nationalgrid

Tariff Information Paper

June 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 second of a series of updates that National Grid will publish throughout the year.

National Grid will be hosting a webinar on this report on Tuesday 5th July 2015 at 1:30pm.

30 June 2016

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Any Questions?

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1 Executive Summary

Welcome to our June forecast of TNUoS tariffs for 2017/18. This is our second forecast of 2017/18 charges this year and as such we recognise it provides a very useful early indication of likely transmission costs for our generation and supply customers and therefore consumers as a whole.

There are two key inputs to our forecast which have influenced these draft tariffs significantly; we felt it was important to incorporate our latest thinking on these two inputs now in order to give an early as possible indication of next year's tariffs.

Firstly, in following the CUSC methodology to calculate the split of revenue to be recovered from generation and demand (the G/D split) we have evolved our thinking on how we establish the Error Margin which has resulted in a figure of 21% which has the effect of increasing the amount of revenue to be recovered from demand users by £60m. More details on this are explained in section 4.2.2.

Secondly, when establishing a forecast of demand use of system for 2017/18 we are required to allocate volumes to the different demand charging zones, the 'zonal split'. This zonal split of demand influences the zonal non-half-hourly demand tariffs and you can see some noticeable swings in the tariffs from our forecast of tariffs published in February. These are explained within section 6.2 of this document.

Earlier in June we hosted a seminar on demand forecasting with our colleagues in National Grid's commercial operations team which explained the processes to establish a demand forecast and the way in which it can influence transmission tariffs. This represents a step change in our approach to stakeholder engagement and we would like to continue with similar sessions as we develop our next forecast of tariffs. Three sessions will be scheduled to ensure that we can discuss with you areas of the methodology such as the Error Margin or demand forecast, and we will share details of the schedule and agenda for these sessions as soon as possible. In the meantime a webinar to present this forecast 1:30pm on Tuesday 5th July at which we would welcome any early thoughts you may have about areas of the methodology on which you would appreciate more information.

In following the current charging methodology within the CUSC please be aware that no current charging modifications are taken account of in these tariffs. A further forecast of tariffs is planned for October and our current schedule of tariff publication requires draft tariffs in December and final 2017/18 tariffs to be published in January.

Do let us know if you have any further requests for how we can better work with you to improve the tariff forecasting process and if you have any questions on this document contact details can be found on page 28.

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 Initial (5 year) 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	-0.72	12.46	16.24	-2.09	23.39	19.13
2	East Aberdeenshire	0.50	6.09	16.24	-2.09	19.52	16.58
3	Western Highlands	-0.72	10.57	16.18	-2.09	21.82	18.32
4	Skye and Lochalsh	-6.44	10.57	15.89	-2.09	15.82	18.02
5	Eastern Grampian and Tayside	-0.60	10.06	15.97	-2.09	21.33	17.91
6	Central Grampian	1.69	10.97	16.55	-2.09	24.93	18.85
7	Argyll	0.75	8.53	25.47	-2.09	30.95	26.79
8	The Trossachs	1.16	8.53	14.88	-2.09	20.77	16.20
9	Stirlingshire and Fife	-0.38	3.59	13.22	-2.09	13.62	12.57
10	South West Scotlands	1.47	7.13	14.17	-2.09	19.25	14.93
11	Lothian and Borders	2.68	7.13	8.59	-2.09	14.89	9.35
12	Solway and Cheviot	0.48	4.07	7.61	-2.09	9.25	7.15
13	North East England	3.41	2.58	4.26	-2.09	7.65	3.21
14	North Lancashire and The Lakes	1.40	2.58	2.73	-2.09	4.10	1.67
15	South Lancashire, Yorkshire and Humber	4.28	0.98	0.00	-2.09	2.98	-1.70
16	North Midlands and North Wales	3.65	-0.60		-2.09	1.08	-2.33
17	South Lincolnshire and North Norfolk	1.78	-0.03		-2.09	-0.33	-2.10
18	Mid Wales and The Midlands	0.96	0.20		-2.09	-0.97	-2.01
19	Anglesey and Snowdon	3.46	-0.55		-2.09	0.93	-2.31
20	Pembrokeshire	8.58	-4.29		-2.09	3.06	-3.81
21	South Wales & Gloucester	5.83	-4.23		-2.09	0.35	-3.78
22	Cotswold	2.89	1.84	-6.05	-2.09	-3.78	-7.40
23	Central London	-4.33	1.84	-5.43	-2.09	-10.38	-6.79
24	Essex and Kent	-3.66	1.84		-2.09	-4.28	-1.35
25	Oxfordshire, Surrey and Sussex	-1.31	-2.82		-2.09	-5.66	-3.22
26	Somerset and Wessex	-1.37	-4.08		-2.09	-6.73	-3.72
27	West Devon and Cornwall	0.05	-5.45		-2.09	-6.40	-4.27

Small Generation Discount (£/kW)	-11.466097

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	5.45	Langage	0.60
An Suidhe	2.80	Brochlock	1.97	Lochay	0.34
Arecleoch	1.91	Dumnaglass	1.70	Luichart	0.53
Baglan Bay	0.64	Edinbane	-6.28	Mark Hill	0.80
Beinneun Wind Farm	1.38	Earlshaugh Wind Farı	3.45	Margree	3.33
Bhlaraidh Wind Farm	0.59	Ewe Hill	1.26	Marchwood	0.35
Black Hill	1.19	Farr Windfarm	2.04	Millennium Wind	1.68
BlackCraig Wind Farm	3.59	Fallago	0.55	Moffat	0.15
Black Law	1.60	Carraig Gheal	4.04	Mossford	2.64
BlackLaw Extension	3.40	Ffestiniogg	0.23	Nant	2.30
Bodelwyddan	0.10	Finlarig	0.29	Necton	-0.35
Carrington	-0.03	Foyers	0.69	Rhigos	0.07
Clyde (North)	0.10	Galawhistle	0.78	Rocksavage	0.02
Clyde (South)	0.12	Glendoe	1.69	Saltend	0.31
Corriegarth	3.46	Ulziside	9.62	South Humber Bank	0.88
Corriemoillie	1.53	Gordonbush	1.08	Spalding	0.25
Coryton	0.05	Griffin Wind	-0.87	Kilbraur	0.72
Cruachan	1.68	Hadyard Hill	2.54	Stronelairg	3.35
Crystal Rig	0.47	Harestanes	2.30	Strathy Wind	2.40
Culligran	1.59	Hartlepool	0.55	West of Duddon	0.78
Deanie	2.61	Hedon	0.17	Whitelee	0.10
Dersalloch	2.21	Invergarry	1.30	Whitelee Extension	0.27
Didcot	0.47	Kilgallioch	0.97		

Table 4 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.43	38.85	0.96
Greater Gabbard	13.92	31.99	0.00
Gunfleet	16.07	14.75	2.76
Gwynt Y Mor	16.95	16.70	0.00
Lincs	13.88	54.33	0.00
London Array	9.45	32.17	0.00
Ormonde	22.95	42.76	0.34
Robin Rigg East	-0.42	28.13	8.72
Robin Rigg West	-0.42	28.13	8.72
Sheringham Shoal	22.18	26.01	0.57
Thanet	16.89	31.47	0.76
Walney 1	19.81	39.45	0.00
Walney 2	19.67	39.80	0.00
West of Duddon Sands	7.64	37.72	0.00
Westermost Rough	16.10	27.23	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	30.95	5.25
2	Southern Scotland	30.88	4.94
3	Northern	39.40	5.79
4	North West	45.47	6.20
5	Yorkshire	45.33	6.08
6	N Wales & Mersey	47.20	7.11
7	East Midlands	48.58	6.73
8	Midlands	50.04	6.67
9	Eastern	50.50	7.11
10	South Wales	47.17	6.23
11	South East	53.47	6.99
12	London	55.95	7.18
13	Southern	54.45	7.04
14	South Western	53.05	7.06

These tariffs include a small generators discount revenue recovery of £0.62 /kW and 0.09 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.

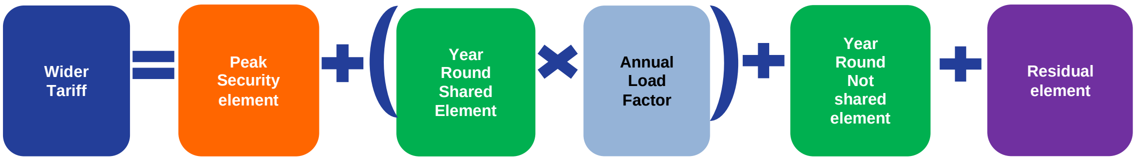
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and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

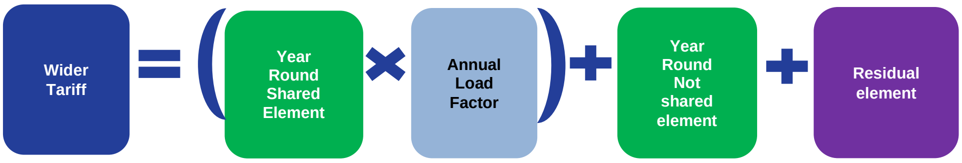
3.2 Charging Principles

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

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 May 2016. On top of this we have altered that contracted position to reflect changes that we expect to happen to the contracted position between now 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. Usually the best view is less than the contracted since the changes we see coming through modification application or forecast are reductions in TEC through delays or closure. Our forecast of contracted TEC for October 31st does include delays, but also includes forecast TEC increases that result in an overall TEC higher than is contracted at present.

Table 6 - Contracted and Modelled TEC

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

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 has been updated and will remain unchanged before tariffs are finalised in January 2017. Directly connected demand and embedded generation will be subject to further revisions.

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* 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 not been updated for this forecast.

The specific Expansion Factor has been included in the transport model for the Hunterston – Crossaig subsea 220kV will be updated in October when the circuit data is updated. At present it reflects the NGET forecast of total cost.

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. The Moyle interconnector at Auchencrosh was incorrectly modelled as 375MW in the initial forecast. This has been rectified and it is now modelled as 80 MW. Note that the table below reflects the contracted position of interconnectors. The best view of interconnector TEC may be different from this if there are delays to projects.

Table 7 - Interconnectors

Interconnector	Site	Interconnected System	Generation Zone	Transport Model Contracted TEC at Peak	Contracted TEC 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 reduced to £13.545/MWkm from the initial forecast of £13.550247 to reflect lower actual RPI compared to that forecast. This has a very small impact on tariffs in all zones, reducing the stretch of the system circuit lengths and so reducing the magnitude of locational tariffs, i.e. positive tariffs less positive and negative tariffs a smaller 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 reduction.

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. The biggest change to Scottish revenue is a reduction in Scottish Power revenue of £6.1m, following a change in their value of Kt.

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 £2.7m.

The increase in National Grid revenue is predominantly as a result of there being £4.9m of adjustments for Scottish Site Specific Charges, an increase in the incentives revenue offset partially by a reduction in the Inter-transmission system operator pass through.

National Grid also collects Network Innovation Competition funding which includes awards for electricity Distribution as well as Transmission.

Tariffs have been calculated to recover £2,735.1m

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						
Price controlled revenue	*1,828.2*	*1,806.4*	*1,811.2*			
Less income from connections	*42.7*	*46.5*	*46.5*			
Income from TNUoS	**1,785.5**	**1,760.0**	**1,764.7**			
Scottish Power Transmission						
Price controlled revenue	*306.4*	*347.1*	*341.0*			
Less income from connections	*11.8*	*13.9*	*14.0*			
Income from TNUoS	**294.6**	**333.1**	**327.0**			
SHE Transmission						
Price controlled revenue	*326.2*	*328.5*	*327.3*			
Less income from connections	*3.4*	*3.6*	*3.6*			
Income from TNUoS	**322.8**	**324.9**	**323.7**			
Offshore	**260.8**	**276.5**	**279.2**			
Network Innovation Competition	**44.9**	**40.5**	**40.5**			
Total to Collect from TNUoS	**2,708.7**	**2,735.0**	**2,735.1**			

4.2.2 Demand: Generation Split

EU Regulation ECR 838/2010 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

Section 14.14.5 (v) of the CUSC establishes the split of revenue between Generation and Demand users in line with the upper limit of a range specified by the EC Regulation 838/2010 to cap the amount payable by generation.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

Where;

Cap_{EC}	=	Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-1

National Grid has continued to follow the calculations of the CMP224 working group which developed the implementation of this EC cap into the CUSC. However, in determining variable 'y', the Error Margin, we have evolved some of our thinking.

We consider that the use of weather corrected out turn data as a comparison to our one year ahead forecast to be artificially lowering the Error Margin percentage. As such, this June forecast of 2017/18 tariffs has been calculated using an Error Margin (y) in this formula which was derived from non-weather corrected data. This latest thinking gives an Error Margin for the 2017/18 tariffs of 21%. If we had used weather corrected data the Error Margin would have been closer to 9%. Each adjustment in the Error Margin varies the amount of revenue we collect from Generators and therefore a 2% increase in the Error Margin would result in a £0.15/kW decrease in the Generator residual and a £0.21/kW increase in the Demand residual.

We are aware that CUSC Modification CMP251 is currently under consideration which, if approved by the Authority, would remove the error margin calculation, target €2.50/MWh as the basis upon which to set the G:D split, and implement an ex post reconciliation. It is unclear whether a decision on CMP251 will have been made by the time of the October forecast of tariffs, and therefore we will be inviting industry to come forward with suggested approaches to the calculation of the error margin.

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
CAP_{EC}	Limit on generation tariff (€/MWh)	2.5	2.5	2.5
y	Error Margin	8.2%	8.2%	21.0%
ER	Exchange Rate (€/£)	1.36	1.34	1.27
MAR	Total Revenue (£m)	2,709	2,735	2,735
GO	Gerneration Output (TWh)	269	263	251
G	% of revenue from generation	17%	16%	14%
D	% of revenue from demand	83%	84%	86%
G.R	Revenue recovered from generation (£m)	453	450	390
D.R	Revenue recovered from demand (£m)	2,255	2,285	2,345

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 has reduced to 49.1GW from an initial forecast of 49.3GW. Our forecast of Half-Hour metered demand at triad has increased from 16.3GW to 16.4GW. The methodology used in this latest forecast is distinctly different to that previously forecast. Both forecasts included an adjustment for P272 migration of demand profile classes 5 to 8 from Non-Half-Hour (NHH) metered to half-Hour (HH) metered.

We have increased our forecast of Non Half Hour demand during 2017/18 from 23.1TWh to 23.6TWh in the June forecast. Once again this forecast was calculated using different models to that used to derive the initial forecast.

Table 10 - Charging Base

Charging Base	2016/17	2017/18 Initial	2017/18 June
Generation (GW)	62.9	67.3	67.0
Total Average Triad (GW)	49.8	49.3	49.1
HH Demand Average Triad (GW)	13.1	16.3	16.4
NHH Demand (4pm-7pm TWh)	26.1	23.1	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
R_G	Generator residual tariff (£/kW)	0.51	0.83	-2.09
R_D	Demand residual tariff (£/kW)	45.33	46.34	47.95
G	Proportion of revenue recovered from generation (%)	16.7%	16.4%	14.3%
D	Proportion of revenue recovered from demand (%)	83.3%	83.6%	85.7%
R	Total TNUoS revenue (£m)	2,709	2,735	2,735
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	191.9	148.2	275.3
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	-2.4	0.6	-9.7
O	Revenue recovered from offshore local tariffs (£m)	200.6	212.9	223.4
L_G	Revenue recovered from onshore local substation tariffs (£m)	15.9	17.0	17.6
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.3	15.6	14.0
B_G	Generator charging base (GW)	62.9	67.3	67.0
B_D	Demand charging base (GW)	49.8	49.3	49.1

4.2.6 Small Generators Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	-2.09
Demand Residual (£/kW)	D	47.95
Small Generator Discount (£/kW)	T = (G + D)/4	11.47
Forecast Small Generator Volume (kW)	V	2,641,010
2017/18 SGD cost (£)	V x T	30,282,077
Prior year reconcilation (£)	R	-
Total SGD Cost (£)	C = (V x T) + R	30,282,077
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	0.62
Total Cost to HH Customers (£)	HHC = HHT * HHD	10,118,859
Increase in NHH Demand tariff (p/kWh)	NHHT = (C - HHC)/NHHD	0.09
Total Cost to NHH Customers (£)	NHHC = NHHT * NHHD	20,163,218

The small generators discount has been calculated as £11.47kW. This equates to a forecast £30m 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.

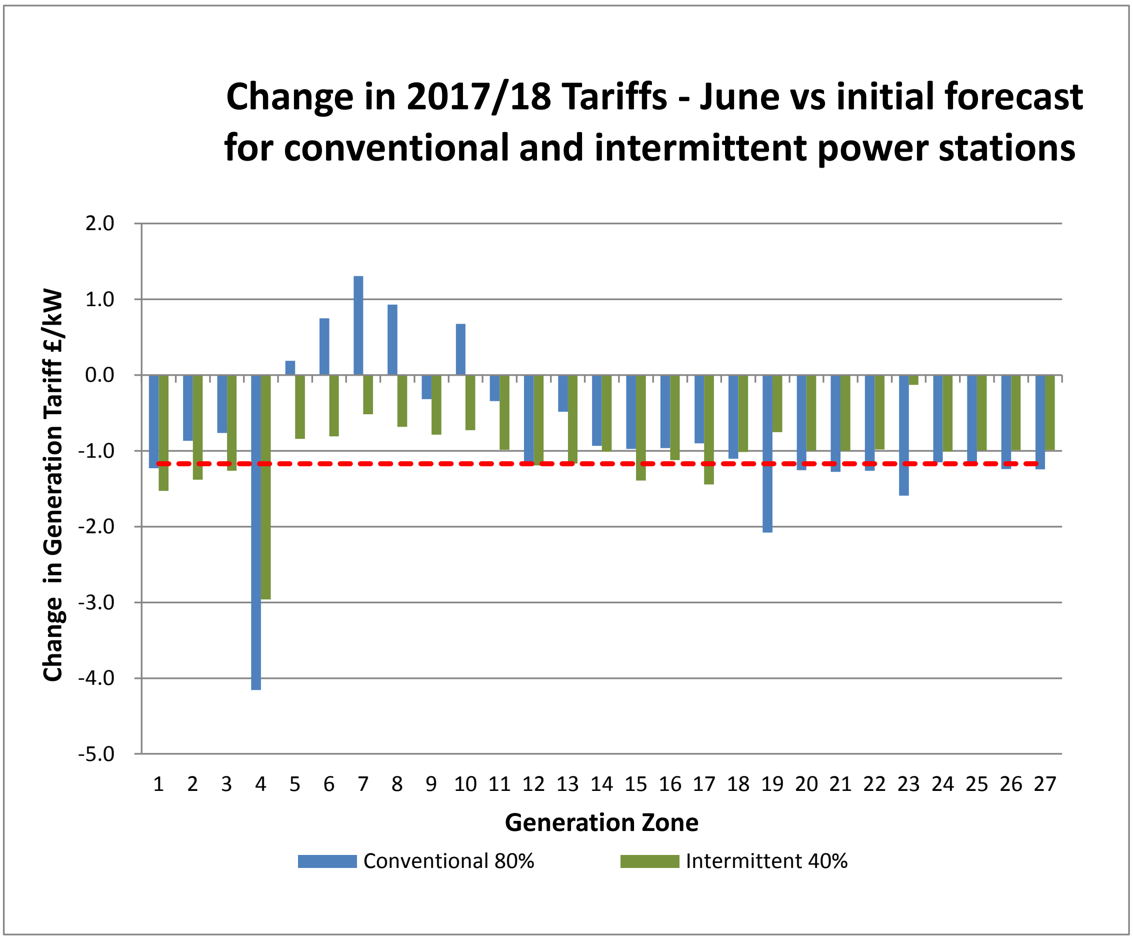
5.1 Wider zonal generation tariffs

Table 12 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 12 – Generation tariff changes

Wider Generation Tariffs (£/kW)								
		Conventional 80%			Intermittent 40%			
Zone	Zone Name	2017/18 Initial Forecast (£/kW)	2017/18 June Forecast (£/kW)	Change (£/kW)	2017/18 Initial Forecast (£/kW)	2017/18 June Forecast (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	North Scotland	24.62	23.39	-1.23	20.66	19.13	-1.53	-1.17
2	East Aberdeenshire	20.38	19.52	-0.87	17.96	16.58	-1.38	-1.17
3	Western Highlands	22.59	21.82	-0.77	19.58	18.32	-1.26	-1.17
4	Skye and Lochalsh	19.98	15.82	-4.16	20.98	18.02	-2.96	-1.17
5	Eastern Grampian and Tayside	21.15	21.33	0.19	18.75	17.91	-0.84	-1.17
6	Central Grampian	24.18	24.93	0.75	19.66	18.85	-0.81	-1.17
7	Argyll	29.64	30.95	1.31	27.31	26.79	-0.52	-1.17
8	The Trossachs	19.84	20.77	0.93	16.88	16.20	-0.68	-1.17
9	Stirlingshire and Fife	13.94	13.62	-0.32	13.36	12.57	-0.79	-1.17
10	South West Scotlands	18.58	19.25	0.67	15.66	14.93	-0.73	-1.17
11	Lothian and Borders	15.23	14.89	-0.34	10.34	9.35	-0.99	-1.17
12	Solway and Cheviot	10.45	9.25	-1.20	8.34	7.15	-1.19	-1.17
13	North East England	8.13	7.65	-0.48	4.37	3.21	-1.17	-1.17
14	North Lancashire and The Lakes	5.04	4.10	-0.93	2.68	1.67	-1.01	-1.17
15	South Lancashire, Yorkshire and Humber	3.95	2.98	-0.98	-0.31	-1.70	-1.39	-1.17
16	North Midlands and North Wales	2.04	1.08	-0.96	-1.21	-2.33	-1.12	-1.17
17	South Lincolnshire and North Norfolk	0.57	-0.33	-0.90	-0.66	-2.10	-1.44	-1.17
18	Mid Wales and The Midlands	0.14	-0.97	-1.10	-0.99	-2.01	-1.01	-1.17
19	Anglesey and Snowdon	3.01	0.93	-2.08	-1.56	-2.31	-0.75	-1.17
20	Pembrokeshire	4.31	3.06	-1.25	-2.81	-3.81	-0.99	-1.17
21	South Wales & Gloucester	1.63	0.35	-1.28	-2.79	-3.78	-1.00	-1.17
22	Cotswold	-2.52	-3.78	-1.26	-6.42	-7.40	-0.98	-1.17
23	Central London	-8.79	-10.38	-1.59	-6.66	-6.79	-0.13	-1.17
24	Essex and Kent	-3.13	-4.28	-1.15	-0.35	-1.35	-1.01	-1.17
25	Oxfordshire, Surrey and Sussex	-4.46	-5.66	-1.20	-2.23	-3.22	-0.99	-1.17
26	Somerset and Wessex	-5.49	-6.73	-1.24	-2.73	-3.72	-0.99	-1.17
27	West Devon and Cornwall	-5.16	-6.40	-1.24	-3.28	-4.27	-0.99	-1.17

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 and with the update to the Week 24 DNO demand forecast

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.

There is only one generator in generation zone 4 and 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 significant demand changes that have resulted in lower tariffs.

Week 24 data has been updated in this forecast and it has had the impact of increasing conventional tariffs (excl. zone 4) and intermittent tariffs in zones 5 - 11. However, the generation changes reduce tariffs, offsetting the increase due to demand in all but zones 5 – 9. Now updated, week 24 data will not change prior to charge setting for 2017/18 tariffs.

Residual Tariff

The forecast residual element of the tariff has decreased by £1.17/kW since our initial forecast and average generation charges have decreased by £0.87/kW. This decrease in tariffs is mainly caused by the recalculation of the Generation/Demand split which reduced the revenue recovered from generation from £450m to £390m.

5.2 Onshore local circuit tariffs

Onshore local circuit tariffs have been updated from the Initial forecast. Many of the generators that are on spurs will see little change to their tariffs (RPI indexation changes only). Variations from the Initial forecast are generally caused by changes in flows on surrounding circuits. Circuit data will be updated prior to the October forecast. 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 13 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 13 - 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 Initial forecast to reflect actual RPI, where it is available, and latest forecast RPI.

5.4 Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) have been updated from the Initial 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.

[†] CUSC section 14.15.12 to 14.15.20

6 Forecast demand tariffs for 2017/18

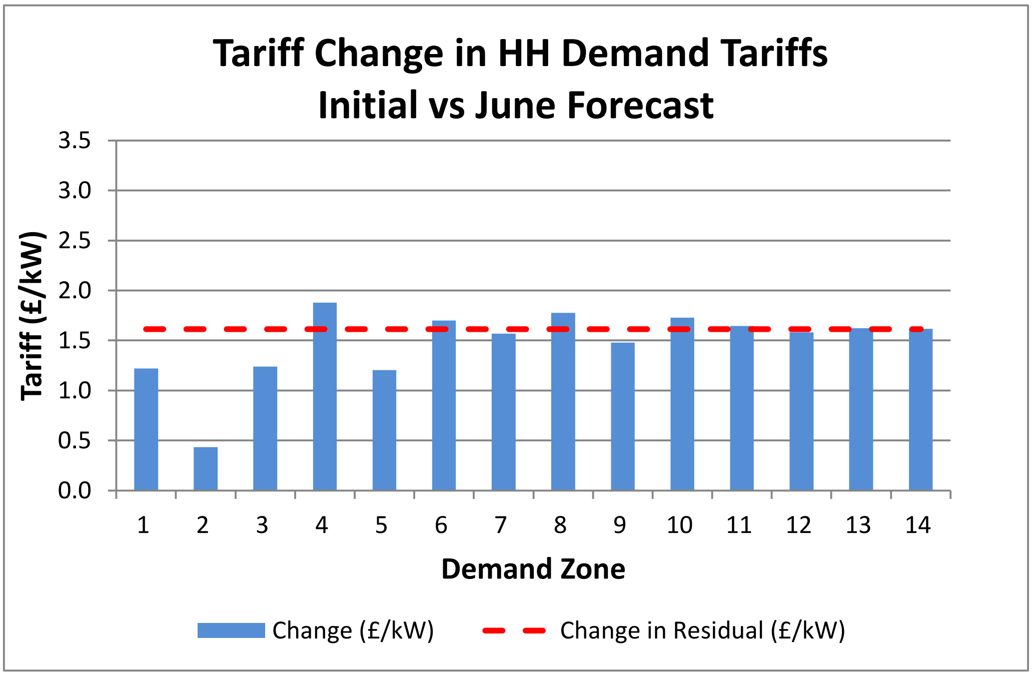
6.1 Half Hour Demand Tariffs

Table 14 and Figure 2 show the difference between the Half-Hourly (HH) demand tariffs forecast in Initial and this June forecast.

Table 14 - Change in HH Demand Tariffs

Zone Name	2017/18 Initial (£/kW)	2017/18 June (£/kW)	Change (£/kW)	Change in Residual (£/kW)
Northern Scotland	29.73	30.95	1.22	1.61
Southern Scotland	30.45	30.88	0.43	1.61
Northern	38.16	39.40	1.24	1.61
North West	43.59	45.47	1.88	1.61
Yorkshire	44.13	45.33	1.20	1.61
N Wales & Mersey	45.50	47.20	1.70	1.61
East Midlands	47.01	48.58	1.57	1.61
Midlands	48.26	50.04	1.78	1.61
Eastern	49.02	50.50	1.48	1.61
South Wales	45.44	47.17	1.73	1.61
South East	51.83	53.47	1.64	1.61
London	54.37	55.95	1.58	1.61
Southern	52.83	54.45	1.62	1.61
South Western	51.43	53.05	1.62	1.61

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. However, Scotland and the north of England have reduced, reflecting changes seen in generation tariffs.

Residual Tariff

The residual tariff element of HH demand tariffs has increased by £1.61/kW since the Initial forecast. There are two main contributors to this change; £0.29/kW of this decrease is due to lower forecast system demand and £1.21/kW is due to the recalculation of the generation/demand split.

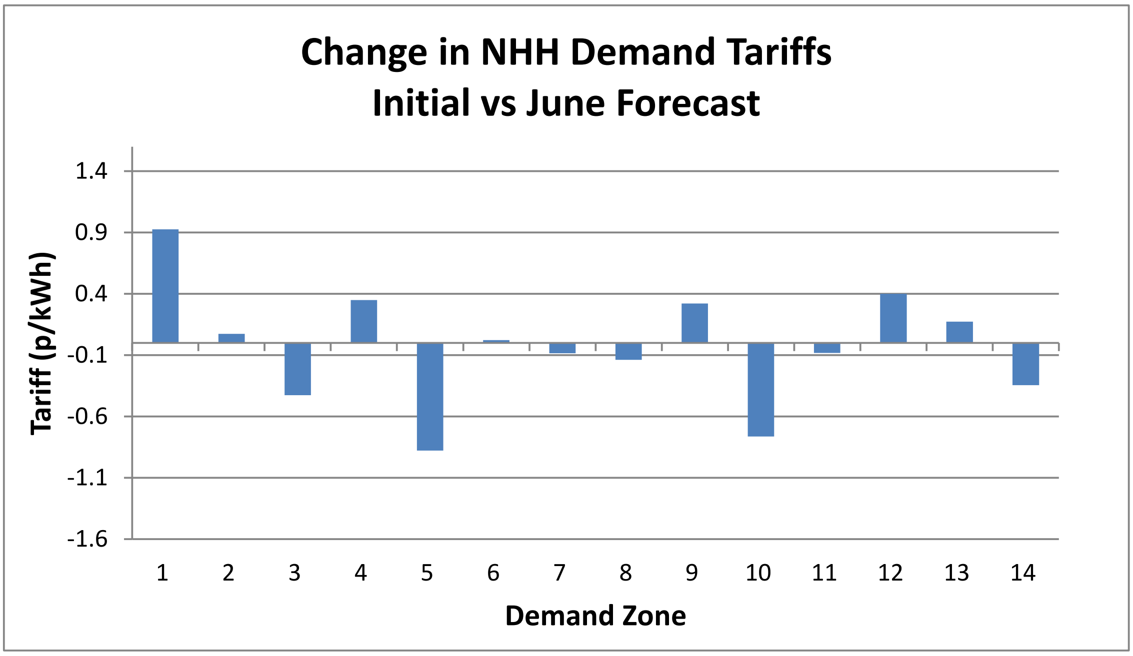
6.2 Non Half-hourly demand tariffs

Table 15 and Figure 3 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in February and this June forecast.

Table 15 - NHH Demand Tariff Changes

Zone	Zone Name	2017/18 Initial (p/kWh)	2017/18 June (p/kWh)	Change (p/kWh)
1	Northern Scotland	4.33	5.25	0.92
2	Southern Scotland	4.87	4.94	0.07
3	Northern	6.22	5.79	-0.43
4	North West	5.85	6.20	0.35
5	Yorkshire	6.96	6.08	-0.88
6	N Wales & Mersey	7.09	7.11	0.02
7	East Midlands	6.81	6.73	-0.09
8	Midlands	6.81	6.67	-0.14
9	Eastern	6.79	7.11	0.32
10	South Wales	6.99	6.23	-0.76
11	South East	7.07	6.99	-0.08
12	London	6.78	7.18	0.40
13	Southern	6.87	7.04	0.17
14	South Western	7.41	7.06	-0.35

Figure 3 - NHH Tariff Demand Changes



The forecast weighted average Non Half Hour tariff is 0.01p/kWh lower than in the initial forecast. This is as a result of a small increase in the forecast of NHH consumption for 2017/18.

Individual NHH tariffs have a greater degree of variation. System demand at peak and HH demands at peak have both been reforecast and these set the revenue to be recovered from each zone. NHH consumption has also been re-forecast, and this determines the cost per unit. Modelled demands can be found in Appendix C.

7 Sensitivities & Uncertainties for 2017/18

7.1 Transmission revenue requirements

Table 16 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 16 – Impact of change in TNUoS Revenue

£50m increase in revenue recovered from TNUoS	
Change in Generation Tariffs (£/kW)	0
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 17 shows the impacts of a 2% increase in system and HH chargeable demand.

Table 17 - 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 1st May 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 Tuesday 5th July 2016 at 1:30pm 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.

We also provide a tariff calculator on the tools and data section of our website to calculate generator tariffs under the CMP213 ('Transmit') methodology.

8.4 Numerical data

All tables in this document can be downloaded as an Excel spreadsheet from our website:

Need the link to where on the website

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Appendices

Appendix A: Revenue Tables

Appendix B: Generation changes for 2017/1

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 18 - National Grid Revenue Forecast

			01/06/2016				
Description		**Licence**	**Yr t-1**	**Yr t**	**Yr t+1**		
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%	1.58%	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	-210.0	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%	2.1%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	3.0%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	3.3%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	1.2680	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**1732.7**	**1675.5**	**1684.4**	**1665.6**	
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	327.0	14/15 & 15/16 & 16/17 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	323.7	14/15 & 15/16 & 16/17 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	279.2	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**	**936.9**	
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**	**15.7**	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	10.5	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	105.5	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**	**2524.3**	**2681.6**	**2751.3**	**2781.6**	
Termination Charges	B5		0.0	0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	42.7	46.5	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**		**2477.3**	**2636.7**	**2708.7**	**2735.1**	
Final Collected Revenue	U	TNRt	2375.9				Licensee Actual/Forecast
Forecast percentage change to Maximum Revenue M			**0.0%**	**6.2%**	**2.6%**	**1.1%**	
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**6.4%**	**2.7%**	**1.0%**	

Table 19 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast			Updated:	07/04/2016			
Description		**Licence Term**	**Yr t-1 2014/15**	**Yr t 2015/16**	**Yr t+1 2016/17**		**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%	1.68%	National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	237.0	258.6	244.7	249.4	
Price Control Financial Model Iteration Adjustment	A2	MODt	6.2	-20.3	-21.8	-4.5	
RPI True Up	A3	TRUt	-0.1	0.8	-3.9	-5.1	
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327	1.2706	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**292.9**	**293.4**	**270.0**	**304.8**	
Pass-Through Business Rates	B1	RBt	0.0	-20.2	-4.5	-4.8	
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**	**-4.8**	
Reliability Incentive Adjustment	C1	RIt	0.0	2.6	3.0	1.2	
Stakeholder Satisfaction Adjustment	C2	SSOt	0.0	1.7	2.1	0.6	
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	0.0	-0.2	0.1	0.0	
Awarded Environmental Discretionary Rewards	C4	EDRt	0.0	0.0	0.0	0.7	
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**	**2.5**	
Network Innovation Allowance	D	NIAt	0.7	1.0	1.0	1.0	
Transmission Investment for Renewable Generation	G	TIRGt	32.2	38.1	31.7	33.0	
Correction Factor	K	-Kt	0.0	-4.9	3.0	5.2	
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**325.8**	**311.3**	**306.4**	**341.7**	
Excluded Services	P	EXCt	7.7	8.0	9.4	11.8	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	18.5	18.8	21.8	25.8	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**	**315.0**	**300.5**	**294.0**	**327.7**	General System Charge
Final Collected Revenue	U	TNRt	312.2				
Forecast percentage change to TNUoS Collected Revenue T			**0.0%**	**-4.6%**	**-2.2%**	**11.4%**	

Table 20 - SHE Transmission Revenue Forecast

Description		Licence Term	Yr t-1 2014/15	Yr t 2015/16	Yr t+1 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%	1.68%	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	84.8	
RPI True Up	A3	TRUt	-0.0	0.5	-2.6	-6.4	
RPI Forecast	A4	RPIFt	1.2051	1.2266	1.2327	1.2760	16/17 RPIF amended to reflect 16/17 Charge Setting, Natio
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**144.9**	**257.4**	**257.2**	**252.6**	
Pass-Through Business Rates	B1	RBt	0.0	-0.7	-16.0	-8.6	
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**	**-8.4**	
Reliability Incentive Adjustment	C1	RIt		1.2	0.2	0.7	
Stakeholder Satisfaction Adjustment	C2	SSOt		1.6	2.3	3.2	
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		-0.3	-0.2	-0.2	
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**	**3.7**	
Network Innovation Allowance	D	NIAt	1.3	1.7	1.7	1.7	
Transmission Investment for Renewable Generation	G	TIRGt	72.2	81.3	79.9	79.7	
Compensatory Payments Adjustment	J	SHCPt	0.0	0.4	0.0	0.0	
Correction Factor	K	-Kt		-1.7	0.9	0.0	
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**	**218.3**	**341.5**	**326.2**	**329.3**	
Excluded Services	P	EXCt	0.0	0.0	0.0	0.0	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt	3.5	3.5	3.5	3.6	Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**	**214.9**	**338.0**	**322.7**	**325.7**	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 21 - Offshore Transmission Owner Revenues

<table>
<tr><th>Offshore Transmission Revenue Forecast</th><th colspan="4">14/06/2016</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></td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>7.5</td><td></td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>13.1</td><td></td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>8.5</td><td></td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>12.5</td><td>13.6</td><td></td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>20.0</td><td></td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>12.3</td><td></td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>27.3</td><td></td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>39.5</td><td>38.4</td><td></td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>15.7</td><td>17.9</td><td></td></tr>
<tr><td>Lincs</td><td>25.6</td><td>26.7</td><td>27.4</td><td></td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>23.6</td><td>26.0</td><td></td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td>21.3</td><td>21.9</td><td></td></tr>
<tr><td>Humber Gateway</td><td></td><td rowspan="2">29.3</td><td>15.7</td><td>National Grid Forecast</td></tr>
<tr><td>Westermost Rough</td><td></td><td>12.5</td><td></td></tr>
<tr><td>Forecast to asset transfer to OFTO in 2017/18</td><td></td><td></td><td></td><td>11.1</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>279.2</td><td></td></tr>
</table>

Appendix B : Generation changes for 2017/18

Table 22 shows TEC changes notified between January 2016 (used as the basis for the initial forecast) and May 2016 (used for this June 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 22 - Generation TEC Changes

Power Station	Node	MW Change	Zone
Aberthaw	ABTH20	-10	21
A'Chruach Wind Farm	ACHR1R	-6.9	7
Afton	BLAC10	-18	10
Beatrice Wind Farm	BLHI40	-20	1
Blacklaw Extension	BLKX10	-9	11
Clyde North	CLYN2Q	-36.7	11
Clyde South	CLYS2R	54	11
Crystal Rig 2	CRYR40	-62	11
Crystal Rig 3	CRYR40	62	11
Drax	DRAX40	-3906	15
Drax (Biomass)	DRAX40	1905	15
Drax (Coal)	DRAX40	2001	15
Harestanes	HARE10	-17.3	12
Keith Hill Wind Farm	DUNE10	0.5	11
Lynemouth Power Station	BLYT20	376	13
Medway Power Station	GRAI40	35	24
Peterborough	WALP40_EME	245	17
Rugeley	RUGE40	-980	18
Taylors Lane	WISD20_LPN	-144	23

Appendix C : Locational Demand changes

Table 23 - Demand Profiles

		2017/18 Initial				2017/18 June			
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	607	551	-380	0.64	679	675	-501	0.69
2	Southern Scotland	3,215	3,114	643	1.54	2,968	3,339	714	1.64
3	Northern	2,590	2,152	332	1.11	2,604	2,272	617	1.12
4	North West	4,032	3,664	1,183	1.85	3,503	4,030	1,422	1.91
5	Yorkshire	4,583	3,839	1,173	1.69	4,650	3,688	1,334	1.75
6	N Wales & Mersey	1,887	2,988	1,170	1.17	2,687	2,457	623	1.22
7	East Midlands	5,077	4,745	1,718	2.09	5,138	4,574	1,597	2.15
8	Midlands	4,422	4,193	1,560	1.87	4,500	4,314	1,754	1.92
9	Eastern	5,650	6,016	1,853	3.01	5,848	6,093	1,818	3.04
10	South Wales	1,921	2,221	1,013	0.78	1,967	1,725	653	0.81
11	South East	3,618	3,599	1,071	1.85	3,627	3,487	1,108	1.82
12	London	4,864	4,406	2,061	1.88	5,210	4,779	2,470	1.80
13	Southern	5,905	5,547	2,324	2.48	5,938	5,335	2,095	2.51
14	South Western	2,711	2,262	580	1.17	2,604	2,334	703	1.23
Total		51,085	49,298	16,300	23.14	51,923	49,101	16,407	23.61

Appendix D : Annual Load Factors

Table 24 lists the Annual Load Factors (ALF) of generators expected to be liable for generator charges during 2016/17. ALF are used to scale the Shared Year Round element of tariffs so each generator has a tariff appropriate to its historical load factor. ALF 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 25 are added to create three complete years from which the ALF can be calculated. Generators expected to commission during 2016/17 also use the Generic ALF.

Table 24 : 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%
Cottam Development Centre	Actual	Actual	Actual	Actual	Actual	63.9771%	46.0664%	13.7361%	16.0249%	31.3132%	31.1348%

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
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%
Dunmaglass Wind Farm	Generic	Generic	Generic	Generic	Generic	-	-	-	-	-	36.7344%

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
Edinbane Wind	Actual	Actual	Actual	Actual	Actual	29.0483%	52.8496%	29.3933%	39.4785%	31.2458%	33.3725%
Brimsdown	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%
Ffestiniogg	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%
Gunfleet Sands II	Actual	Actual	Actual	Actual	Actual	41.0784%	41.4244%	45.0132%	52.2361%	44.7211%	43.7196%

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 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%
Beauly 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%
London Array	Generic	Generic	Partial	Actual	Actual	-	-	37.9981%	51.2703%	64.0880%	51.1188%

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
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%
Seabank	Actual	Actual	Actual	Actual	Actual	72.4476%	34.5669%	15.2311%	18.2781%	25.6956%	26.1802%

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
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%
Whitelee	Actual	Actual	Actual	Actual	Actual	24.7528%	31.7670%	28.2265%	35.1074%	29.8105%	29.9346%

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 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 25 : 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%

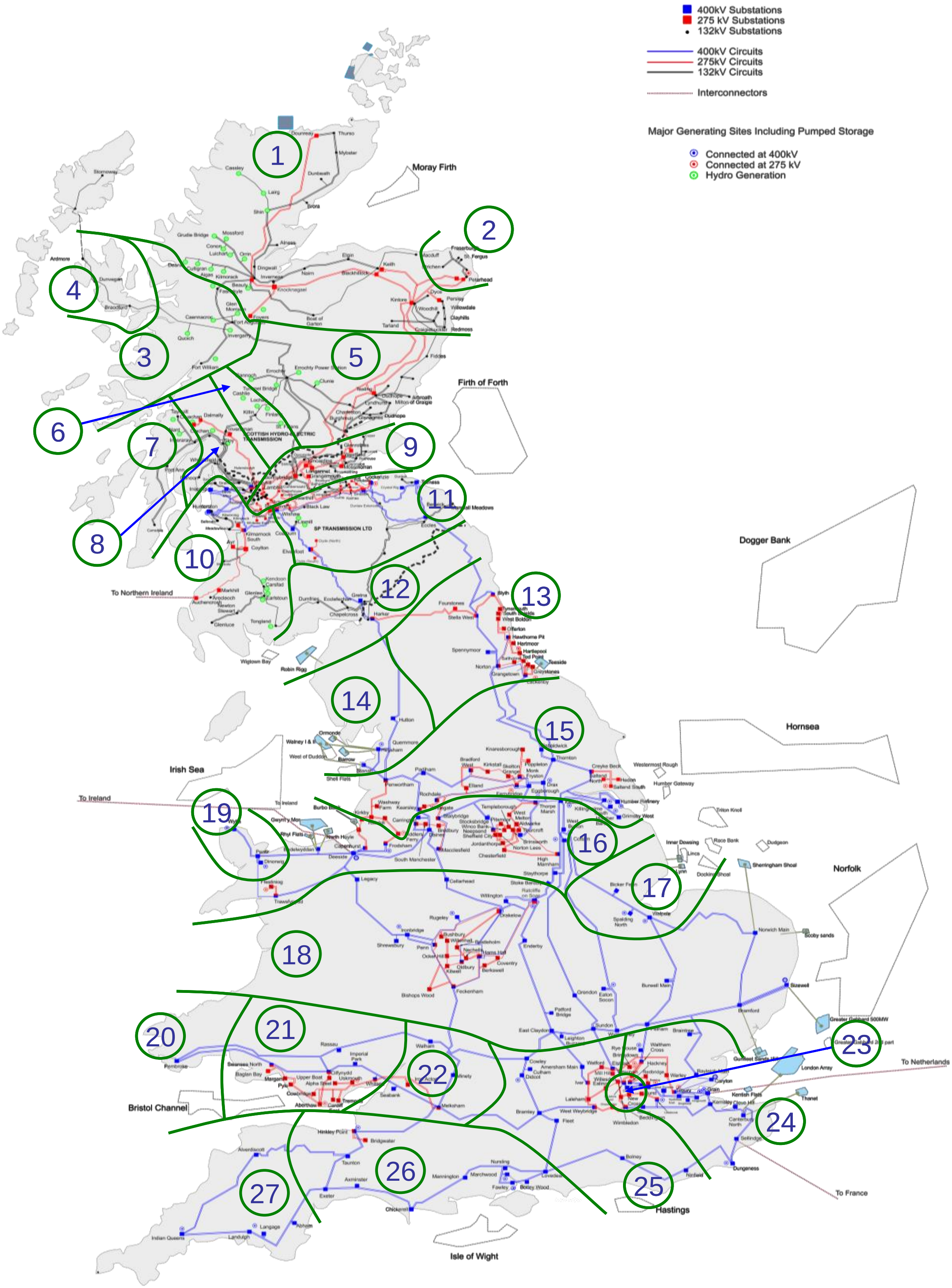
Table 26 : Demand Tariffs including the peak and year round breakdown

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	2.41	-20.02	47.68	0.62	30.67
2	Southern Scotland	0.13	-17.82	47.68	0.62	30.60
3	Northern	-2.93	-6.24	47.68	0.62	39.12
4	North West	-1.17	-1.93	47.68	0.62	45.19
5	Yorkshire	-3.07	-0.17	47.68	0.62	45.05
6	N Wales & Mersey	-1.55	0.18	47.68	0.62	46.92
7	East Midlands	-2.11	2.12	47.68	0.62	48.30
8	Midlands	-1.47	2.93	47.68	0.62	49.76
9	Eastern	1.26	0.67	47.68	0.62	50.22
10	South Wales	-5.69	4.29	47.68	0.62	46.89
11	South East	3.88	1.02	47.68	0.62	53.20
12	London	5.11	2.27	47.68	0.62	55.67
13	Southern	1.80	4.08	47.68	0.62	54.18
14	South Western	-0.76	5.24	47.68	0.62	52.77

Appendix F : Generation Zones



Appendix G : Demand Zones