amount of Scottish embedded generation had not been deducted from demand due to some issues with the original submitted data. This has now

[§] The 31 October freeze date for contracted generation is historically linked to the Seven Year Statement October update. This has been replaced by the Electricity Ten Year Statement (ETYS), normally published in November and updated in May. However the contracted generation position is now published more regularly under the TEC register.

been incorporated in the Draft tariffs and has resulted in increased generation tariffs and decreased demand tariffs in Scotland.

4.1.3 Transmission network

Small changes to circuit data have been updated within the model for this forecast following publication of the National Grid Electricity Ten Year Statement.

4.1.4 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. Note that the table below reflects the contracted position of interconnectors on 31 October 2016.

Table 7 – Interconnectors

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

4.1.5 RPI

The RPI index for the components detailed below is derived as the percentage increase of the average May – October RPI for 16/17 compared to 15/16.

Expansion Constant

The expansion constant has decreased to £13.575354/MWkm from the October forecast of £13.588433/MWkm to reflect marginally lower actual RPI compared to that forecast. 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 substation tariffs are reduced by RPI as are offshore local circuit tariffs. The change in RPI has been reflected in the tariffs, which show a small decrease since October.

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 tariffs.

The Scottish TO revenue forecast has increased by £5.8m. This is as a result of increased RPI and a £4m Environmental Discretionary Award as published by Ofgem. Scottish Hydro Electric revenue has increased from the previous forecast by £7.8m. Whilst the detail of the breakdown was not given, it is known that RPI has increased base revenue.

The OFTO revenue has reduced by £19m. This is as a result of commissioning dates of future offshore projects being delayed. The forecast now assumes that only one offshore wind farm will asset transfer in 2017/18.

National Grid Electricity Transmission revenue has increased by £3.2m. Increases in RPI has increased revenue, although this was offset a little by the reduction in Kt as a result of the Ofgem decision to change the way the Customer and Stakeholder Incentive is calculated (from 2013/14 onwards). In addition, on 30 November 2016, Ofgem published its funding decision on the 2016 Network Innovation Competition which awards £33.1m to four projects. This is a reduction to our October forecast of £40.5m for this item.

Tariffs have therefore been calculated to recover £2,666.0m of revenue. This is a reduction of £9.6m from the October forecast of £2,675.6m. All TOs, onshore and offshore, are required to submit actual revenue requirements to NGSO by 25 January 2017 in time for setting final tariffs.

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*	
Less income from connections	*42.7*	*46.5*	*46.5*	*44.1*	*44.0*	
Income from TNUoS	**1,785.5**	**1,760.0**	**1,764.7**	**1,706.3**	**1,709.5**	
Scottish Power Transmission						
Price controlled revenue	*306.4*	*347.1*	*341.0*	*327.7*	*333.5*	
Less income from connections	*11.8*	*13.9*	*14.0*	*11.4*	*11.4*	
Income from TNUoS	**294.6**	**333.1**	**327.0**	**316.3**	**322.1**	
SHE Transmission						
Price controlled revenue	*326.2*	*328.5*	*327.3*	*305.8*	*312.6*	
Less income from connections	*3.4*	*3.6*	*3.6*	*(13.6)*	*(14.6)*	
Income from TNUoS	**322.8**	**324.9**	**323.7**	**319.4**	**327.2**	
Offshore	**260.8**	**276.5**	**279.2**	**293.0**	**274.1**	
Network Innovation Competition	**44.9**	**40.5**	**40.5**	**40.5**	**33.1**	
Total to Collect from TNUoS	**2,708.7**	**2,735.0**	**2,735.1**	**2,675.6**	**2,666.0**	

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

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/£. Under the current methodology this value will not change between now and actual charges being set in January 2017.

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.

Error Margin

The error margin remains unchanged from the June forecast of 21% and will not change prior to final tariffs being set in January.

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

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. This has been updated from the October forecast, using latest demand forecast data from our Demand Forecasting team based in Wokingham. There has been a step change in demand, with an overall reduction in system demand at Triad as well as Half-Hour metered demand at Triad, and an increase in Non-Half Hour demand.

These changes reflect further improvement to the forecasting methodology used, which we hope will increase tariff accuracy for appropriate revenue recovery.

TNUoS demand tariff forecasts depend critically on the outturn of the Triad demands as well as the dates of these Triads, in a coming winter period, as well as on year round non-half-hourly customer demand. They also depend on how much distributed generation is being generated over the potential Triad periods. Both the actual Triad demands and intermittent (mostly wind) generation are highly variable year on year, which makes it difficult to forecast with a high degree of accuracy. Our demand numbers have therefore been informed by Monte Carlo analysis to derive a more statistically accurate view of demand across the zones. A forward looking view of system demand, growth and variability in embedded generation and possible weather scenarios have also been inputted to this process to ensure that future trends are captured.

We continue to develop our thinking on forecasting demand use where meters have been migrated to half hourly settlement and we would welcome views from suppliers on this particularly in light of Ofgem's determination on CMP266[**]. This means that there is the potential for us to update our forecast in January however this will be considered only where we feel cost reflectivity would be impacted if a change is not made.

[**] Please see decision tab at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP266/

Table 10 - Charging Base

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

4.2.4 Annual Load Factors

The Annual Load Factors of each power station are required to calculate tariffs. For the purposes of this forecast we have calculated new ALFs which we published on 9 December 2016. The draft of the new ALFs, based upon data from 2011/12 - 2015/16 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
R_G	Generator residual tariff (£/kW)	0.51	-0.92	-2.09	-1.89	-1.85
R_D	Demand residual tariff (£/kW)	45.33	46.34	47.95	46.61	47.98
G	Proportion of revenue recovered from generation (%)	16.7%	16.4%	14.3%	14.6%	14.6%
D	Proportion of revenue recovered from demand (%)	83.3%	83.6%	85.7%	85.4%	85.4%
R	Total TNUoS revenue (£m)	2,709	2,735	2,735	2,676	2,666
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	191.9	266.3	275.3	258.9	272.8
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-2.4	0.6	-9.7	-3.1	-12.4
O	Revenue recovered from offshore local tariffs (£m)	200.6	212.9	223.4	225.1	210.2
L_G	Revenue recovered from onshore local substation tariffs (£m)	15.9	17.0	17.6	17.6	17.5
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.3	15.6	14.0	14.6	14.7
B_G	Generator charging base (GW)	62.9	67.3	67.0	66.6	67.6
B_D	Demand charging base (GW)	49.8	49.3	49.1	49.1	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	47.98
Small Generator Discount (£/kW)	T = (G + D)/4	11.53
Forecast Small Generator Volume (kW)	V	2,368,260
2017/18 SGD cost (£)	V x T	27,316,555
Prior year reconcilation (£)	R	- 3,605,528
Total SGD Cost (£)	C = (V x T) + R	23,711,028
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	0.50
Total Cost to HH Customers (£)	HHC = HHT * HHD	6,577,149
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.07
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	17,133,879

The small generators discount has been calculated as £11.53/kW. This equates to a forecast £27.3m which is recovered from Suppliers through the HH and NHH tariffs.

5 Forecast generation tariffs for 2017/18

The following section provides details of the forecast wider and local generation tariffs for 2017/18 and changes to the previous tariff forecast.

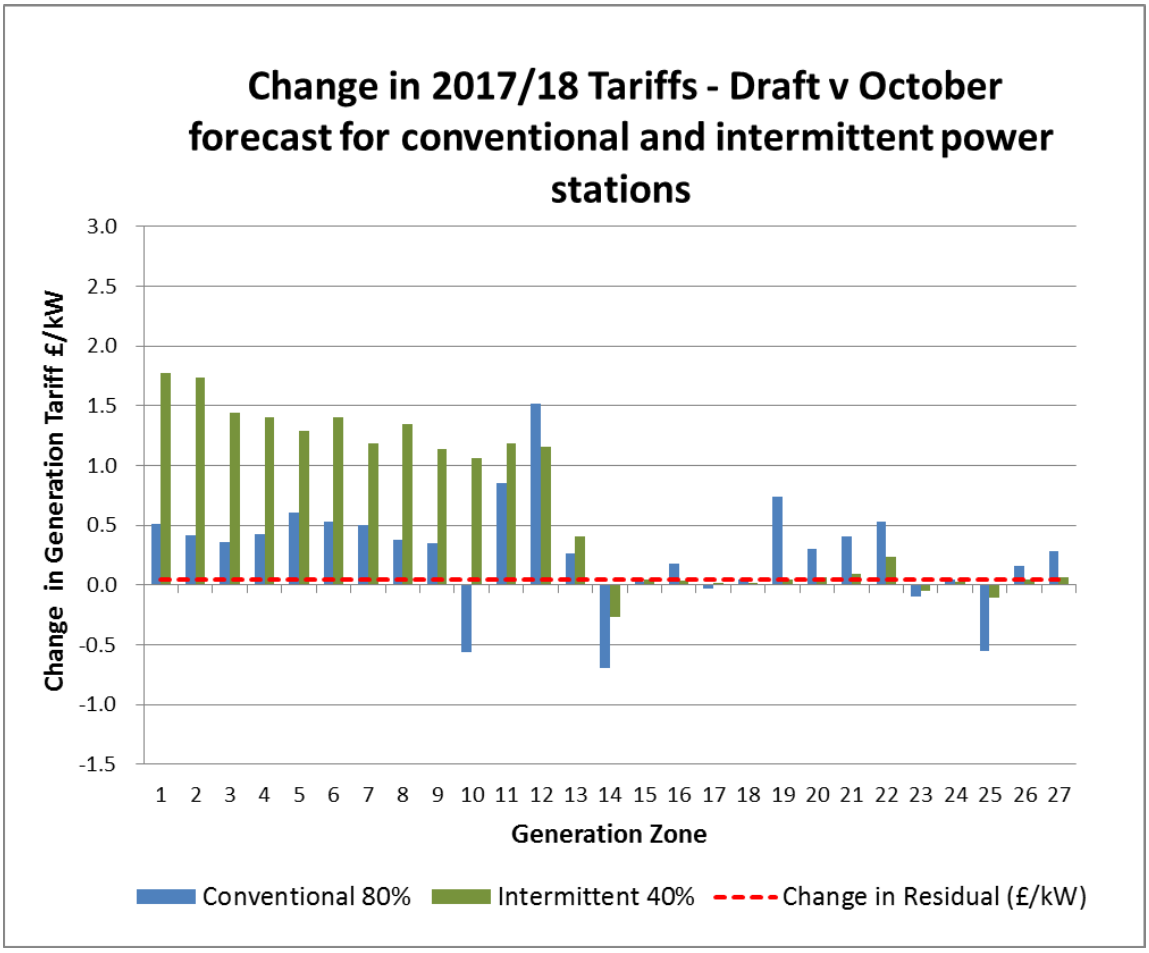
5.1 Wider zonal generation tariffs

Table 13 and Figure 1 show the changes in wider zonal generation TNUoS tariffs between the October forecast and this forecast for a conventional generator with 80% load factor and an intermittent generator with 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.

Table 13 – Generation tariff changes

Wider Generation Tariffs (£/kW)								
		Conventional 80%			Intermittent 40%			
Zone	Zone Name	2017/18 Oct Forecast (£/kW)	2017/18 Draft tariffs (£/kW)	Change (£/kW)	2017/18 Oct Forecast (£/kW)	2017/18 Draft tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	24.10	24.61	0.51	18.07	19.84	1.77	0.04
2	East Aberdeenshire	19.90	20.32	0.42	15.56	17.30	1.73	0.04
3	Western Highlands	22.14	22.49	0.36	17.42	18.87	1.44	0.04
4	Skye and Lochalsh	16.00	16.42	0.42	17.21	18.61	1.40	0.04
5	Eastern Grampian and Tayside	21.09	21.70	0.61	16.56	17.84	1.29	0.04
6	Central Grampian	25.26	25.79	0.53	17.91	19.32	1.41	0.04
7	Argyll	31.17	31.68	0.51	25.73	26.91	1.18	0.04
8	The Trossachs	21.17	21.55	0.38	15.21	16.55	1.34	0.04
9	Stirlingshire and Fife	13.95	14.30	0.35	11.74	12.87	1.14	0.04
10	South West Scotlands	19.64	19.08	-0.56	13.78	14.84	1.06	0.04
11	Lothian and Borders	14.24	15.08	0.85	8.55	9.73	1.18	0.04
12	Solway and Cheviot	7.67	9.19	1.52	6.07	7.22	1.16	0.04
13	North East England	6.87	7.13	0.26	2.76	3.17	0.41	0.04
14	North Lancashire and The Lakes	4.69	4.00	-0.69	2.25	1.98	-0.27	0.04
15	South Lancashire, Yorkshire and Humber	2.75	2.77	0.03	-1.50	-1.46	0.05	0.04
16	North Midlands and North Wales	0.96	1.14	0.18	-2.26	-2.23	0.04	0.04
17	South Lincolnshire and North Norfolk	0.10	0.08	-0.03	-2.00	-1.98	0.02	0.04
18	Mid Wales and The Midlands	-0.83	-0.78	0.05	-1.94	-1.93	0.02	0.04
19	Anglesey and Snowdon	0.47	1.21	0.74	-2.58	-2.53	0.05	0.04
20	Pembrokeshire	3.79	4.09	0.30	-3.47	-3.40	0.07	0.04
21	South Wales & Gloucester	0.74	1.15	0.41	-3.52	-3.42	0.09	0.04
22	Cotswold	-3.64	-3.10	0.53	-7.31	-7.08	0.24	0.04
23	Central London	-9.86	-9.95	-0.09	-6.46	-6.51	-0.05	0.04
24	Essex and Kent	-3.91	-3.86	0.04	-1.05	-1.02	0.02	0.04
25	Oxfordshire, Surrey and Sussex	-4.58	-5.14	-0.56	-2.81	-2.91	-0.11	0.04
26	Somerset and Wessex	-6.39	-6.23	0.16	-3.46	-3.42	0.04	0.04
27	West Devon and Cornwall	-6.18	-5.89	0.28	-4.03	-3.97	0.07	0.04

Figure 1 - Variation in Generation Zonal Tariffs



Locational Tariff

The locational part of the tariff has changed as a consequence of the changes between predicted contracted TEC and actual contracted TEC as at 31 October 2016.

A reduction in locational demand in Scotland due to the correction of week 24 demand data and removal of a significant amount of embedded generation in Zone 2 has led to changes in flows, resulting in some circuits switching from the Peak Security to Year Round scenario, particularly in Scotland and the north of England. The effect of these changes is an increase in intermittent tariffs in zones 1 – 13 and a small increase in conventional tariffs in zones 1 – 9.

A large reduction in conventional generation in the South of England due to a contract not having being signed by 31 October, as had been expected under the October contracted generation forecast, resulted in further increases to intermittent generation tariffs in zones 1-11. This reduction in conventional generation also causes remaining generators elsewhere to increase to meet peak demand. This leads to slight increases in tariffs for zones on the edges of the system which have peak generation contracted for 2017/18.

Zone 14 has very few generators and so the flows on the circuits are liable to change direction, causing changes in tariffs as a result of small changes in generation and demand.

Zone 19 has seen tariff increases primarily due to flow changes as a result of the overall generation, demand and circuit changes across the whole system.

Residual Tariff

The forecast negative residual element of the tariff has become less negative by £0.04/kW since our October forecast and average generation charges have decreased by -£0.09/kW. This small change in tariffs is mainly caused by the locational demand and generation changes detailed above, offset by a larger generation charging base compared to the October forecast.

5.2 Onshore local circuit tariffs

Onshore local circuit tariffs have been updated from the October forecast. Many of the generators that are on spurs will see little change to their tariffs (RPI indexation changes only). Variations from the October forecast are generally caused by changes in flows on surrounding circuits. Circuit data for local circuits has been updated in accordance with our latest Electricity Ten Year Statement document. This may effect a change to some local tariffs if the topology and configuration of surrounding circuits have changed in the Electricity Ten Year Statement, or if a substation is re-categorised from non MITS to MITS. For example, the south west Scotland area has seen changes to Black Craig – Margree – New Cumnock circuits, which has impacted the associated local circuit tariffs as set out in Table 3 above. If you require further information around a particular local circuit tariff please feel free to contact us.

Charging modification CMP203 requires circuits in the transport model to be modelled differently from the actual circuit parameters if they have been subject to a one off charge[‡‡]. Table 14 lists those circuits which we will amend for 2017/18 to reflect the fact that the customer has already paid/or will pay for the non-standard incremental cost.

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 have been updated from the October forecast to reflect actual RPI. All actual RPI data has been incorporated and hence there should be no further changes to these tariffs

[‡‡] CUSC section 14.15.12 to 14.15.20

5.4 Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) have been updated from the October forecast to reflect latest forecast RPI. All “actual” RPI data has been incorporate revenue has been incorporated in these calculations and hence no further changes to these tariffs are expected. Offshore local generation tariffs associated with Offshore Transmission Owners yet to be appointed will be calculated following their appointment.

6 Forecast demand tariffs for 2017/18

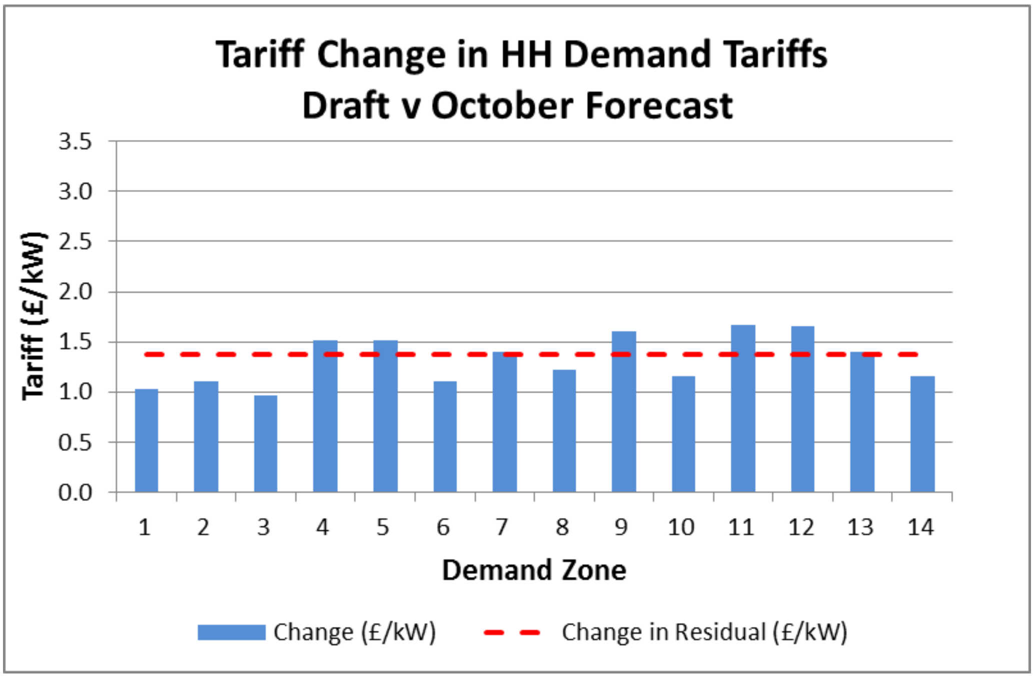
6.1 Half Hour Demand Tariffs

Table 15 and Figure 2 show the difference between the Half-Hourly (HH) demand tariffs forecast in October and this Draft forecast.

Table 15 - Change in HH Demand Tariffs

Zone	Zone Name	2017/18 Oct (£/kW)	2017/18 Draft (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	29.37	30.40	1.03	1.38
2	Southern Scotland	30.19	31.30	1.11	1.38
3	Northern	39.07	40.04	0.97	1.38
4	North West	44.55	46.07	1.52	1.38
5	Yorkshire	44.27	45.79	1.52	1.38
6	N Wales & Mersey	46.50	47.61	1.11	1.38
7	East Midlands	47.31	48.71	1.40	1.38
8	Midlands	49.06	50.28	1.22	1.38
9	Eastern	48.84	50.44	1.60	1.38
10	South Wales	45.22	46.37	1.15	1.38
11	South East	51.69	53.36	1.67	1.38
12	London	54.14	55.79	1.65	1.38
13	Southern	52.82	54.23	1.40	1.38
14	South Western	51.61	52.78	1.16	1.38

Figure 2 - Change in HH Demand Tariffs



Locational Tariff

Locational changes across the majority of the country are small. This is apparent from the small change in most zones above and below the residual line. The greatest changes are reductions in Scotland and the North of England (Zones 1-3) due to the removal of embedded generation from the locational demand forecast in Zone 2.

Residual Tariff

The residual tariff element of HH demand tariffs has increased by £1.38/kW since the October forecast. The main contributor to this change is the decrease in the chargeable demand base.

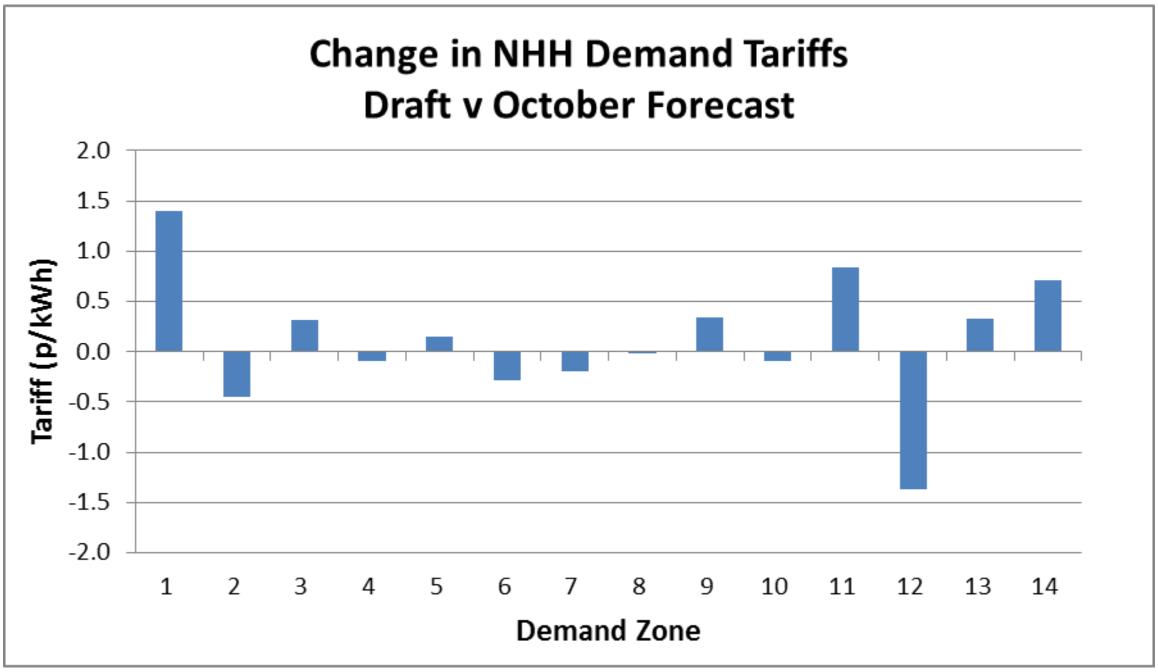
6.2 Non Half-hourly demand tariffs

Table 16 and Figure 3 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in October and these Draft tariffs.

Table 16 - NHH Demand Tariff Changes

Zone	Zone Name	2017/18 October (p/kWh)	2017/18 Draft (p/kWh)	Change (p/kWh)
1	Northern Scotland	4.98	6.38	1.40
2	Southern Scotland	4.83	4.38	-0.45
3	Northern	5.75	6.07	0.32
4	North West	6.08	5.99	-0.09
5	Yorkshire	5.94	6.09	0.15
6	N Wales & Mersey	7.01	6.72	-0.28
7	East Midlands	6.55	6.36	-0.20
8	Midlands	6.54	6.53	0.00
9	Eastern	6.87	7.21	0.34
10	South Wales	5.97	5.88	-0.09
11	South East	6.75	7.59	0.84
12	London	6.95	5.57	-1.37
13	Southern	6.83	7.16	0.33
14	South Western	6.87	7.58	0.71

Figure 3 - NHH Tariff Demand Changes



The forecast weighted average Non Half Hour tariff is 0.05p/kWh higher than in the October forecast. This is predominantly as a result of the increase in the residual element of the tariff. The larger changes seen in Zones 1, 11 and 12 are due to the changes to the chargeable demand forecast.

7 Sensitivities & Uncertainties for 2017/18

7.1 Transmission revenue requirements

Table 17 illustrates the sensitivity of the forecast tariffs to a £50m change in the revenue collected from TNUoS tariffs. This scenario does not represent a minimum or maximum tariff range.

Table 17 – Impact of change in TNUoS Revenue

£50m increase in revenue recovered from TNUoS	
Change in Generation Tariffs (£/kW)	0.00
Change in HH Demand Tariffs (£/kW)	1.02
Change in NHH Demand Tariffs (p/kWh)	0.14

7.2 Demand charging base

An increase in the demand charging base decreases tariffs. Table 18 shows the impacts of a 2% increase in system and HH chargeable demand.

Table 18 - Impact of 2% increase in system and HH in demand

Change in Demand		Change in Tariff	
Peak Demand (MW)	982		
HH Demand (MW)	328	HH Tariff (£/kW)	-0.94
NHH Demand (TWh)	0	NHH Tariff (£/kWh)	0

7.3 Generation charging base

The tariffs presented in this document are based upon the contracted generation background for 2017/18 as of 31 October 16 adjusted to our current view. The locational element of tariffs will be fixed using the contracted background as at 31 October 2016. However the residual element of generation tariffs may continue to be adjusted up to when tariffs are finalised in January 2017, to reflect any final changes to the TO revenues.

8 Tools and Supporting Information

8.1 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.

8.2 Charging forums

We will be hosting a webinar on Thursday 5 January 2017 at 13:00pm to present the material in this forecast and answer questions in an open forum.

8.3 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.

8.4 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: Generation changes for 2017/18

Appendix C: Locational Demand changes

Appendix D: Annual Load Factors

Appendix E: Demand Tariffs

Appendix F: Generation Zones

Appendix G: Demand Zones

Appendix A : Revenue Tables

These pages provide more detail on the price control forecasts for National Grid, Scottish Power Transmission and SHE Transmission. Revenue for offshore networks is also 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.

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.

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 19 - National Grid Revenue Forecast

			01/12/2016				
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	Determined by Ofgem/Licensee forecast
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 Forecast
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	0.0	HM Treasury Forecast
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	0.0	HM Treasury Forecast
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	1.3	Using HM Treasury 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	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt		2.0	2.7	3.2	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt		3.8	2.7	0.5	Licensee Actual/Forecast
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	322.1	14/15 & 15/16 & 16/17 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	327.2	14/15 & 15/16 & 16/17 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	274.1	14/15 & 15/16 & 16/17 Charge setting. Later from OFTO Calculation.
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	0.7	0.7	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**745.1**	**890.0**	**885.9**	**930.4**	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.2	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	2.6	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**0.0**	**13.9**	**18.7**	**14.8**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.2	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	33.1	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt				0.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	0.0	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	4.9	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt		56.4	104.0	102.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2751.3**	**2709.9**	
Termination Charges	B5		0.0	0.0	0.0	**0.0**	
Pre-vesting connection charges	P		47.0	45.0	42.7	44.0	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2666.0**	
Final Collected Revenue	U	TNRt	2375.9	2587.9			Licensee Actual/Forecast
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 20 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast			Updated:	Draft			
Description		Licence Term	Yr t-1 2014/15	Yr t 2015/16	Yr t+1 2016/17	Yr t+2 2017/18	Notes
Actual RPI			256.67		-		April to March average
RPI Actual		RPIAt	1.1900		-		Office of National Statistics
Assumed Interest Rate		It	0.50%	0.63%	1.13%		National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	237.0	`	244.7		
Price Control Financial Model Iteration Adjustment	A2	MODt	6.2	-20.3	-21.8		
RPI True Up	A3	TRUt	-0.1	0.8	-3.9		
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327		National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**292.9**	**-23.9**	**270.0**		
Pass-Through Business Rates	B1	RBt	0.0	-20.2	-4.5		
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	0.0		
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**0.0**	**-20.2**	**-4.5**		
Reliability Incentive Adjustment	C1	RIt	0.0	2.6	3.0		
Stakeholder Satisfaction Adjustment	C2	SSOt	0.0	1.7	2.1		
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	0.0	-0.2	0.1		
Awarded Environmental Discretionary Rewards	C4	EDRt	0.0	0.0	0.0		
Financial Incentive for Timely Connections Output	C5	-CONADJt	0.0	-0.1	0.0		
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**0.0**	**4.0**	**5.2**		
Network Innovation Allowance	D	NIAt	0.7	1.0	1.0		
Transmission Investment for Renewable Generation	G	TIRGt	32.2	38.1	31.7		
Correction Factor	K	-Kt	0.0	-4.9	3.0		
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**325.8**	**-5.9**	**306.4**		
Excluded Services	P	EXCt	7.7	8.0	9.4		Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	18.5	18.8	21.8		Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**	**315.0**	**-16.7**	**294.0**	**322.1**	General System Charge
Final Collected Revenue	U	TNRt	312.2				
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**-105.3%**	**-1858.9%**	**9.5%**	

Table 21 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast			Updated:	Draft			
			Yr t-1	Yr t	Yr t+1		
Description		Licence Term	2014/15	2015/16	2016/17	2017/18	Notes
Actual RPI			256.67		-		April to March average
RPI Actual		RPIAt	1.1900		-		Office of National Statistics
Assumed Interest Rate		It	0.50%	0.63%	1.13%		National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	111.5	124.1	123.6		
Price Control Financial Model Iteration Adjustment	A2	MODt	8.7	85.2	87.6		
RPI True Up	A3	TRUt	-0.0	0.5	-2.6		
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327		SHET figures changed to NG forecast so all Tos are consistent.
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**144.9**	**257.4**	**257.2**		
Pass-Through Business Rates	B1	RBt	0.0	-0.7	-16.0		
Temporary Physical Disconnection	B2	TPDt	0.0	0.6	0.1		
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**0.0**	**-0.1**	**-15.8**		
Reliability Incentive Adjustment	C1	RIt		1.2	0.2		
Stakeholder Satisfaction Adjustment	C2	SSOt		1.6	2.3		
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		-0.3	-0.2		
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	0.0		
Financial Incentive for Timely Connections Output	C5	-CONADJt		0.0	0.0		
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**0.0**	**2.5**	**2.3**		
Network Innovation Allowance	D	NIAt	1.3	1.7	1.7		
Transmission Investment for Renewable Generation	G	TIRGt	72.2	81.3	79.9		
Compensatory Payments Adjustment	J	SHCPt	0.0	0.4	0.0		
Correction Factor	K	-Kt		-1.7	0.9		
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**218.3**	**341.5**	**326.2**		
Excluded Services	P	EXCt	0.0	0.0	0.0		Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	3.5	3.5	3.5		Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**	**214.9**	**338.0**	**322.7**	**327.2**	General System Charge
Final Collected Revenue	U	TNRt	217.4	0.0	0.0		
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**57.3%**	**-4.5%**	**1.4%**	

Table 22 - Offshore Transmission Owner Revenues

<table>
<tr><th colspan="1">Offshore Transmission Revenue Forecast</th><th colspan="4">15/12/2016</th><th></th></tr>
<tr><th>Description</th><th>Yr t-1</th><th>Yr t</th><th>Yr t+1</th><th>Yr t+2</th><th rowspan="2">Notes</th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th><th>2017/18</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>5.9</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>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>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>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>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.1</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>12.1</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>27.4</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>38.9</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>19.7</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>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>31.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>21.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Humber Gateway</td><td>0.0</td><td rowspan="2">29.3</td><td>11.8</td><td>Current revenues plus indexation</td></tr>
<tr><td>Westermost Rough</td><td>0.0</td><td>12.5</td><td>Current revenues plus indexation</td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2017/18</td><td>0.0</td><td>0.0</td><td>0.0</td><td>4.6</td><td>National Grid Forecast</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>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>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>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>274.1</td><td></td></tr>
</table>

Notes:

All monies are nominal 'money of the day' prices unless stated otherwise

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 : Generation changes for 2017/18

Table 23 shows TEC changes notified between September 2016 (used for the October forecast) and 31 October 2016 (used for these Draft tariffs.)

Stations with Bilateral Embedded Generator Agreements for less than 100MW TEC are not chargeable and are not included in this table. The tariffs in this forecast are based on National Grid's best view and therefore may include different generation to that shown below.

Table 23 - Generation TEC Changes

Power Station	Node	MW Change	Zone
Lion Hill Wind Farm	CLYS2R	-9.2	11

Appendix C : Locational Demand changes

Table 24 - Demand Profiles

		2017/18 October				2017/18 Draft			
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	683	675	-501	0.69	683	923	-668	0.75
2	Southern Scotland	3,272	3,339	714	1.64	3,070	3,109	642	1.76
3	Northern	2,609	2,272	617	1.12	2,609	2,267	314	1.29
4	North West	3,504	4,030	1,422	1.91	3,504	3,854	1,175	2.06
5	Yorkshire	4,651	3,688	1,334	1.75	4,651	3,566	1,107	1.85
6	N Wales & Mersey	2,688	2,457	623	1.22	2,688	2,350	520	1.30
7	East Midlands	5,137	4,574	1,597	2.15	5,137	4,360	1,456	2.23
8	Midlands	4,498	4,314	1,754	1.92	4,498	4,125	1,400	2.10
9	Eastern	5,850	6,093	1,818	3.04	5,850	6,036	1,473	3.19
10	South Wales	1,968	1,725	653	0.81	1,968	1,657	554	0.87
11	South East	3,626	3,487	1,108	1.82	3,626	3,711	870	2.00
12	London	5,317	4,779	2,470	1.80	5,317	4,112	2,194	1.93
13	Southern	5,549	5,335	2,095	2.51	5,936	5,179	1,650	2.68
14	South Western	2,604	2,334	703	1.23	2,604	2,436	540	1.32
Total		51,956	49,101	16,407	23.61	52,141	47,684	13,227	25.31

Appendix D : 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 will be updated for the Final Tariffs in January following feedback received from customers. The deadline for responding to the draft ALF document is Friday 6 January 2017.

Table 25: Specific Annual Load Factors

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
			2011	2012	2013	2014	2015	2011	2012	2013	2014	2015	
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%**
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%**
CARRINGTON	CCGT_CHP		Generic	Generic	Generic	Generic	Actual	0.0000%	0.0000%	0.0000%	0.0000%	0.0109%	**25.9594%**
CLUNIE SCHEME	Hydro		Actual	Actual	Actual	Actual	Actual	50.3272%	33.4563%	45.3256%	43.2488%	47.9711%	**45.5152%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
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%**
FERRYBRIDGE B	Coal	Yes	Actual	Actual	Actual	Actual	Actual	50.2631%	59.1851%	48.8918%	25.1499%	23.6444%	**41.4349%**
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%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
FINLARIG	Hydro	Yes	Actual	Actual	Actual	Actual	Actual	67.9805%	40.2952%	59.9142%	59.4092%	65.1349%	**61.4861%**
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%**
LANGAGE	CCGT_CHP	Yes	Actual	Actual	Actual	Actual	Actual	60.7905%	41.9115%	40.8749%	34.8629%	16.5310%	**39.2164%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
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%**
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%	27.2412%	20.2103%	29.2663%	**25.5726%**
LONDON ARRAY	Offshore_Wind	Yes	Generic	Partial	Actual	Actual	Actual	0.0000%	38.0987%	51.2703%	64.0880%	66.8682%	**60.7422%**
LONGANNET	Coal	Yes	Actual	Actual	Actual	Actual	Actual	47.9712%	52.1025%	56.8761%	56.4764%	48.8989%	**52.4926%**
LYNEMOUTH	Coal		Generic	Generic	Generic	Generic	Partial	0.0000%	0.0000%	0.0000%	0.0000%	68.2454%	**60.9881%**
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%	48.4264%	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%	4.1032%	**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%**
RUGELEY B	Coal	Yes	Actual	Actual	Actual	Actual	Actual	53.2455%	68.6109%	82.6505%	59.4472%	44.5189%	**60.4345%**
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	19.2859%	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%**

Power Station	Technology	Generic Station	Yearly Load Factor Source					Yearly Load Factor Value					Specific ALF
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%**
SUTTON BRIDGE	CCGT_CHP		Actual	Actual	Actual	Actual	Actual	64.8794%	20.1652%	9.4124%	17.2025%	13.1999%	**16.8559%**
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		Actual	Actual	Actual	Partial	Actual	19.2655%	45.1938%	38.9899%	46.4198%	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%	54.0202%	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%	20.6382%	30.3021%	46.8421%	59.3477%	**45.4973%**
WEST OF DUDDON SANDS OFFSHORE WIND FARM	Offshore_Wind		Generic	Generic	Partial	Actual	Partial	0.0000%	0.0000%	39.2722%	40.0506%	47.5520%	**42.2916%**
WESTERMOST ROUGH	Offshore_Wind		Generic	Generic	Generic	Partial	Actual	0.0000%	0.0000%	0.0000%	26.6918%	54.8014%	**43.1621%**
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	26.8490%	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 26: Generic Annual Load Factors

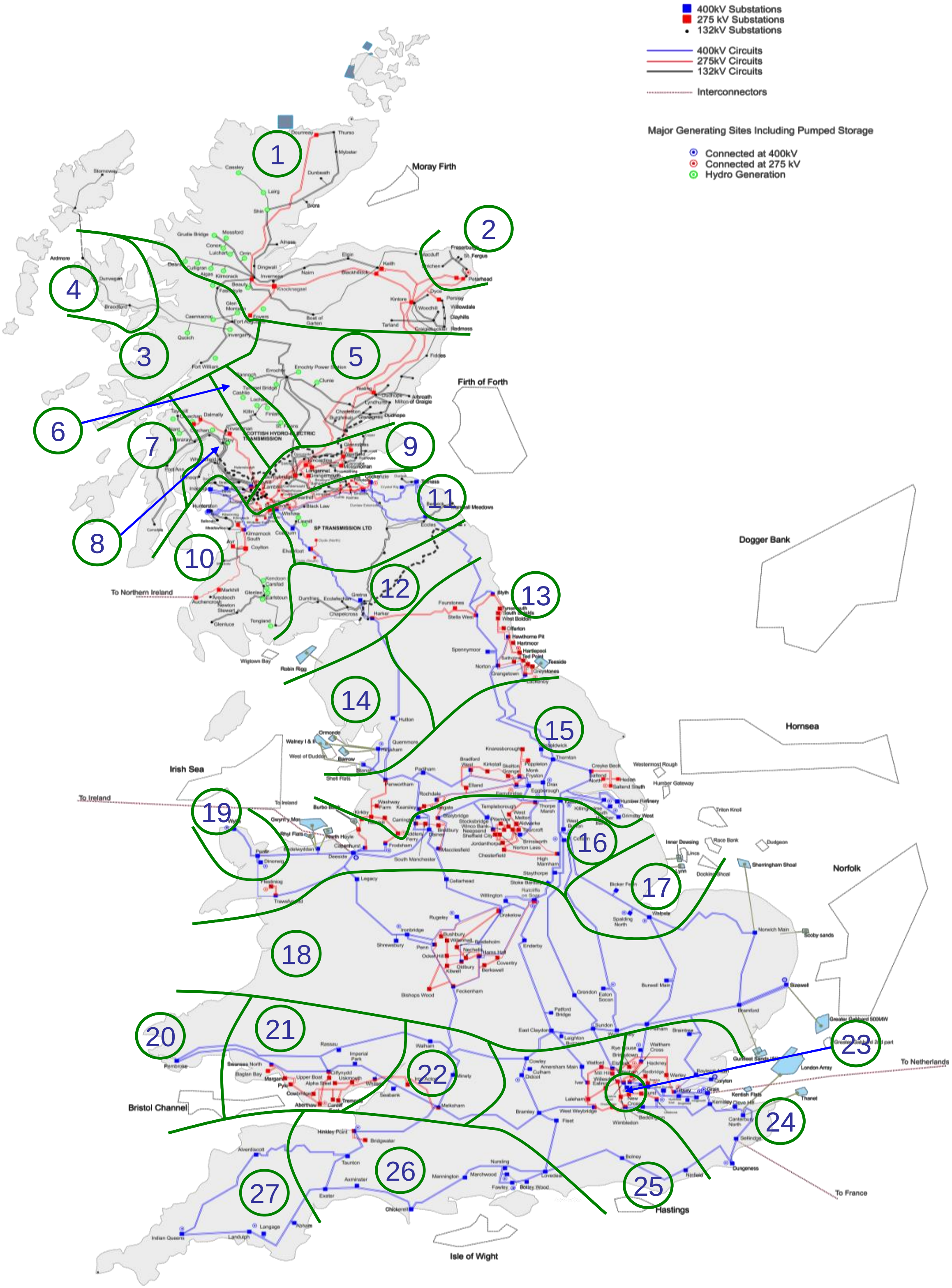
Technology	Generic ALF
Gas_Oil	0.1645%
Pumped_Storage	10.5704%
Tidal*	18.9000%
Biomass	26.8847%
Wave*	31.0000%
Onshore_Wind	37.8084%
CCGT_CHP	38.9336%
Hydro	44.3345%
Offshore_Wind	47.9931%
Coal	57.3594%
Nuclear	75.6256%

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

Table 27 – 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	47.98	0.65	30.40
2	Southern Scotland	0.02	-17.36	47.98	0.65	31.30
3	Northern	-2.67	-5.92	47.98	0.65	40.04
4	North West	-0.71	-1.85	47.98	0.65	46.07
5	Yorkshire	-2.58	-0.27	47.98	0.65	45.79
6	N Wales & Mersey	-1.82	0.79	47.98	0.65	47.61
7	East Midlands	-2.13	2.21	47.98	0.65	48.71
8	Midlands	-1.41	3.05	47.98	0.65	50.28
9	Eastern	1.04	0.76	47.98	0.65	50.44
10	South Wales	-6.19	3.92	47.98	0.65	46.37
11	South East	3.86	0.87	47.98	0.65	53.36
12	London	5.05	2.11	47.98	0.65	55.79
13	Southern	1.68	3.91	47.98	0.65	54.23
14	South Western	-0.93	5.08	47.98	0.65	52.78

Appendix F : Generation Zones



Appendix G : Demand Zones