

October 2016 forecast of TNUoS tariffs for 2017/18

This information paper provides National Grid's forecast of Transmission Network Use of System (TNUoS) tariffs for 2017/18, which apply to Generators and Suppliers. It is the third of a series of updates that National Grid will publish throughout the year.

National Grid will be hosting a webinar on this report on Thursday 3rd November at 13:15.

31 October 2016

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Any Questions?

Contact: Mary Owen,
Kathy Heard, Katharine
Clench, Jo Zhou or Tom
Selby



mary.owen@nationalgrid.com

kathryn.heard@nationalgrid.com

katharine.clench@nationalgrid.com

jo.zhou@nationalgrid.com

thomas.selby@nationalgrid.com



Mary 01926 653845

Kathy 01926 656281

Katharine 01926 656036

Tom 01926 656450

Jo 01926 654184

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1 Executive Summary

Welcome to our October forecast of TNUoS tariffs for 2017/18. This is our third forecast of 2017/18 charges this year and precedes publication of the draft tariffs in December 2016 and final tariffs in January 2017.

Changes to this tariff forecast have predominantly been influenced by changes to generation and Transmission Owner (TO) revenue inputs to the charging model. For generation, an updated generation contracted position as at 31st October 2016 has been used in this forecast and has driven changes to locational charges. Whilst this generation input data was not fully available at the time that these tariffs were calculated, the contracted view in September in addition to industry information has been used to forecast this position. More details on this can be found in Section 4.1 of this document.

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%. The intention is that it will remain fixed for the final tariffs and we have received and listened to feedback from industry that stability in this element of the forecast is welcomed. Further details on the error margin can be found in Section 4.2.2.

In terms of the revenue input, estimates of TO revenue include latest forecasts from each of the onshore TOs. The TO revenue input has decreased by £59.6m resulting in a volume weighted average reduction in Half Hourly demand tariffs of £1.25/kW. Offshore TOs have yet to update their revenue forecasts and so any further changes to revenue due to money being gained or lost through OFTO incentives will be reflected in the December draft tariffs. More details on this can be found in Section 4.2.1.

Further charging methodology input variables that will change between this forecast and the draft tariffs in December 2016 are, firstly, our forecast of chargeable demand. Secondly, Annual Load Factors for generation will also be updated prior to the December tariffs to include the latest year of historical data.

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 in 2017/18, some of which are summarised below.

CMP251 and CMP261 relate to EU Regulation 838/2010 and the €2.50/MWh cap on average generation charges. CMP251 proposes to forecast the G/D split using the €2.50/MWh cap (removing the current error margin) and including an ex post reconciliation to recalculate the G/D split once actual exchange rate and generator output data become known. CMP261 relates to charges set in 2015/16, and whether a correction should be made to tariffs.

CMP268 seeks to introduce a new classification of generator called “Conventional Carbon” into the charging methodology. It proposes that each Conventional Carbon generator’s “Year Round Not Shared” element of the tariff be multiplied by its annual load factor (currently multiplied by TEC). All other generator tariff calculations will remain unchanged. There are a limited number of generators whose locational charge will be directly affected by this proposed

modification. However, all generators will be impacted if there is an increase in the residual tariff component resulting from this modification.

CMP266 proposes to remove a perceived blocker to moving meters from being settled on a Non-Half Hourly (NHH) to a Half Hourly (HH) basis. Currently the movement from a liability based on demand usage between the hours of 4-7pm each day of the year to a charge based on usage over the three Triad half hours can cause the overall liability for that meter within the same charging year to be greater than it would have been if they had not migrated.

More details on all of these modifications can be found on the National Grid website* and market participants are advised to take note of their possible implications for tariffs in 2017/18.

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. Our contact details can be found on page 28.

* Please find further information here: <http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/>

2 Tariff Summary

This section summarises the forecast 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 June forecast of 2017/18.

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	1.39	11.60	15.32	-1.89	24.10	18.07
2	East Aberdeenshire	2.20	5.34	15.32	-1.89	19.90	15.56
3	Western Highlands	0.72	9.99	15.32	-1.89	22.14	17.42
4	Skye and Lochalsh	-5.21	9.99	15.10	-1.89	16.00	17.21
5	Eastern Grampian and Tayside	1.00	8.82	14.92	-1.89	21.09	16.56
6	Central Grampian	3.34	10.02	15.80	-1.89	25.26	17.91
7	Argyll	2.36	7.73	24.53	-1.89	31.17	25.73
8	The Trossachs	2.87	7.73	14.01	-1.89	21.17	15.21
9	Stirlingshire and Fife	0.87	3.36	12.29	-1.89	13.95	11.74
10	South West Scotlands	3.38	6.20	13.19	-1.89	19.64	13.78
11	Lothian and Borders	3.21	6.20	7.96	-1.89	14.24	8.55
12	Solway and Cheviot	0.33	3.21	6.67	-1.89	7.67	6.07
13	North East England	3.31	1.98	3.86	-1.89	6.87	2.76
14	North Lancashire and The Lakes	1.65	1.98	3.34	-1.89	4.69	2.25
15	South Lancashire, Yorkshire and Humber	4.01	0.60	0.15	-1.89	2.75	-1.50
16	North Midlands and North Wales	3.60	-0.93		-1.89	0.96	-2.26
17	South Lincolnshire and North Norfolk	2.21	-0.27		-1.89	0.10	-2.00
18	Mid Wales and The Midlands	1.17	-0.13		-1.89	-0.83	-1.94
19	Anglesey and Snowdon	3.73	-1.71		-1.89	0.47	-2.58
20	Pembrokeshire	8.84	-3.94		-1.89	3.79	-3.47
21	South Wales & Gloucester	5.88	-4.06		-1.89	0.74	-3.52
22	Cotswold	2.83	2.11	-6.27	-1.89	-3.64	-7.31
23	Central London	-4.24	2.11	-5.41	-1.89	-9.86	-6.46
24	Essex and Kent	-3.71	2.11		-1.89	-3.91	-1.05
25	Oxfordshire, Surrey and Sussex	-0.86	-2.29		-1.89	-4.58	-2.81
26	Somerset and Wessex	-1.36	-3.92		-1.89	-6.39	-3.46
27	West Devon and Cornwall	0.00	-5.36		-1.89	-6.18	-4.03

Small Generation Discount (£/kW)	-11.178989
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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	5.47	Langage	0.61
An Suidhe	2.82	Brochlock	1.97	Lochay	0.34
Arcleoch	1.91	Dumnaglass	0.59	Luichart	0.53
Baglan Bay	0.70	Edinbane	-6.30	Mark Hill	0.81
Beinneun Wind Farm	1.38	Earlshaugh Wind Farm	3.47	Margree	3.34
Bhlaraidh Wind Farm	0.59	Ewe Hill	1.27	Marchwood	0.35
Black Hill	1.19	Farr Windfarm	2.07	Millennium Wind	1.68
BlackCraig Wind Farm	3.60	Fallago	0.55	Moffat	0.15
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	1.04
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
Corriearth	3.47	Ulzside	9.65	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	Stronelaig	1.33
Crystal Rig	0.47	Harestanes	2.31	Strathy Wind	2.02
Culligran	1.60	Hartlepool	0.55	Wester Dodds	0.79
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		

Table 4 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.45	38.97	0.97
Greater Gabbard	13.97	32.09	0.00
Gunfleet	16.12	14.80	2.77
Gwynt Y Mor	17.01	16.76	0.00
Lincs	13.92	54.50	0.00
London Array	9.48	32.28	0.00
Ormonde	23.03	42.90	0.34
Robin Rigg East	-0.43	28.22	8.75
Robin Rigg West	-0.43	28.22	8.75
Sheringham Shoal	22.25	26.09	0.57
Thanet	16.94	31.57	0.76
Walney 1	19.87	39.58	0.00
Walney 2	19.73	39.93	0.00
West of Duddon Sands	7.67	37.84	0.00
Westermost Rough	16.15	27.32	0.00
Humber Gateway	13.53	30.54	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	29.37	4.98
2	Southern Scotland	30.19	4.83
3	Northern	39.07	5.75
4	North West	44.55	6.08
5	Yorkshire	44.27	5.94
6	N Wales & Mersey	46.50	7.01
7	East Midlands	47.31	6.55
8	Midlands	49.06	6.54
9	Eastern	48.84	6.87
10	South Wales	45.22	5.97
11	South East	51.69	6.75
12	London	54.14	6.95
13	Southern	52.82	6.83
14	South Western	51.61	6.87

These tariffs include a small generators discount revenue recovery of £0.53 /kW and 0.07 p/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.

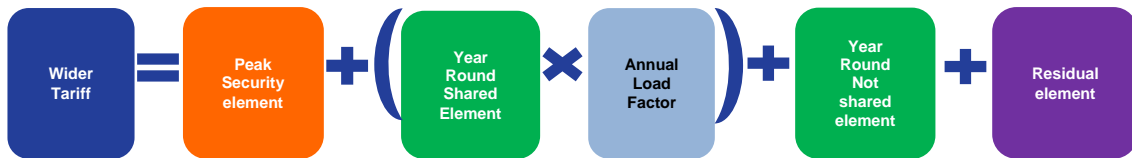
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and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

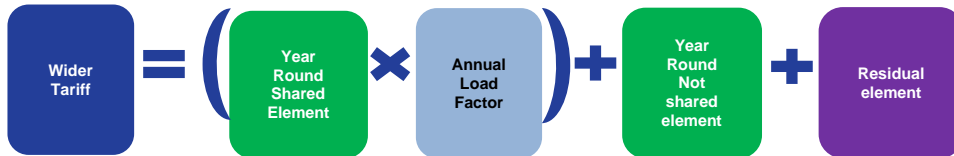
3.2 Charging Principles

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 June we have updated: contracted generation, chargeable generation, directly connected customer demand, circuit and revenue data. There have been no changes to the charging methodology, annual load factors, G/D split or chargeable demand.

4.1 Changes affecting the locational element of tariffs

4.1.1 Forecast Contracted Generation 31st October 2016

We have updated generation for 2017/18 using the contracted generation background as of Sept 2016. On top of this we have altered that contracted position to reflect changes that we expect to happen to the contracted position between the time the tariffs are calculated and 31st October 2016.

The locational element of tariffs will be fixed using the contracted background on 31 October 2016[†]. Table 6 contrasts the contracted generation background in the TEC register with our current view, which is used in this forecast. There has been a significant change since the last update as a result of some TEC changes that were expected to be signed by October 31st are now not expected to be signed until after this date.

Table 6 - Contracted and Modelled TEC

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

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. DNO demand data remains unchanged, however, directly connected customer demand and embedded generation has been updated. Embedded generation could still see changes but these are not expected to be significant.

[†] 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.

4.1.3 Transmission network

Circuit data has been updated within the model for this forecast.

The specific Expansion Factor for the Hunterston – Connah’s Quay HVDC has been updated based upon costs from both NGET and Scottish Power. This has reduced from 6.951964 to 6.754400.

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 expected contracted position of interconnectors on 31st October.

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 increased to £13.588433/MWkm from the initial forecast of £13.550247/MWkm to reflect higher actual RPI compared to that forecast. This has a very small impact on tariffs in all zones, increasing the stretch of the system circuit lengths and so increasing the magnitude of locational tariffs, i.e. positive tariffs more positive and negative tariffs more negative.

Local substation and offshore substation tariffs

Local substation tariffs are increased by RPI as are offshore local circuit tariffs. The change in RPI has been reflected in the tariffs, which show a small increase.

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 data is based upon their latest submission and can be seen in more detail in the appendices. Scottish Power revenue has reduced from the previous forecast by £11.2m. The most significant change is in their MOD licence term. This usually reflects delays to expected construction spend. Scottish Hydro Electric revenue has reduced by £6.3m. This is predominantly as a result of an increase in rates of £20.8, and increase in connection charges of £17.0m (there was no value in the June forecast). The MOD sees a reduction of £44.4m

All TOs are impacted by increases in rates. NGET expect to see an increase of £45m within the rates element of revenue in 19/20 as a result of increased charges in 17/18.

OFTO revenue is based upon their revenue forecasts, where one has been submitted, and our prediction of their revenue when no submission has been made. The forecast revenue for OFTOs has increased by £13.8m with the expectation of further revenue updates from future projects.

The decrease in National Grid revenue of £53.6m is predominantly as a result of there being £59.6m of adjustments for MOD. This reflects changes to the timing of the Hinkley programme and other changes in generation connecting and demand.

Tariffs have been calculated to recover £2,675.6m. This is a reduction of £59.6m from the June forecast of £2,735.1m. All TO's, onshore and offshore are required to submit forecasts of revenue to NGSO by 1st November. This submission will form the basis for the December draft tariffs. The expectation is that there will be limited change when final revenues are submitted for the purposes of final tariffs and invoicing on January 25th.

Table 8 - Allowed revenue

£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						
<i>Price controlled revenue</i>	1,828.2	1,806.4	1,811.2	1,750.4		
<i>Less income from connections</i>	42.7	46.5	46.5	44.1		
Income from TNUoS	1,785.5	1,760.0	1,764.7	1,706.3		
Scottish Power Transmission						
<i>Price controlled revenue</i>	306.4	347.1	341.0	327.7		
<i>Less income from connections</i>	11.8	13.9	14.0	11.4		
Income from TNUoS	294.6	333.1	327.0	316.3		
SHE Transmission						
<i>Price controlled revenue</i>	326.2	328.5	327.3	305.8		
<i>Less income from connections</i>	3.4	3.6	3.6	(13.6)		
Income from TNUoS	322.8	324.9	323.7	319.4		
Offshore	260.8	276.5	279.2	293.0		
Network Innovation Competition	44.9	40.5	40.5	40.5		
Total to Collect from TNUoS	2,708.7	2,735.0	2,735.1	2,675.6		

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

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 49.1GW. Our forecast of Half-Hour metered demand at triad is 16.4GW. The forecast of Non Half Hour demand during 2017/18 is 23.6TWh. This is consistent with the June forecast.

We will seek to update this forecast for the draft tariffs in December

Table 10 - Charging Base

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

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 used the ALFs that were determined last year. The new ALFs, based upon data from 2011/12 - 2015/16 will be calculated prior to the December forecast.

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

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

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)

Z_G , Z_D and 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
R_G	Generator residual tariff (£/kW)	0.51	-0.92	-2.09	-1.89
R_D	Demand residual tariff (£/kW)	45.33	46.34	47.95	46.61
G	Proportion of revenue recovered from generation (%)	16.7%	16.4%	14.3%	14.6%
D	Proportion of revenue recovered from demand (%)	83.3%	83.6%	85.7%	85.4%
R	Total TNUs revenue (£m)	2,709	2,735	2,735	2,676
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	191.9	266.3	275.3	258.9
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-2.4	0.6	-9.7	-3.1
O	Revenue recovered from offshore local tariffs (£m)	200.6	212.9	223.4	225.1
L_G	Revenue recovered from onshore local substation tariffs (£m)	15.9	17.0	17.6	17.6
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.3	15.6	14.0	14.6
B_G	Generator charging base (GW)	62.9	67.3	67.0	66.6
B_D	Demand charging base (GW)	49.8	49.3	49.1	49.1

4.2.6 Small Generators Discount

Table 12 – Small Generator Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-1.89
Demand Residual (£/kW)	D	46.61
Small Generator Discount (£/kW)	$T = (G + D)/4$	11.18
Forecast Small Generator Volume (kW)	V	2,319,260
2017/18 SGD cost (£)	$V \times T$	25,926,982
Prior year reconciliation (£)	R	-
Total SGD Cost (£)	$C = (V \times T) + R$	25,926,982
Total System Triad Demand (kW)	TD	49,100,818
Total HH Triad Demand (kW)	HHD	16,407,205
Total NHH Consumption (kWh)	NHHD	23,613,824,692
Increase in HH Demand tariff (£/kW)	$HHT = C/TD$	0.53
Total Cost to HH Customers (£)	$HHC = HHT * HHD$	8,663,589
Increase in NHH Demand tariff (p/kWh)	$NHHT = (C - HHC)/NHHD$	0.07
Total Cost to NHH Customers (£)	$NHHC = NHHT * NHHD$	17,263,393

The small generators discount has been calculated as £11.18/kW. This equates to a forecast £26m 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.

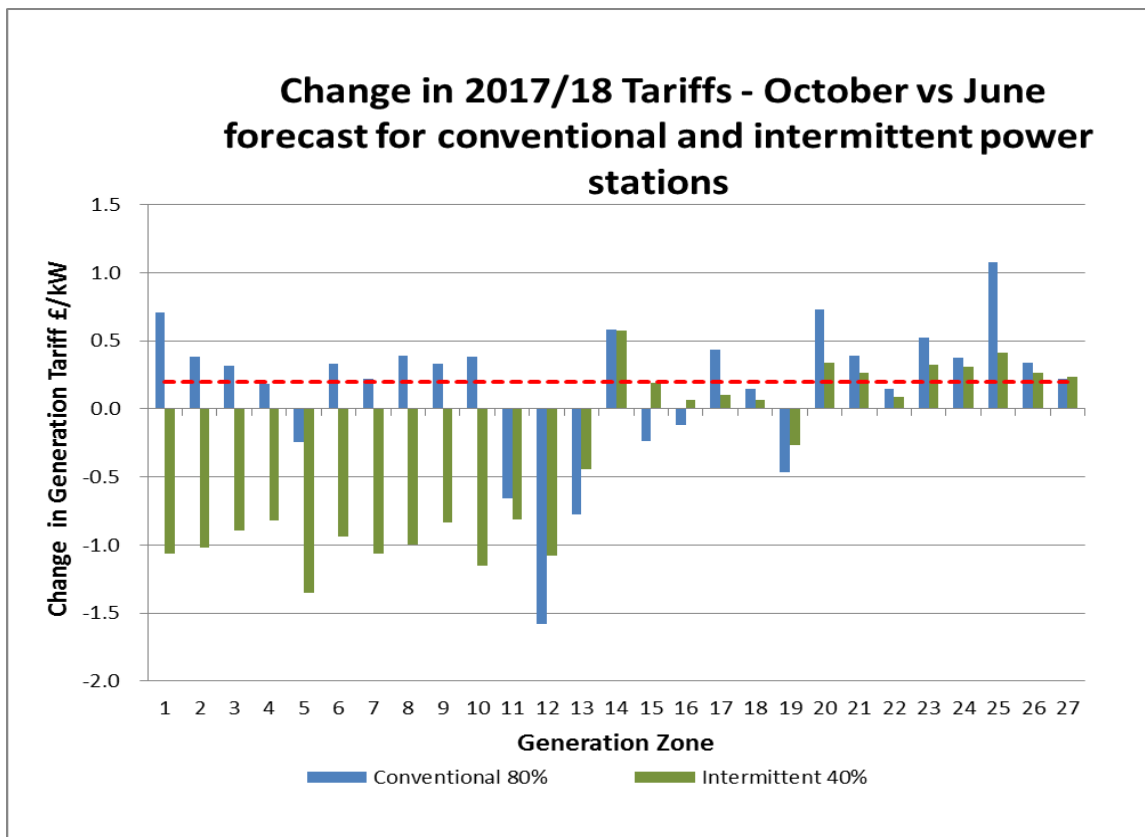
5.1 Wider zonal generation tariffs

Table 13 and Figure 1 show the changes in wider zonal generation TNUoS tariffs between the initial 5 year 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)								
Zone	Zone Name	Conventional 80%			Intermittent 40%			Change in Residual (£/kW)
		2017/18 June Forecast (£/kW)	2017/18 Oct Forecast (£/kW)	Change (£/kW)	2017/18 June Forecast (£/kW)	2017/18 Oct Forecast (£/kW)	Change (£/kW)	
1	North Scotland	23.39	24.10	0.71	19.13	18.07	-1.06	0.20
2	East Aberdeenshire	19.52	19.90	0.39	16.58	15.56	-1.02	0.20
3	Western Highlands	21.82	22.14	0.32	18.32	17.42	-0.89	0.20
4	Skye and Lochalsh	15.82	16.00	0.18	18.02	17.21	-0.82	0.20
5	Eastern Grampian and Tayside	21.33	21.09	-0.24	17.91	16.56	-1.35	0.20
6	Central Grampian	24.93	25.26	0.33	18.85	17.91	-0.94	0.20
7	Argyll	30.95	31.17	0.22	26.79	25.73	-1.06	0.20
8	The Trossachs	20.77	21.17	0.39	16.20	15.21	-0.99	0.20
9	Stirlingshire and Fife	13.62	13.95	0.33	12.57	11.74	-0.83	0.20
10	South West Scotlands	19.25	19.64	0.39	14.93	13.78	-1.15	0.20
11	Lothian and Borders	14.89	14.24	-0.66	9.35	8.55	-0.81	0.20
12	Solway and Cheviot	9.25	7.67	-1.58	7.15	6.07	-1.08	0.20
13	North East England	7.65	6.87	-0.78	3.21	2.76	-0.44	0.20
14	North Lancashire and The Lakes	4.10	4.69	0.59	1.67	2.25	0.58	0.20
15	South Lancashire, Yorkshire and Humber	2.98	2.75	-0.23	-1.70	-1.50	0.19	0.20
16	North Midlands and North Wales	1.08	0.96	-0.12	-2.33	-2.26	0.06	0.20
17	South Lincolnshire and North Norfolk	-0.33	0.10	0.43	-2.10	-2.00	0.10	0.20
18	Mid Wales and The Midlands	-0.97	-0.83	0.14	-2.01	-1.94	0.06	0.20
19	Anglesey and Snowdon	0.93	0.47	-0.47	-2.31	-2.58	-0.27	0.20
20	Pembrokeshire	3.06	3.79	0.73	-3.81	-3.47	0.34	0.20
21	South Wales & Gloucester	0.35	0.74	0.39	-3.78	-3.52	0.27	0.20
22	Cotswold	-3.78	-3.64	0.15	-7.40	-7.31	0.09	0.20
23	Central London	-10.38	-9.86	0.53	-6.79	-6.46	0.33	0.20
24	Essex and Kent	-4.28	-3.91	0.38	-1.35	-1.05	0.31	0.20
25	Oxfordshire, Surrey and Sussex	-5.66	-4.58	1.08	-3.22	-2.81	0.41	0.20
26	Somerset and Wessex	-6.73	-6.39	0.34	-3.72	-3.46	0.26	0.20
27	West Devon and Cornwall	-6.40	-6.18	0.22	-4.27	-4.03	0.24	0.20

Figure 1 - Variation in Generation Zonal Tariffs



Locational Tariff

The locational part of the tariff has changed as a consequence of the changes to predicted contracted TEC Oct 31st.

Some of the generation TEC changes cannot be detailed since the contracts have yet to be signed. We have forecast which of the modification applications that are in progress at present will be signed by Oct 31st. Until they have been signed they are commercially sensitive.

The changes from contracted generation used in the previous forecast are published in the TEC register and are detailed in Appendix B.

An overall reduction in conventional generation in England leads to changes in flows, resulting in some circuits switching from the Year Round to the Peak Security scenario, particularly in Scotland and the north of England. The effect of these changes is a reduction in intermittent tariffs in zones 1 – 13 and a small increase in conventional tariffs in zones 1 – 10 (with the exception of zone 5).

The 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.

There have been a number of circuit changes in and around zones 11-13, which have altered flows on the circuits and resulted in tariff reductions in these zones.

Zone 19 has seen tariff reductions primarily due to flow changes on the Western HVDC link as a result of the overall generation and circuit changes across the whole system.

Residual Tariff

The forecast negative residual element of the tariff has its magnitude decreased by £0.2/kW since our June forecast and average generation charges have increased by £0.03/kW. This small change in tariffs is mainly caused by the generation changes, which have led to an increased proportion of the generation revenue being collected from the locational element of the tariffs.

5.2 Onshore local circuit tariffs

Onshore local circuit tariffs have been updated from the June forecast. Many of the generators that are on spurs will see little change to their tariffs (RPI indexation changes only). Variations from the June forecast are generally caused by changes in flows on surrounding circuits. Circuit data for local circuits will be updated again prior to the Draft tariffs in December. This may effect a change to some local tariffs if a substation is re-categorised from non MITS to MITS or if circuit configurations are different. 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 June forecast to reflect actual RPI, where it is available, and latest forecast RPI.

[‡] 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 June forecast to reflect latest forecast RPI. 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

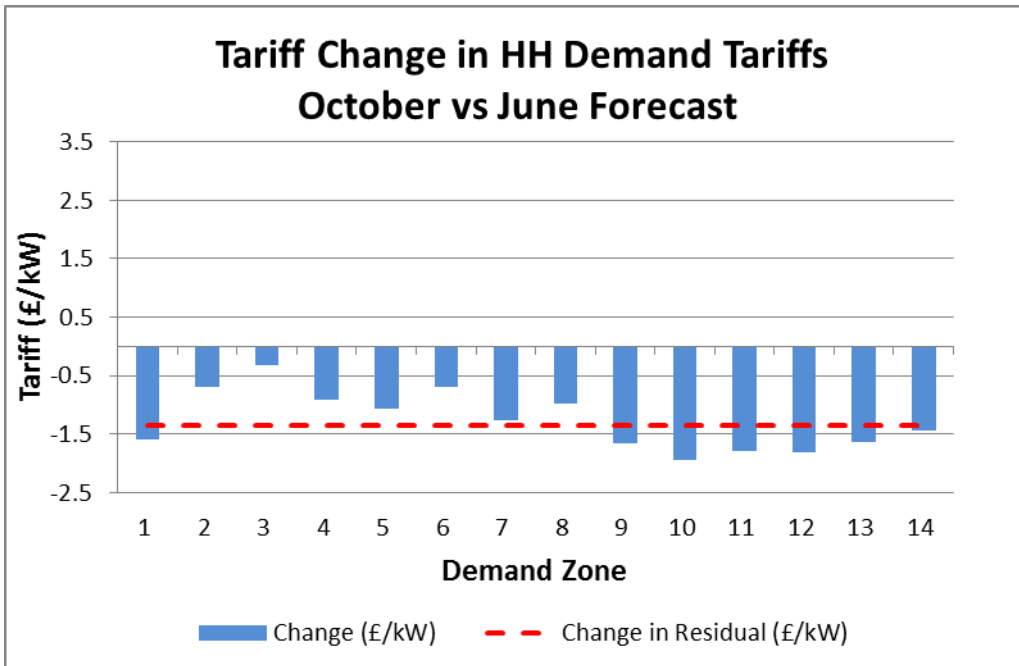
6.1 Half Hour Demand Tariffs

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

Table 15 - Change in HH Demand Tariffs

Zone	Zone Name	2017/18 June (£/kW)	2017/18 Oct (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	30.95	29.37	-1.59	-1.35
2	Southern Scotland	30.88	30.19	-0.69	-1.35
3	Northern	39.40	39.07	-0.33	-1.35
4	North West	45.47	44.55	-0.92	-1.35
5	Yorkshire	45.33	44.27	-1.06	-1.35
6	N Wales & Mersey	47.20	46.50	-0.70	-1.35
7	East Midlands	48.58	47.31	-1.27	-1.35
8	Midlands	50.04	49.06	-0.98	-1.35
9	Eastern	50.50	48.84	-1.66	-1.35
10	South Wales	47.17	45.22	-1.95	-1.35
11	South East	53.47	51.69	-1.79	-1.35
12	London	55.95	54.14	-1.81	-1.35
13	Southern	54.45	52.82	-1.63	-1.35
14	South Western	53.05	51.61	-1.43	-1.35

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.

Residual Tariff

The residual tariff element of HH demand tariffs has decreased by £1.35/kW since the June forecast. The main contributor to this change is the decrease in National Grid revenue of £53.6m, predominantly as a result of £59.6m of adjustments for MOD. This reflects changes to the timing of the Hinkley programme and other changes in generation connecting and demand.

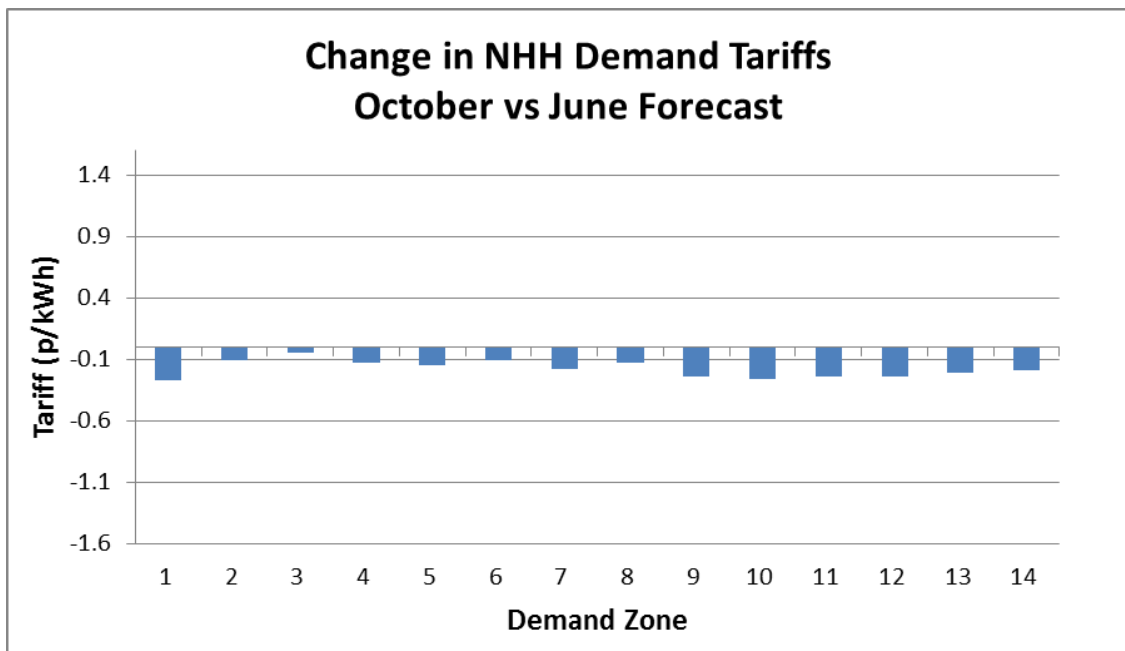
6.2 Non Half-hourly demand tariffs

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

Table 16 - NHH Demand Tariff Changes

Zone	Zone Name	2017/18 June (p/kWh)	2017/18 October (p/kWh)	Change (p/kWh)
1	Northern Scotland	5.25	4.98	-0.27
2	Southern Scotland	4.94	4.83	-0.11
3	Northern	5.79	5.75	-0.05
4	North West	6.20	6.08	-0.13
5	Yorkshire	6.08	5.94	-0.14
6	N Wales & Mersey	7.11	7.01	-0.10
7	East Midlands	6.73	6.55	-0.18
8	Midlands	6.67	6.54	-0.13
9	Eastern	7.11	6.87	-0.23
10	South Wales	6.23	5.97	-0.26
11	South East	6.99	6.75	-0.23
12	London	7.18	6.95	-0.23
13	Southern	7.04	6.83	-0.21
14	South Western	7.06	6.87	-0.19

Figure 3 - NHH Tariff Demand Changes



The forecast weighted average Non Half Hour tariff is 0.17p/kWh lower than in the initial forecast. This is predominantly as a result of the reduction in the residual element of the tariff.

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 Sept 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 changes in the charging base.

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 3rd November 2016 at 13:15 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/>

Team Phone		01926 654633
Katharine Clench	katharine.clench@nationalgrid.com	01926 656036
Mary Owen	mary.owen@nationalgrid.com	01926 653845
Kathy Heard	kathryn.heard@nationalgrid.com	01926 656281
Jo Zhou	jo.zhou@nationalgrid.com	01926 654184
Tom Selby	thomas.selby@nationalgrid.com	01926 656450

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

			01/10/2016				
Description		Licence	Yr t-1	Yr t	Yr t+1		Notes
Regulatory Year			2014/15	2015/16	2016/17	2017/18	
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	1,554.9	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.5	-114.4	-185.4	-250.0	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%	1.7%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	2.8%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	3.0%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	1.2610	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	A	BRt	1732.7	1675.5	1684.4	1605.9	
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	316.3	14/15 & 15/16 & 16/17 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	319.4	14/15 & 15/16 & 16/17 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	293.0	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	935.7	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	4.0	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	8.6	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFit		2.8	2.7	3.0	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	15.6	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.1	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	40.5	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt			0.0	2.0	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	104.9	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	M	Tot	2524.3	2681.6	2751.3	2719.7	
Termination Charges	B5		0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	42.7	44.1	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	T		2477.3	2636.7	2708.7	2675.6	
Final Collected Revenue	U	TNRt	2375.9				Licensee Actual/Forecast
Forecast percentage change to Maximum Revenue M			0.0%	6.2%	2.6%	-1.2%	
Forecast percentage change to TNUoS Collected Revenue T			0.0%	6.4%	2.7%	-1.2%	

Table 20 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast			Updated:		October		Notes
Description	Licence Term	Yr t-1	Yr t	Yr t+1			
		2014/15	2015/16	2016/17			
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%	0.20%		National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	237.0		244.7	249.4	
Price Control Financial Model Iteration Adjustment	A2	MODt	6.2	-20.3	-21.8	-13.5	
RPI True Up	A3	TRUt	-0.1	0.8	-3.9	-5.8	
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327	1.2610	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	A	BRt	292.9	-23.9	270.0	290.1	
Pass-Through Business Rates	B1	RBt	0.0	-20.2	-4.5	-4.7	
Temporary Physical Disconnection	B2	TPDt	0.0	0.0	0.0	0.0	
Pass-Through Items [B=B1+B2]	B	PTt	0.0	-20.2	-4.5	-4.7	
Reliability Incentive Adjustment	C1	RIt	0.0	2.6	3.0	2.9	
Stakeholder Satisfaction Adjustment	C2	SSOt	0.0	1.7	2.1	0.9	
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFit	0.0	-0.2	0.1	0.2	
Awarded Environmental Discretionary Rewards	C4	EDRt	0.0	0.0	0.0	0.5	
Financial Incentive for Timely Connections Output	C5	-CONADJt	0.0	-0.1	0.0	0.0	
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	C	OIPt	0.0	4.0	5.2	4.5	
Network Innovation Allowance	D	NIAt	0.7	1.0	1.0	1.1	
Transmission Investment for Renewable Generation	G	TIRGt	32.2	38.1	31.7	32.8	
Correction Factor	K	-Kt	0.0	-4.9	3.0	3.8	
Maximum Revenue (M= A+B+C+D+G+J+K)	M	TOt	325.8	-5.9	306.4	327.7	
Excluded Services	P	EXCt	7.7	8.0	9.4	11.3	Post BETTA Connection Charges
Site Specific Charges	S	EXSt	18.5	18.8	21.8	22.7	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	T	TSPt	315.0	-16.7	294.0	316.3	General System Charge
Final Collected Revenue	U	TNRt	312.2				
Forecast percentage change to TNUoS Collected Revenue T			0.0%	-105.3%	-1858.9%	7.6%	

Table 21 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast			Updated:	October				Notes
Description	Licence Term		Yr t-1	Yr t	Yr t+1			
			2014/15	2015/16	2016/17	2017/18		
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%	1.13%	National Grid forecast	
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	111.5	124.1	123.6	119.6	From Licence	
Price Control Financial Model Iteration Adjustment	A2	MODt	8.7	85.2	87.6	51.6		
RPI True Up	A3	TRUt	-0.0	0.5	-2.6	-6.1		
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327	1.2610	SHET figures changed to NG forecast so all Tos are consiste	
Base Revenue [A=(A1+A2+A3)*A4]	A	BRt	144.9	257.4	257.2	208.2		
Pass-Through Business Rates	B1	RBt	0.0	-0.7	-16.0	12.2		
Temporary Physical Disconnection	B2	TPDt	0.0	0.6	0.1	0.1		
Pass-Through Items [B=B1+B2]	B	PTt	0.0	-0.1	-15.8	12.3		
Reliability Incentive Adjustment	C1	RIt		1.2	0.2	1.6		
Stakeholder Satisfaction Adjustment	C2	SSOt		1.6	2.3	0.9		
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		-0.3	-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	0.0	0.0		
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	C	OIPt	0.0	2.5	2.3	2.4		
Network Innovation Allowance	D	NIAt	1.3	1.7	1.7	1.4		
Transmission Investment for Renewable Generation	G	TIRGt	72.2	81.3	79.9	83.5		
Compensatory Payments Adjustment	J	SHCPt	0.0	0.4	0.0	0.0		
Correction Factor	K	-Kt		-1.7	0.9	-2.1		
Maximum Revenue (M= A+B+C+D+G+J+K)	M	TOt	218.3	341.5	326.2	305.8		
Excluded Services	P	EXCt	0.0	0.0	0.0	17.0	Post BETTA Connection Charges	
Site Specific Charges	S	EXSt	3.5	3.5	3.5	3.4	Post-Vesting, Pre-BETTA Connection Charges	
TNUoS Collected Revenue (T=M+P+S)	T	TSHt	214.9	338.0	322.7	319.4	General System Charge	
Final Collected Revenue	U	TNRt	217.4	0.0	0.0	0.0		
Forecast percentage change to TNUoS Collected Revenue T			0.0%	57.3%	-4.5%	0.9%		

Table 22 - Offshore Transmission Owner Revenues

Offshore Transmission Revenue Forecast	14/10/2016				Notes
	Description	Yr t-1	Yr t	Yr t+1	
Regulatory Year	2014/15	2015/16	2016/17	2017/18	
Barrow	5.5	5.6	5.7	5.9	
Gunfleet	6.9	7.0	7.1	7.5	
Walney 1	12.5	12.8	12.9	13.1	
Robin Rigg	7.7	7.9	8.0	8.5	
Walney 2	12.9	13.2	12.5	13.6	
Sheringham Shoal	18.9	19.5	19.7	20.0	
Ormonde	11.6	11.8	12.0	12.3	
Greater Gabbard	26.0	26.6	26.9	27.3	
London Array	37.6	39.2	39.5	38.4	
Thanet	78.9	17.5	15.7	17.9	
Lincs		25.6	26.7	27.4	
Gwynt y mor		26.3	23.6	27.0	
West of Duddon Sands			21.3	21.9	
Humber Gateway		35.3	29.3	12.7	Current revenues plus indexation
Westernmost Rough				13.0	
Forecast to asset transfer to OFTO in 2017/18				26.3	National Grid Forecast
Offshore Transmission Pass-Through (B7)	218.4	248.4	260.8	293.0	
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					

Appendix B : Generation changes for 2017/18

Table 23 shows TEC changes notified between June 2016 (used as the basis for the initial forecast) and September 2016 (used for this October forecast.) 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
Barry Power Station	ABTH20	142	21
Clyde North	CLYN2Q	36.7	11
Clyde South	CLYS2R	-54	11
Crookedstane Windfarm	CLYS2R	9.2	11
Dungeness B	DUNG40	10	24
Dunmaglass Wind Farm	DUNM10	-94	1
Earlshaugh Wind Farm	EHAU10	-55	11
Keadby	KEAD40	20	16
Keadby II	KEAD40	-710	16
Kings Lynn A	WALP40_EME	-281	17
Whitelee Extension	WLEX20	-32	10

Appendix C : Locational Demand changes

Table 24 - Demand Profiles

Zone	Zone Name	2017/18 June				2017/18 October			
		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	679	675	-501	0.69	683	675	-501	0.69
2	Southern Scotland	2,968	3,339	714	1.64	3,272	3,339	714	1.64
3	Northern	2,604	2,272	617	1.12	2,609	2,272	617	1.12
4	North West	3,503	4,030	1,422	1.91	3,504	4,030	1,422	1.91
5	Yorkshire	4,650	3,688	1,334	1.75	4,651	3,688	1,334	1.75
6	N Wales & Mersey	2,687	2,457	623	1.22	2,688	2,457	623	1.22
7	East Midlands	5,138	4,574	1,597	2.15	5,137	4,574	1,597	2.15
8	Midlands	4,500	4,314	1,754	1.92	4,498	4,314	1,754	1.92
9	Eastern	5,848	6,093	1,818	3.04	5,850	6,093	1,818	3.04
10	South Wales	1,967	1,725	653	0.81	1,968	1,725	653	0.81
11	South East	3,627	3,487	1,108	1.82	3,626	3,487	1,108	1.82
12	London	5,210	4,779	2,470	1.80	5,317	4,779	2,470	1.80
13	Southern	5,938	5,335	2,095	2.51	5,549	5,335	2,095	2.51
14	South Western	2,604	2,334	703	1.23	2,604	2,334	703	1.23
Total		51,923	49,101	16,407	23.61	51,956	49,101	16,407	23.61

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 2010/11 to 2014/15. Generators which commissioned after 1 April 2012 will have less 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 Draft Tariffs in December using data from charging years 2011/12 to 2015/16.

Table 25: Specific Annual Load Factors

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Aberthaw	Actual	Actual	Actual	Actual	Actual	42.1681%	44.5767%	74.0137%	65.5413%	59.0043%	56.3741%
A'chruach Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Beauly Cascade	Actual	Actual	Actual	Actual	Actual	23.7270%	44.8523%	25.4532%	35.6683%	37.1167%	32.7461%
Aikengall II Windfarm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
An Suidhe Wind Farm	Partial	Actual	Actual	Actual	Actual	27.7229%	34.8406%	31.6380%	41.5843%	36.9422%	37.7890%
Arecleoch	Partial	Actual	Actual	Actual	Actual	28.4997%	35.1282%	32.4826%	33.8296%	29.7298%	33.8135%
Baglan Bay	Actual	Actual	Actual	Actual	Actual	75.0152%	61.0787%	27.5756%	16.4106%	37.9194%	42.1913%
Barrow Offshore Wind Ltd	Generic	Partial	Actual	Actual	Actual	-	51.4133%	42.8840%	54.1080%	47.0231%	48.0051%
Black Law	Actual	Actual	Actual	Actual	Actual	21.8248%	32.5465%	22.0683%	31.9648%	26.7881%	26.9404%
Blacklaw Extension	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Grangemouth	Actual	Actual	Actual	Actual	Actual	66.2697%	67.5783%	52.8594%	55.9047%	62.6168%	61.5971%
Burbo Bank Extension Offshore Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Carraig Gheal	Generic	Generic	Partial	Actual	Actual	-	-	31.8214%	45.2760%	48.9277%	42.0083%
Carrington Power Station	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	41.9008%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Cottam Development Centre	Actual	Actual	Actual	Actual	Actual	63.9771%	46.0664%	13.7361%	16.0249%	31.3132%	31.1348%
Clunie Scheme	Actual	Actual	Actual	Actual	Actual	33.6597%	50.3272%	33.4563%	45.3256%	43.2488%	40.7447%
Clyde (North)	Generic	Partial	Actual	Actual	Actual	-	22.5934%	28.5345%	42.6598%	36.8882%	36.0275%
Clyde (South)	Partial	Actual	Actual	Actual	Actual	23.0513%	21.1154%	31.6084%	39.8941%	29.4115%	33.6380%
Connahs Quay	Actual	Actual	Actual	Actual	Actual	51.0194%	33.6741%	18.5104%	12.8233%	18.3739%	23.5195%
Corby	Actual	Actual	Actual	Actual	Actual	18.2387%	8.1854%	3.4375%	8.0834%	9.6755%	8.6481%
Corriegarth	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Corriemoillie Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Coryton	Actual	Actual	Actual	Actual	Actual	84.0339%	40.7480%	15.6869%	9.7852%	17.5123%	24.6490%
Cottam	Actual	Actual	Actual	Actual	Actual	59.3181%	61.2151%	65.0700%	67.3951%	51.4426%	61.8678%
Cour Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Cruachan	Actual	Actual	Actual	Actual	Actual	11.2970%	8.9462%	8.4281%	9.6969%	9.0516%	9.2315%
Crystal Rig II	Actual	Actual	Actual	Actual	Actual	27.9128%	49.3600%	40.6845%	50.2549%	47.5958%	45.8801%
Beauly Cascade	Actual	Actual	Actual	Actual	Actual	23.7270%	44.8523%	25.4532%	35.6683%	37.1167%	32.7461%
Damhead Creek	Actual	Actual	Actual	Actual	Actual	86.5589%	77.3504%	45.0617%	77.1783%	67.4641%	73.9976%
Beauly Cascade	Actual	Actual	Actual	Actual	Actual	23.7270%	44.8523%	25.4532%	35.6683%	37.1167%	32.7461%
Deeside	Actual	Actual	Actual	Actual	Actual	55.6058%	35.4538%	19.7551%	17.3035%	13.9018%	24.1708%
Dersalloch Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Didcot B	Actual	Actual	Actual	Actual	Actual	73.4424%	56.8079%	49.0134%	18.6624%	25.5345%	43.7853%
Dinorwig	Actual	Actual	Actual	Actual	Actual	15.3082%	15.0985%	15.0990%	15.0898%	15.0650%	15.0958%
Drax	Actual	Actual	Actual	Actual	Actual	82.0455%	81.1523%	82.4774%	80.5151%	82.2149%	81.8042%
Dudgeon Offshore Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Dungeness B	Actual	Actual	Actual	Actual	Actual	39.6373%	11.6712%	59.8295%	61.0068%	54.6917%	51.3862%
Dunlaw Extension	Actual	Actual	Actual	Actual	Actual	34.6421%	37.7664%	32.3771%	34.8226%	30.0797%	33.9472%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Dunmaglass Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Edinbane Wind	Actual	Actual	Actual	Actual	Actual	29.0483%	52.8496%	29.3933%	39.4785%	31.2458%	33.3725%
Brimsgdown	Actual	Actual	Actual	Actual	Actual	57.0990%	39.5562%	21.8759%	18.7645%	11.1229%	26.7322%
Errochty	Actual	Actual	Actual	Actual	Actual	17.0180%	25.1643%	14.5869%	28.2628%	25.3585%	22.5136%
Ewe Hill	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Fallago	Generic	Generic	Partial	Actual	Actual	-	-	34.8914%	54.8683%	44.7267%	44.8288%
Farr Windfarm Tomatin	Actual	Actual	Actual	Actual	Actual	30.4445%	43.3953%	34.0149%	44.7212%	38.5712%	38.6604%
Fasnakyle G1 & G3	Actual	Actual	Actual	Actual	Actual	19.7278%	39.9896%	22.1176%	35.3695%	57.4834%	32.4922%
Fawley CHP	Actual	Actual	Actual	Actual	Actual	69.0226%	71.5686%	61.1362%	63.3619%	72.8484%	67.9844%
Ffestiniog	Actual	Actual	Actual	Actual	Actual	3.0731%	3.3676%	2.9286%	5.4631%	4.3251%	3.5886%
Fiddlers Ferry	Actual	Actual	Actual	Actual	Actual	46.7146%	52.0973%	61.6386%	49.0374%	45.2435%	49.2831%
Finlarig	Actual	Actual	Actual	Actual	Actual	50.0484%	67.9805%	40.2952%	59.9142%	59.4092%	56.4573%
Foyers	Actual	Actual	Actual	Actual	Actual	17.9834%	18.9885%	13.4800%	14.7097%	12.3048%	15.3910%
Freasdail	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Galawhistle Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Galloper Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Glen App Windfarm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Glendoe	Generic	Generic	Actual	Actual	Actual	-	-	17.3350%	36.3802%	32.3494%	28.6882%
Glenmoriston	Actual	Actual	Actual	Actual	Actual	28.3321%	58.0412%	36.3045%	44.4594%	48.7487%	43.1709%
Gordonbush	Generic	Partial	Actual	Actual	Actual	-	32.9384%	37.8930%	46.5594%	47.7981%	44.0835%
Grain	Actual	Actual	Actual	Actual	Actual	18.2091%	29.4910%	25.4580%	41.3833%	44.0031%	32.1108%
Great Yarmouth	Actual	Actual	Actual	Actual	Actual	76.2183%	45.0785%	19.0270%	20.7409%	18.6633%	28.2821%
Greater Gabbard Offshore Wind Farm	Partial	Actual	Actual	Actual	Actual	35.8271%	17.8601%	40.1778%	48.3038%	42.1327%	43.5381%
Griffin Wind	Generic	Partial	Actual	Actual	Actual	-	13.9399%	17.9885%	31.9566%	31.3152%	27.0867%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Gunfleet Sands II	Actual	Actual	Actual	Actual	Actual	41.0784%	41.4244%	45.0132%	52.2361%	44.7211%	43.7196%
Gunfleet Sands I	Actual	Actual	Actual	Actual	Actual	38.1775%	43.7552%	50.1496%	56.6472%	47.0132%	46.9727%
Gwynt y Mor	Generic	Generic	Partial	Actual	Actual	-	-	13.9901%	8.0036%	61.6185%	27.8707%
Hadyard Hill	Actual	Actual	Actual	Actual	Actual	23.8131%	38.9802%	27.6927%	31.9488%	27.7635%	29.1350%
Harestanes	Generic	Generic	Generic	Partial	Actual	-	-	-	23.3480%	28.6355%	29.5726%
Hartlepool	Actual	Actual	Actual	Actual	Actual	79.3759%	71.1712%	80.2632%	73.7557%	56.2803%	74.7676%
Heysham	Actual	Actual	Actual	Actual	Actual	58.1497%	83.7012%	83.3828%	73.3628%	68.8252%	75.1903%
Hinkley Point B	Actual	Actual	Actual	Actual	Actual	65.3580%	56.9291%	61.7582%	68.8664%	70.1411%	65.3275%
Humber Gateway Offshore Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Hunterston	Actual	Actual	Actual	Actual	Actual	73.4059%	75.3474%	73.5984%	84.7953%	79.1368%	76.0275%
Immingham	Actual	Actual	Actual	Actual	Actual	55.5560%	73.3041%	50.1793%	37.8219%	56.8316%	54.1890%
Indian Queens	Actual	Actual	Actual	Actual	Actual	0.7122%	1.3382%	0.3423%	0.2321%	0.0876%	0.4289%
Garry Cascade	Actual	Actual	Actual	Actual	Actual	32.5155%	70.4039%	48.5993%	55.9308%	64.3828%	56.3043%
Keadby II	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	41.9008%
Keith Hill wind farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Kilbraur	Actual	Actual	Actual	Actual	Actual	35.3544%	45.1817%	45.2306%	51.3777%	54.3550%	47.2633%
Kilgallioch	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Beaully Cascade	Actual	Actual	Actual	Actual	Actual	23.7270%	44.8523%	25.4532%	35.6683%	37.1167%	32.7461%
Kings Lynn A	Generic	Generic	Generic	Actual	Actual	-	-	-	0.0000%	0.0000%	13.9669%
Langage	Actual	Actual	Actual	Actual	Actual	74.0119%	60.7905%	41.9115%	40.8749%	34.8629%	47.8589%
Lincs Wind Farm	Generic	Generic	Partial	Actual	Actual	-	-	19.7548%	46.5987%	43.8178%	36.7238%
Little Barford	Actual	Actual	Actual	Actual	Actual	84.4222%	11.8210%	16.3807%	33.6286%	49.6644%	33.2246%
Killin Cascade	Actual	Actual	Actual	Actual	Actual	25.4645%	53.0410%	32.3429%	45.5356%	44.8205%	40.8997%
Lochluichart	Generic	Generic	Generic	Partial	Actual	-	-	-	26.5290%	20.2103%	27.8246%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
London Array	Generic	Generic	Partial	Actual	Actual	-	-	37.9981%	51.2703%	64.0880%	51.1188%
Conon Cascade	Actual	Actual	Actual	Actual	Actual	42.9004%	62.1102%	47.5286%	54.2820%	55.5287%	52.4464%
Marchwood	Actual	Actual	Actual	Actual	Actual	84.3291%	66.1953%	43.3537%	48.6845%	66.4021%	60.4273%
Mark Hill	Partial	Actual	Actual	Actual	Actual	35.0347%	26.3795%	30.1675%	30.2863%	26.7942%	29.0827%
Medway	Actual	Actual	Actual	Actual	Actual	67.0026%	42.4273%	1.0718%	14.5545%	28.0962%	28.3594%
Millennium	Actual	Actual	Actual	Actual	Actual	32.8403%	47.2065%	42.1318%	52.6618%	53.2636%	47.3334%
Conon Cascade	Actual	Actual	Actual	Actual	Actual	42.9004%	62.1102%	47.5286%	54.2820%	55.5287%	52.4464%
Nant	Actual	Actual	Actual	Actual	Actual	22.6503%	42.4480%	20.8965%	35.5883%	36.4040%	31.5476%
Ormonde	Generic	Generic	Partial	Actual	Actual	-	-	48.3775%	49.6561%	42.8711%	46.9682%
Conon Cascade	Actual	Actual	Actual	Actual	Actual	42.9004%	62.1102%	47.5286%	54.2820%	55.5287%	52.4464%
Pembroke	Generic	Partial	Actual	Actual	Actual	-	32.9605%	61.5434%	60.3928%	67.5346%	63.1569%
Pen Y Cymoedd Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Peterhead	Actual	Actual	Actual	Actual	Actual	52.3771%	66.1917%	31.3766%	41.8811%	0.4858%	41.8783%
Pogbie Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Garry Cascade	Actual	Actual	Actual	Actual	Actual	32.5155%	70.4039%	48.5993%	55.9308%	64.3828%	56.3043%
Race Bank Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Rampion Offshore Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	47.8149%
Ratcliffe-on-Soar	Actual	Actual	Actual	Actual	Actual	53.1708%	53.5677%	66.7461%	71.7403%	56.1767%	58.8302%
Robin Rigg East	Partial	Actual	Actual	Actual	Actual	46.3985%	41.4118%	37.4157%	46.7562%	55.3209%	47.8296%
Robin Rigg West	Partial	Actual	Actual	Actual	Actual	46.5006%	44.4918%	38.2254%	48.0629%	53.4150%	48.6565%
Rocksavage	Actual	Actual	Actual	Actual	Actual	55.9818%	47.7376%	41.4820%	2.6155%	4.4252%	31.2149%
Rugeley B	Actual	Actual	Actual	Actual	Actual	50.2059%	53.2455%	68.6109%	82.6505%	59.4472%	60.4345%
Rye House	Actual	Actual	Actual	Actual	Actual	40.3688%	20.4253%	10.7188%	7.4695%	5.3701%	12.8712%
Saltend	Actual	Actual	Actual	Actual	Actual	89.0335%	90.6801%	81.5834%	69.0062%	67.9518%	79.8744%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Seabank	Actual	Actual	Actual	Actual	Actual	72.4476%	34.5669%	15.2311%	18.2781%	25.6956%	26.1802%
Sellafield	Actual	Actual	Actual	Actual	Actual	18.9905%	4.1046%	14.0549%	25.0221%	18.9719%	17.3391%
Severn Power	Partial	Actual	Actual	Actual	Actual	53.7190%	32.2421%	27.7976%	32.4163%	24.6354%	30.8187%
Sheringham Shoal	Generic	Partial	Actual	Actual	Actual	-	19.2221%	36.6431%	49.3517%	46.2286%	44.0744%
Shoreham	Actual	Actual	Generic	Actual	Actual	70.9592%	65.7100%	-	20.7501%	10.2239%	52.4731%
Sizewell B	Actual	Actual	Actual	Actual	Actual	49.0352%	77.3818%	96.7260%	82.5051%	84.7924%	81.5598%
Sloy G2 & G3	Actual	Actual	Actual	Actual	Actual	9.0965%	15.0995%	9.1252%	14.3471%	15.5941%	12.8573%
South Humber bank	Actual	Actual	Actual	Actual	Actual	70.2595%	33.8760%	27.9763%	24.3373%	34.4673%	32.1065%
Spalding	Actual	Actual	Actual	Actual	Actual	63.5046%	65.1849%	34.6976%	33.4800%	39.3092%	45.8371%
Staythorpe	Actual	Actual	Actual	Actual	Actual	51.3069%	58.4594%	54.4117%	37.6216%	56.6148%	54.1112%
Strathy North and South Wind	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%
Sutton Bridge	Actual	Actual	Actual	Actual	Actual	34.5042%	64.8794%	20.1652%	9.4124%	17.2025%	23.9573%
Taylors Lane	Actual	Actual	Actual	Actual	Actual	0.3131%	0.1048%	0.2037%	0.0483%	0.0640%	0.1242%
Tees Renewable Energy Plant	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	28.3185%
Thanet Offshore Wind farm	Partial	Actual	Actual	Actual	Partial	32.8506%	32.4868%	41.1093%	39.7489%	34.8883%	37.7817%
Toddleburn	Actual	Actual	Actual	Actual	Actual	28.9787%	38.1923%	32.7175%	39.5374%	33.7211%	34.8770%
Torness	Actual	Actual	Actual	Actual	Actual	76.6401%	90.0662%	84.8669%	86.4669%	91.4945%	87.1333%
Uskmouth	Actual	Actual	Actual	Actual	Partial	12.6458%	19.2655%	45.1938%	38.9899%	44.4061%	34.4831%
Walney I	Partial	Actual	Actual	Actual	Actual	38.5646%	45.6003%	44.2799%	57.7046%	52.0555%	51.7868%
Walney II	Generic	Generic	Partial	Actual	Actual	-	-	53.9294%	61.9219%	58.2355%	58.0289%
West Burton	Actual	Actual	Actual	Actual	Actual	38.2764%	44.5447%	70.5868%	68.9176%	61.5364%	58.3329%
West Burton B	Generic	Generic	Partial	Actual	Actual	-	-	21.1178%	30.3021%	46.8421%	32.7540%
West of Duddon Sands Offshore Wind Farm	Generic	Generic	Generic	Partial	Actual	-	-	-	39.1340%	40.0506%	42.3332%
Westermost Rough	Generic	Generic	Generic	Generic	Partial	-	-	-	-	26.6225%	40.7508%

Power Station	2010/11 Data	2011/12 Data	2012/13 Data	2013/14 Data	2014/15 Data	2010/11 Load Factor	2011/12 Load Factor	2012/13 Load Factor	2013/14 Load Factor	2014/15 Load Factor	ALF
Whitelee	Actual	Actual	Actual	Actual	Actual	24.7528%	31.7670%	28.2265%	35.1074%	29.8105%	29.9346%
Whitelee Extension	Generic	Partial	Actual	Actual	Actual	-	26.0889%	12.4146%	27.0102%	27.7787%	22.4011%
Wilton	Actual	Actual	Actual	Actual	Actual	11.7767%	12.6949%	3.4258%	4.4941%	21.5867%	9.6552%
Windy Standard II (Brockloch Rig 1) Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%

Table 26: Generic Annual Load Factors

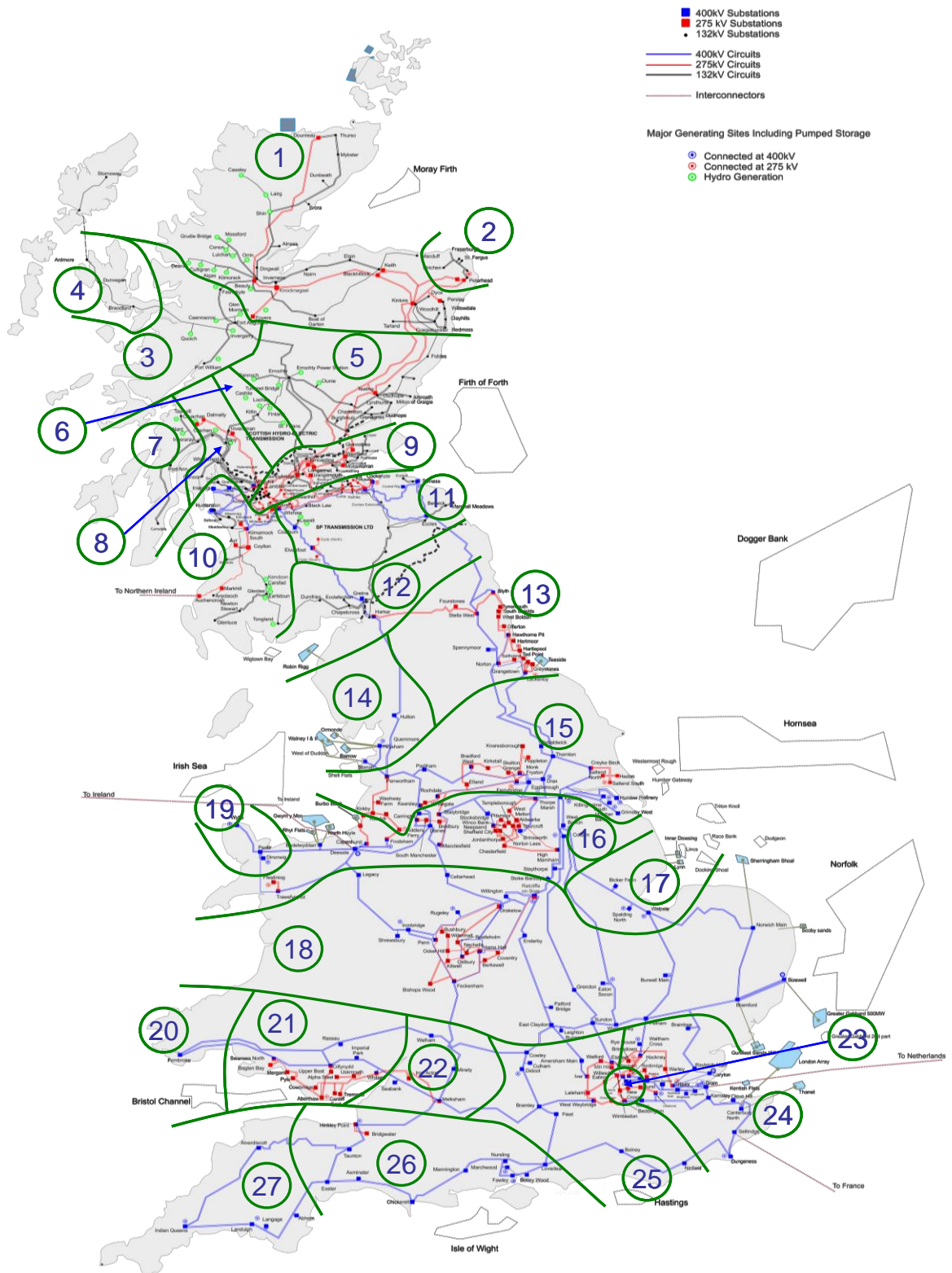
Technology	Generic ALF
Oil_and_OCGT	1.3319%
Pumped_Storage	10.8267%
Hydro	38.5139%
Onshore_Wind	36.7344%
Offshore_Wind	47.8149%
Coal	54.7988%
CCGT_and_CHP	41.9008%
Nuclear	74.2383%
Biomass	28.3185%

Appendix E : Demand tariffs

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	0.49	-18.26	46.61	0.53	29.37
2	Southern Scotland	-0.86	-16.08	46.61	0.53	30.19
3	Northern	-2.70	-5.36	46.61	0.53	39.07
4	North West	-0.71	-1.87	46.61	0.53	44.55
5	Yorkshire	-2.59	-0.28	46.61	0.53	44.27
6	N Wales & Mersey	-1.38	0.75	46.61	0.53	46.50
7	East Midlands	-2.02	2.20	46.61	0.53	47.31
8	Midlands	-1.15	3.07	46.61	0.53	49.06
9	Eastern	1.03	0.67	46.61	0.53	48.84
10	South Wales	-5.93	4.02	46.61	0.53	45.22
11	South East	3.83	0.73	46.61	0.53	51.69
12	London	5.02	1.99	46.61	0.53	54.14
13	Southern	1.84	3.84	46.61	0.53	52.82
14	South Western	-0.69	5.17	46.61	0.53	51.61

Appendix F : Generation Zones



Appendix G : Demand Zones

