

Final TNUoS tariffs for 2016/17

This information paper provides National Grid's Transmission Network Use of System (TNUoS) tariffs for 2016/17, which apply to Generators and Suppliers as of 1 April 2016.

29 January 2016

V1.0

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Any Questions?

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1 Executive Summary

This document contains our Final Transmission Network Use of System (TNUOs) tariffs for 2016/17. TNUoS charges are paid by generators and suppliers for use of the GB Transmission networks.

Total revenue recovered from TNUoS charges will be £2,708.7m, an increase of £72m on last year. Generation tariffs have been set to recover £453.4m to ensure average annual generation tariffs remain below the €2.5/MWh limit set by European Commission Regulation (EU) No 838/2010. This is a £158.3m reduction in generation revenue compared to last year, reflecting reductions in forecast generation output and a weaker Euro. Demand tariffs have been set to recover £2,255.2m, an increase of £230.3m on last year. This reflects the above reduction in generation revenue and changes in overall revenue for GB Transmission Owners.

During 2015 National Grid has been improving its demand forecasting capability to model the significant increase in distributed generation in recent years. Further information on the deployment and government incentives for solar PV became available at the end of 2015 which has been incorporated into these tariffs. Consequently we are now forecasting average triad demand of 49.8GW, average Half-Hour (HH) triad demand of 13.1GW and Non-Half-Hour (NHH) demand of 26.1TWh.

To recover allowed revenues, these lower demands mean that the average HH demand tariff has increased by £6.34/kW and the average NHH demand tariff has increased by 1.03p/kWh on last year.

2016/17 is the first year under the new 'Transmit' charging methodology introduced by CUSC Modification Proposal 213 in 2014. This methodology changes the wider tariff paid by generators from a single tariff per zone to four tariffs per zone which are combined according to the technology and load factor of the generator. We have been publishing tariffs under this new structure since late 2013.

Special condition C13 in National Grid's licence allows for a discount to the wider generator tariff for small 132kV connected generators. This condition has been extended to 31 March 2019 by Ofgem and is therefore reflected in these tariffs.

2 Tariff Summary

This section summarises the Final generation and demand tariff forecasts for 2016/17. Information can be found in later sections on how these tariffs were calculated and how they have changed from 2015/16.

2.1 Generation Tariffs 2016/17

Table 1 - Wider Generation Tariffs

Under the Transmit methodology each generator has its own Annual Load Factor (ALF). Final ALFs for 2016/17 can be found in the TNUoS forecast area of our website. The 70% and 30% load factors used in this table are only for illustration.

		System Peak	Shared Year Round	Not Shared Year Round	Residual	Conventional 70%	Intermittent 30%
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	-1.986384	10.510176	7.768442	0.505777	13.644958	11.427272
2	East Aberdeenshire	-0.952272	4.161935	7.768442	0.505777	10.235302	9.522800
3	Western Highlands	-2.066820	8.304164	7.490311	0.505777	11.742183	10.487338
4	Skye and Lochalsh	-6.074463	8.304164	8.960467	0.505777	9.204697	11.957494
5	Eastern Grampian and Tayside	-2.113534	7.474278	7.202335	0.505777	10.826572	9.950395
6	Central Grampian	0.626145	7.731765	7.351421	0.505777	13.895578	10.176728
7	Argyll	-0.466457	5.336084	15.889739	0.505777	19.664317	17.996341
8	The Trossachs	0.107014	5.336084	5.855644	0.505777	10.203694	7.962246
9	Stirlingshire and Fife	-2.125012	2.772336	5.083135	0.505777	5.404536	6.420613
10	South West Scotlands	-0.297439	4.218982	5.408636	0.505777	8.570261	7.180108
11	Lothian and Borders	0.687845	4.218982	3.235162	0.505777	7.382072	5.006634
12	Solway and Cheviot	-0.735829	2.741524	2.971182	0.505777	4.660198	4.299417
13	North East England	0.906080	2.101775	-0.112382	0.505777	2.770717	1.023927
14	North Lancashire and The Lakes	1.099994	2.101775	1.848625	0.505777	4.925639	2.984935
15	South Lancashire, Yorkshire and Humber	4.009302	1.439013	0.096468	0.505777	5.618857	1.033949
16	North Midlands and North Wales	3.876723	0.464195		0.505777	4.707437	0.645036
17	South Lincolnshire and North Norfolk	2.242699	0.598940		0.505777	3.167734	0.685459
18	Mid Wales and The Midlands	1.608898	0.330039		0.505777	2.345703	0.604789
19	Anglesey and Snowdon	4.964300	1.025652		0.505777	6.188033	0.813473
20	Pembrokeshire	9.114937	-2.678251		0.505777	7.745938	-0.297698
21	South Wales & Gloucester	6.245424	-2.648511		0.505777	4.897244	-0.288776
22	Cotswold	3.191385	3.112061	-5.745202	0.505777	0.130403	-4.305807
23	Central London	-2.762197	3.112061	-6.320128	0.505777	-6.398105	-4.880733
24	Essex and Kent	-3.497505	3.112061		0.505777	-0.813285	1.439395
25	Oxfordshire, Surrey and Sussex	-0.989364	-1.516677		0.505777	-1.545261	0.050774
26	Somerset and Wessex	-1.010022	-2.647562		0.505777	-2.357538	-0.288491
27	West Devon and Cornwall	0.254545	-3.948547		0.505777	-2.003661	-0.678787

Small Generation Discount (£/kW)	-11.459901
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Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.181419	0.103783	0.074778
<1320 MW	Redundancy	0.399652	0.247267	0.179833
>=1320 MW	No redundancy		0.325407	0.235335
>=1320 MW	Redundancy		0.534235	0.389947

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.877930	Dinorwig	2.172270	Luichart	0.517906
Aigas	0.590978	Dumnaglass	1.677615	Marchwood	0.345679
An Suidhe	0.854761	Dunlaw Extension	5.366108	Mark Hill	0.791161
Arecleoch	1.877231	Edinbane	6.185278	Millennium	1.650930
Baglan Bay	0.629468	Ewe Hill	1.241717	Moffat	0.172577
Beinneun Wind Farm	1.357822	Fallago	0.895473	Mossford	2.601422
Bhlaraidh Wind Farm	-0.583410	Farr Windfarm	2.036036	Nant	-1.109785
Black Law	1.578926	Ffestiniog	0.228990	Necton	-0.336322
BlackLaw Extension	3.348316	Finlarig	0.289332	Rhigos	0.065754
Bodelwyddan	0.100411	Foyers	0.680399	Rocksavage	0.015953
Brochloch	1.937078	Galawhistle	0.764740	Saltend	0.307669
Carraig Gheal	3.974548	Glendoe	1.662096	South Humber Bank	0.860302
Carrington	-0.039345	Gordonbush	1.172931	Spalding	0.247667
Clyde (North)	0.099095	Griffin Wind	-0.852308	Strathy Wind	2.441031
Clyde (South)	0.114598	Hadyard Hill	2.501066	Western Dod	0.639511
Corriegarh	3.405676	Harestanes	2.284700	Whitelee	0.095898
Corriemoillie	1.503051	Hartlepool	0.540875	Whitelee Extension	0.266597
Coryton	0.312141	Hedon	0.163612		
Cruachan	1.652623	Invergarry	1.282002		
Crystal Rig	0.332039	Kilbraur	1.044886		
Culligran	1.566105	Kilgallioch	0.950992		
Deanie	2.572887	Kilmorack	0.178454		
Dersalloch	2.176599	Langage	0.594127		
Didcot	0.465661	Lochay	0.330665		

Table 4 - Offshore Local Tariffs

Table 4 shows tariffs for generators connected to existing offshore transmission networks. We will discuss tariffs for new offshore networks with the affected generators prior to asset transfer.

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.310632	38.249221	0.949781
Greater Gabbard	13.706576	31.496362	0.000000
Gunfleet	15.821789	14.525641	2.714926
Gwynt Y Mor	16.692416	16.444092	0.000000
Lincs	13.662360	53.491262	0.000000
London Array	9.300327	31.676396	0.000000
Ormonde	22.600549	42.102705	0.335523
Robin Rigg East	-0.418080	27.694200	8.583708
Robin Rigg West	-0.418080	27.694200	8.583708
Sheringham Shoal	21.836047	25.608568	0.556655
Thanet	16.628943	30.985665	0.745934
Walney 1	19.505345	38.844844	0.000000
Walney 2	19.363488	39.187069	0.000000
West of Duddon Sands	7.526580	37.139008	0.000000

2.2 Demand Tariffs 2016/17

Table 5 shows 2016/17 tariffs, including the effect of the Small Generator Discount, for Half Hour metered demand (HH) and Non-Half-Hour metered demand (NHH).

Table 5 - Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	40.966038	5.767784
2	Southern Scotland	40.244453	6.206960
3	Northern	42.927953	6.765895
4	North West	42.828015	5.688026
5	Yorkshire	42.493827	6.543088
6	N Wales & Mersey	42.678395	6.479380
7	East Midlands	44.724594	6.375320
8	Midlands	45.738925	6.354311
9	Eastern	46.543113	6.352770
10	South Wales	42.306722	6.403050
11	South East	49.204313	6.652677
12	London	51.870233	6.508025
13	Southern	50.078028	6.485453
14	South Western	48.580421	6.877890

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.

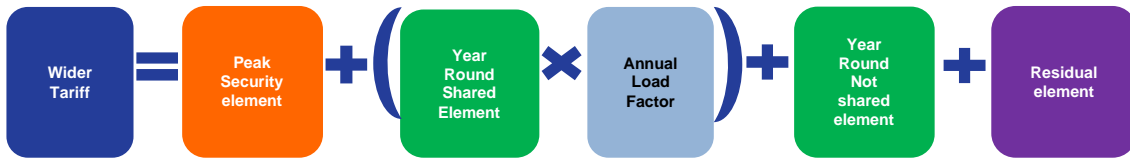
The locational component of TNUoS tariffs does not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct revenue recovery, separate non-locational "residual" tariff elements are included in the generation and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

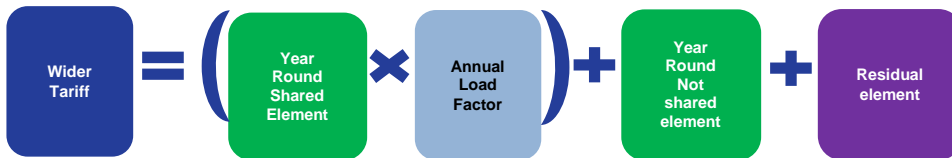
3.2 Project TransmiT

Under the TransmiT methodology there are still 27 generation zones but each zone now has four tariffs rather than just one. A Generator's liability is dependent upon its type of generation. Coal, Nuclear, Gas, Pumped Storage, Oil and Hydro are classed as conventional and wind is intermittent. Liability for each tariff component is shown below:

Conventional Generator



Intermittent Generator



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.

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 the affected NHH demand will still be in transition during 2016/17.

Connection and Use of System Code Modification Proposals 241 and 247 were approved by Ofgem. The combined effect of these is to charge customers that were profile classes 5 to 8 prior to 1 April 2015 the Non-half Hour tariff until 31 March 2017. This means their charges will be based upon profiled 4-7pm demand prior to transfer and metered 4-7pm demand after transfer.

A small number of Metering Class E meters are also treated as Non-Half Hour metered under CMP241/247 but suppliers may opt for these to be treated as Half-Hour metered by providing additional data to National Grid. In summary there will be negligible change to the proportion of chargeable HH demand compared to NHH demand in 2016/17.

4 Updates to the Charging Model for 2016/17

Since the draft tariffs were published in December we have updated allowed revenue using final revenue forecasts from onshore and offshore transmission owners. We have also updated our demand forecasts.

4.1 Changes affecting the locational element of tariffs

The locational element of generation and demand tariffs is based upon demand forecasts provided under the Grid Code, contracted generation at the end of October 2015 and the network model. These are unchanged since the draft tariffs so the location element of tariffs is unchanged. Modelled generation matches contracted generation at the end of October 2015 and Table 6 shows how modelled generation has converged to the generation contracted at the end of October between forecasts. The forecast demand used in the locational model can be found in Appendix B.

Table 6 - Contracted and Modelled TEC

(GW)	2015/16	2016/17 Initial forecast	2016/17 May Forecast	2016/17 July Forecast	2016/17 Oct Forecast	2016/17 Draft Tariffs	2016/17 Final Tariffs
Contracted TEC	78.7	88.5	81.7	79.7	70.4	69.9	69.9
Modelled TEC	78.7	82.9	79.1	71.8	68.2	69.9	69.9

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 7 shows the forecast 2016/17 revenues that have been used in calculating tariffs. Previous forecasts and the final revenue upon which 2015/16 tariffs were set are also included for comparison.

Forecast revenues have been updated with final revenue forecasts from onshore and existing offshore Transmission Owners. National Grid has forecast the revenue requirements of Humber Gateway which is expected to asset transfer during 2016.

Table 7 – Allowed Revenues

£m Nominal	2015/16 TNUoS Revenue	2016/17 TNUoS Revenue					
	Jan 2015 Final	Jan 2015 Initial View	April 2015 Update	July 2015 Update	Oct 2015 Update	Dec 2015 Draft	Jan 2016 Final
National Grid							
<i>Price controlled revenue</i>	1,780.7	1,953.8	1,937.0	1,938.8	1,848.9	1,827.5	1,828.2
<i>Less income from connections</i>	45.0	48.3	45.0	45.0	45.6	45.6	42.7
Income from TNUoS	1,735.7	1,905.5	1,892.0	1,893.9	1,803.3	1,781.9	1,785.5
Scottish Power Transmission							
<i>Price controlled revenue</i>	306.4	321.0	303.1	302.3	300.7	302.6	306.4
<i>Less income from connections</i>	10.7	10.5	8.9	8.9	12.4	12.4	11.8
Income from TNUoS	295.7	310.5	294.2	293.4	288.3	290.2	294.6
SHE Transmission							
<i>Price controlled revenue</i>	341.7	343.0	333.6	329.0	309.0	325.9	326.2
<i>Less income from connections</i>	3.5	3.6	3.5	3.5	3.5	3.5	3.4
Income from TNUoS	338.2	339.5	330.1	325.5	305.5	322.4	322.8
Offshore	248.4	269.1	265.6	259.3	262.5	261.8	260.8
Network Innovation Competition	18.8	48.4	40.5	40.5	40.5	44.9	44.9
Total to Collect from TNUoS	2,636.7	2,873.0	2,822.4	2,812.6	2,700.1	2,701.2	2,708.7

4.2.2 Charging bases for 2016/17

Generation

Whilst the locational element of TNUoS tariffs is fixed using the contracted background on 30 October 2015, the generation charging base reflects the generation that is forecast to pay charges. The generation charging base excludes interconnectors, which are not chargeable, generation likely to close or reduce its capacity before the start of the charging year and new generation likely to delay its connection out of 2016/17. We currently forecast 62.9GW of generation will be chargeable in 2016/17.

Demand

Since the draft tariffs we have updated our demand forecasts with information on the early part of winter 2015/16 and the DECC response to the review of feed-in tariffs. We have also re-examined the locational spread of Non-Half-Hour energy.

We have reduced our forecast of average chargeable demand from 50.0GW to 49.8GW. Whilst peak demands this winter have been broadly in line with expectations there is an increased probability of one or more triads occurring on lower demand days which reduces average chargeable demand.

We have also reduced our forecast of chargeable Half-Hour demand from 13.6GW to 13.1GW. This demand type is incentivised to reduce demand by the Triad charging methodology and therefore the majority of the reduction in total demand is due to this sector. Higher than expected levels of demand response have been observed during early winter 2015/16 both

long-term over periods of several weeks and short-term where warning of triads have been issued for individual days.

We have increased our forecast of NHH demand from 24.6TWh to 26.1TWh. This reflects the government's decision in December to cap the feed-in tariff benefit and feedback from suppliers on our solar assumptions. These reduce the output from solar and therefore lessen the previously forecast reduction in Non-Half-Hour demand.

We have also used local climate data to improve the locational modelling of the non-half-hour demand. The resulting re-distribution of demand is more in line with that observed in recent years and removes some of the high NHH tariff increases forecast in the draft tariffs. However, there is more reduction in non-half-hour demand in the south west to reflect growth of solar capacity and its favourable climate.

Appendix B shows the changes in demand charging base. Table 8 shows the charging bases used in these tariffs.

Table 8 - Charging Base

Charging Base	2015/16	2016/17
Generation (GW)	71.5	62.9
Total Average Triad (GW)	52.4	49.8
HH Demand Average Triad (GW)	15.0	13.1
NHH Demand (4pm-7pm TWh)	27.4	26.1

4.2.3 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. We have included those Interconnectors that were contracted to be connected in 2016/17 as at the end of October 2015. Interconnectors are not liable for generation or demand TNUoS charges so are not included in the generation or demand charging bases, see Table 9.

Table 9 - 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	295	0

4.2.4 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. As in previous forecasts an 8.2% error margin has been applied to reflect revenue and output forecasting accuracy.

As prescribed by the Use of System charging methodology, the exchange rate for 2016/17 is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2015. The value of €1.36/£ is unchanged from previous forecasts.

The forecast output of generation subject to Generation TNUoS charges is unchanged at 268.7TWh. The parameters used to calculate the proportions of revenue collected from generation and demand are shown in Table 10.

Table 10 - Generation and Demand revenue proportions

		2015/16	2016/17
CAP _{EC}	Limit on generation tariff (€/MWh)	2.5	2.5
y	Error Margin	6.4%	8.2%
ER	Exchange Rate (€/£)	1.22	1.36
MAR	Total Revenue (£m)	2,636.7	2,708.7
GO	Generation Output (TWh)	319.6	268.7
G	% of revenue from generation	23.2%	16.7%
D	% of revenue from demand	76.8%	83.3%
G.R	Revenue recovered from generation (£m)	611.7	453.4
D.R	Revenue recovered from demand (£m)	2,025.0	2,255.2

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.

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

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

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.

Typically 75% of offshore revenues are recovered from offshore local tariffs. In 2016/17 offshore local tariffs are forecast to be £200.6m which is included in the revenue recovered from generation.

Table 11 - Residual Calculation

		2015/16	2016/17
R_G	Generator residual tariff (£/kW)	4.81	0.51
R_D	Demand residual tariff (£/kW)	35.63	45.33
G	Proportion of revenue recovered from generation (%)	23.2%	16.7%
D	Proportion of revenue recovered from demand (%)	76.8%	83.3%
R	Total TNUoS revenue (£m)	2,637	2,709
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	47.6	191.9
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	157.7	-2.4
O	Revenue recovered from offshore local tariffs (£m)	186.6	200.6
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.1	15.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.8	13.3
B_G	Generator charging base (GW)	71.5	62.9
B_D	Demand charging base (GW)	52.4	49.8

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant used to calculate the cost of moving 1MW over 1km using 400kV Overhead line is unchanged from the draft tariffs at £13.336061/MWkm.

4.3.2 Small Generator Discount

On 22 January 2016, Ofgem amended the expiry date of special condition C13 in National Grid's licence to extend the small generator discount to 31 March 2019. This confirms the discount which was included in the draft tariffs.

The value of the small generator discount and the additional charge to suppliers is set out in Table 12.

Table 12 – Small Generator Discount

Small Generator Discount Calculation		
Generator Residual (£/kW)	G	0.505777
Demand Residual (£/kW)	D	45.333826
Small Generator Discount (£/kW)	$T = (G + D)/4$	11.459901
Forecast Small Generator Volume (kW)	V	2,287,000
2016/17 SGD cost (£)	$V \times T$	26,208,794
Prior year reconciliation (£)	R	207,773.10
Total SGD Cost (£)	$C = (V \times T) + R$	26,416,567
Total System Triad Demand (kW)	TD	49,800,000
Total HH Triad Demand (kW)	HHD	13,100,500
Total NHH Consumption (kWh)	NHHD	26,146,825,000
Increase in HH Demand tariff (£/kW)	$HHT = C/TD$	0.530453
Total Cost to HH Customers (£)	$HHC = HHT * HHD$	6,949,201
Increase in NHH Demand tariff (p/kWh)	$NHHT = (C - HHC)/NHHD$	0.074454
Total Cost to NHH Customers (£)	$NHHC = NHHT * NHHD$	19,467,365

5 Forecast generation tariffs for 2016/17

The following section provides details of the wider and local generation tariffs for 2016/17.

5.1 Wider zonal generation tariffs

Table 13 and Figure 1 show the changes in generation wider TNUoS tariffs between 2015/16 and 2016/17. The key change between the two years is the change in methodology due to CUSC Modification Proposal 213, otherwise known as Transmit. In 2015/16 there were 27 generation zones each with a wider tariff paid by all generators in that zone. In 2016/17 the 27 generation zones have four tariff elements which are combined into a wider tariff specific to each generator depending on whether it is conventional or intermittent and its annual load factor. As an example, Table 13 and Figure 1 show how the tariffs change for a conventional generator with a 70% load factor and an intermittent generator with a 30% load factor.

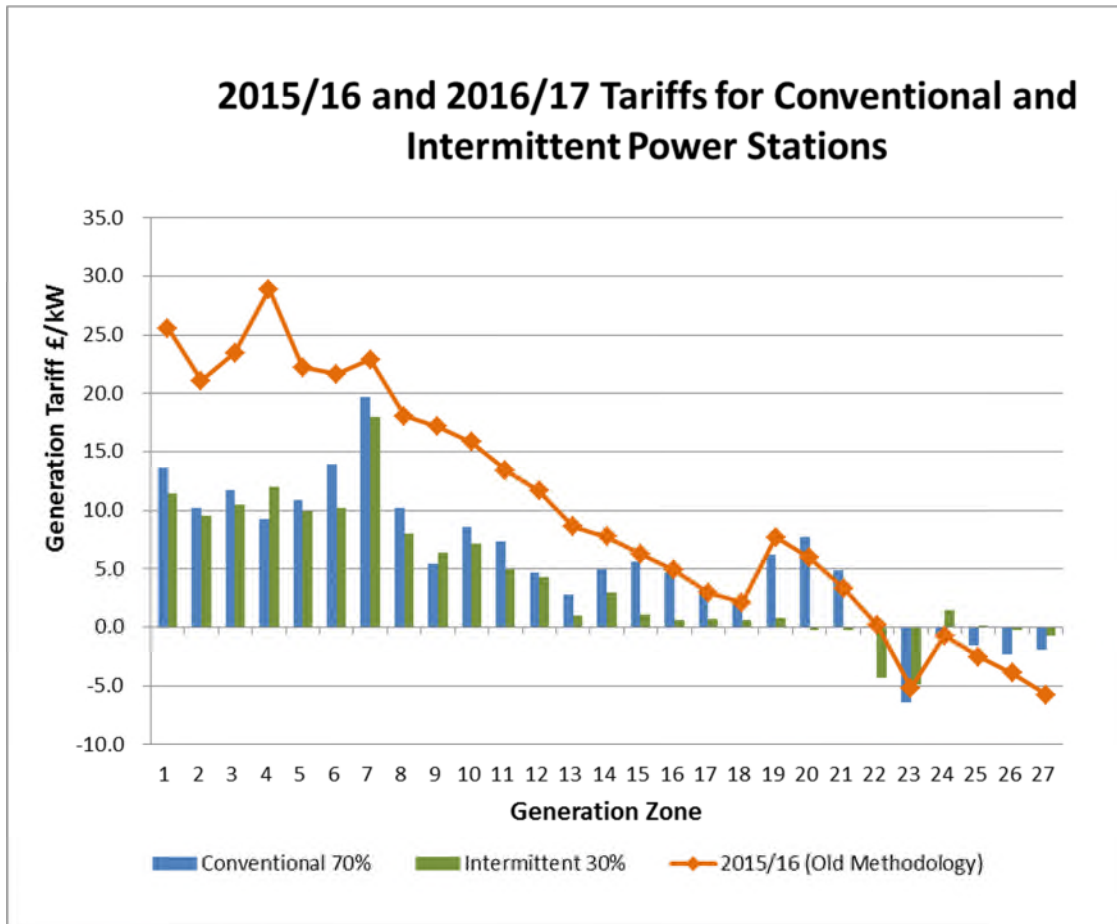
Generally generator tariffs have reduced because lower forecast generation output combined with a weaker Euro have reduced the revenue that can be recovered from generation within the €2.5/MWh cap on average annual generator charges. The new charging methodology, coupled with the closure of Longannet Power Station flattens the tariff profile with greater reductions in Scotland and the North of England and less negative tariffs in some of the more southerly zones. The flattening of tariffs is more noticeable for intermittent generation which is not exposed to the peak element of the new tariff structure.

The peak in tariffs around Zone 7 is due to the new Hunterston–Crossaig subsea cable whose cost is reflected in generator tariffs close to the northern end of this reinforcement.

Table 13 – Generation tariff changes

Wider Generation Tariffs (£/kW)						
Zone	Zone Name	2015/16 Final Tariffs (£/kW)	Conventional 70%		Intermittent 30%	
			Conventional 70% 2016/17 Final Tariffs (£/kW)	Change (£/kW)	Intermittent 30% 2016/17 Final Tariffs (£/kW)	Change (£/kW)
1	North Scotland	25.55	13.64	-11.90	11.43	-14.12
2	East Aberdeenshire	21.08	10.24	-10.85	9.52	-11.56
3	Western Highlands	23.46	11.74	-11.71	10.49	-12.97
4	Skye and Lochalsh	28.87	9.20	-19.66	11.96	-16.91
5	Eastern Grampian and Tayside	22.21	10.83	-11.39	9.95	-12.26
6	Central Grampian	21.64	13.90	-7.75	10.18	-11.47
7	Argyll	22.89	19.66	-3.23	18.00	-4.89
8	The Trossachs	18.03	10.20	-7.83	7.96	-10.07
9	Stirlingshire and Fife	17.15	5.40	-11.75	6.42	-10.73
10	South West Scotland	15.83	8.57	-7.25	7.18	-8.64
11	Lothian and Borders	13.37	7.38	-5.99	5.01	-8.37
12	Solway and Cheviot	11.62	4.66	-6.96	4.30	-7.32
13	North East England	8.60	2.77	-5.83	1.02	-7.58
14	North Lancs and The Lakes	7.73	4.93	-2.80	2.98	-4.75
15	South Lancs, Yorks and Humber	6.26	5.62	-0.64	1.03	-5.22
16	North Midlands and North Wales	4.89	4.71	-0.18	0.65	-4.24
17	South Lincs and North Norfolk	2.97	3.17	0.19	0.69	-2.29
18	Mid Wales and The Midlands	2.09	2.35	0.26	0.60	-1.48
19	Anglesey and Snowdon	7.68	6.19	-1.50	0.81	-6.87
20	Pembrokeshire	5.93	7.75	1.81	-0.30	-6.23
21	South Wales	3.31	4.90	1.59	-0.29	-3.60
22	Cotswold	0.21	0.13	-0.08	-4.31	-4.51
23	Central London	-5.21	-6.40	-1.19	-4.88	0.33
24	Essex and Kent	-0.75	-0.81	-0.07	1.44	2.19
25	Oxfordshire, Surrey and Sussex	-2.55	-1.55	1.01	0.05	2.60
26	Somerset and Wessex	-3.94	-2.36	1.59	-0.29	3.66
27	West Devon and Cornwall	-5.80	-2.00	3.80	-0.68	5.13

Figure 1 - Variation in Generation Zonal Tariffs



5.2 Onshore local circuit tariffs

Where a non-distributed generator is not directly connected to the Main Interconnected Transmission System (MITS) the Onshore Local Circuit Tariffs reflect the cost and flows on circuits between its connection and the MITS. These are unchanged from the draft tariffs. 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 2016/17 to reflect the fact that the customer has already paid/or will pay for the non-standard incremental cost.

* CUSC section 14.15.12 to 14.15.20

Table 14 - Circuits subject to one off charges

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

5.3 Onshore local substation tariffs

Local substation tariffs reflect the cost of the first transmission substation to which non-distribution generators connect. These are unchanged from the draft tariffs.

5.4 Offshore local generation tariffs

The local offshore tariffs (substation, circuit and ETUoS) reflect the cost of offshore networks connecting offshore generation. These are unchanged from the draft tariffs. Offshore local generation tariffs associated with Offshore Transmission Owners yet to be appointed will be calculated following their appointment.

6 Forecast demand tariffs for 2016/17

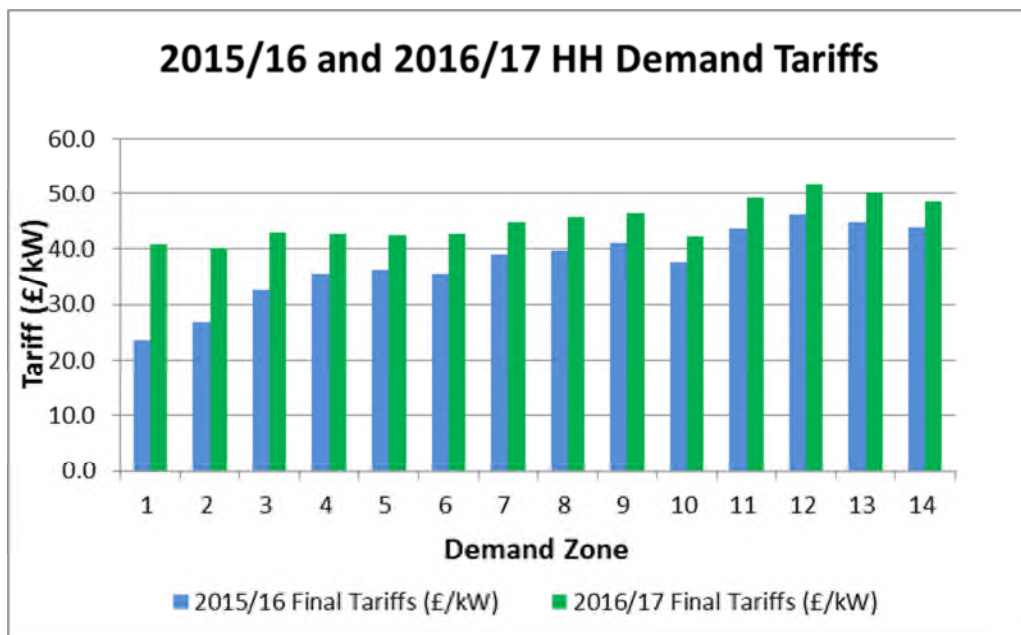
6.1 Half Hour demand tariffs

Table 15 and Figure 2 show the difference between Half-Hourly (HH) demand tariffs forecast in 2015/16 and 2016/17.

Table 15 - Change in HH Demand Tariffs

Zone	Zone Name	2015/16 Final Tariffs (£/kW)	2016/17 Final Tariffs (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	23.47	40.97	17.50	9.70
2	Southern Scotland	26.79	40.24	13.46	9.70
3	Northern	32.62	42.93	10.31	9.70
4	North West	35.68	42.83	7.14	9.70
5	Yorkshire	36.29	42.49	6.21	9.70
6	N Wales & Mersey	35.62	42.68	7.06	9.70
7	East Midlands	39.07	44.72	5.66	9.70
8	Midlands	39.63	45.74	6.11	9.70
9	Eastern	41.18	46.54	5.37	9.70
10	South Wales	37.61	42.31	4.70	9.70
11	South East	43.74	49.20	5.47	9.70
12	London	46.24	51.87	5.63	9.70
13	Southern	44.79	50.08	5.29	9.70
14	South Western	43.98	48.58	4.60	9.70

Figure 2 - HH Demand Tariffs



The average HH demand tariff has increased by £6.34/kW due to the increase in revenue to be collected, a reduction in the amount of this revenue that can be collected from generation due to the €2.5/MWh cap on average annual generation tariffs and a reduction in system demand. Larger increases in tariffs occur in Scotland and Northern England following the closure of Longannet Power Station.

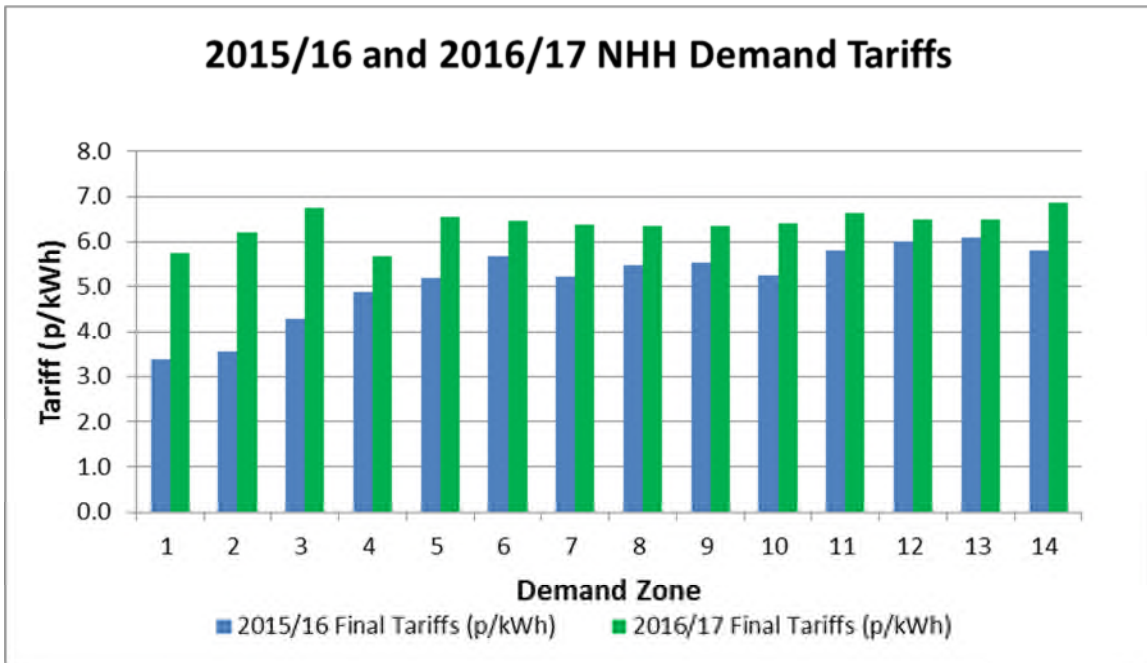
6.2 Non Half-hourly demand tariffs

Table 16 and Figure 3 show the difference between Non-Half-Hourly (NHH) demand tariffs in 2015/16 and 2016/17.

Table 16 - NHH Demand Tariff Changes

Zone	Zone Name	2015/16 Final Tariffs (p/kWh)	2016/17 Final Tariffs (p/kWh)	Change (p/kWh)
1	Northern Scotland	3.39	5.77	2.38
2	Southern Scotland	3.56	6.21	2.65
3	Northern	4.28	6.77	2.48
4	North West	4.87	5.69	0.81
5	Yorkshire	5.19	6.54	1.36
6	N Wales & Mersey	5.68	6.48	0.80
7	East Midlands	5.23	6.38	1.14
8	Midlands	5.49	6.35	0.87
9	Eastern	5.54	6.35	0.81
10	South Wales	5.25	6.40	1.16
11	South East	5.81	6.65	0.84
12	London	6.01	6.51	0.50
13	Southern	6.09	6.49	0.40
14	South Western	5.81	6.88	1.07

Figure 3 - NHH Demand Tariff Changes



The average Non Half Hour tariff increases by 1.03p/kWh for the same reasons the average HH tariff has increased and due to lower forecast NHH demand. As for the HH tariffs, larger increases occur in Scotland and Northern England following the closure of Longannet Power Station. The increase in zone 14 (south West) reflects the growth of solar which is reducing chargeable NHH demand in this zone.

7 Tools and Supporting Information

7.1 Further information

We are keen to ensure that customers understand the current charging arrangements and the reason why tariffs change. If you have specific queries on this forecast please contact us using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

7.2 Charging 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. Please also note that it will be based upon contracted generation rather than National Grid's assumptions to protect commercial sensitivities.

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

7.3 Numerical data

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

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

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Appendices

Appendix A: Revenue Tables

Appendix B: Demand changes

Appendix C: Generation Zones

Appendix D: Demand Zones

Appendix A : Revenue Tables

These pages provide more detail on the revenue 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, not yet available 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 allowances 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.

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

Table 17 – National Grid Revenue Forecast

National Grid Revenue Forecast			25/01/2016			Notes
Description		Licence	Yr t-1	Yr t	Yr t+1	
Regulatory Year			2014/15	2015/16	2016/17	
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%	0.95%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	1,443.8	1,475.6	1,571.4	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	-5.5	-114.4	-185.4	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	-0.5	4.7	-19.9	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3.1%	2.5%	1.0%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3.1%	2.4%	2.1%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3.0%	3.2%	3.0%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	1.2051	1.2267	1.2330	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	A	BRT	1732.7	1675.5	1684.4	
Pass-Through Business Rates	B1	RBt		1.2	1.5	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	0.1	0.0	0.1	Licensee Actual/Forecast
Licence Fee	B3	LFt		2.0	2.7	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt		3.8	2.7	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	312.2	295.7	294.6	14/15 & 15/16 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	214.0	338.2	322.8	14/15 & 15/16 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	218.4	248.4	260.8	14/15 & 15/16 Charge setting. Later from OFTO Calculation.
Embedded Offshore Pass-Through	B9	OFETt	0.4	0.6	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	
Reliability Incentive Adjustment	C1	RIt		2.4	3.9	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt		8.7	10.1	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt		2.8	2.7	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0	2.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	C	OIPt	0.0	13.9	18.7	
Network Innovation Allowance	D	NIAt	10.9	10.6	10.6	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	17.8	18.8	44.9	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt			0.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	16.0	15.7	0.0	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	2.0	0.8	2.9	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	-0.3	0.1	0.1	Licensee Actual/Forecast
Correction Factor	K	-Kt		56.4	104.0	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+K]	M	TOT	2524.3	2681.6	2751.3	
Termination Charges	B5		0.0	0.0	0.0	
Pre-vesting connection charges	P		47.0	45.0	42.7	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	T		2477.3	2636.7	2708.7	
Final Collected Revenue	U	TNRt	2375.9			Licensee Actual/Forecast
Forecast percentage change to Maximum Revenue M			0.0%	6.2%	2.6%	
Forecast percentage change to TNUoS Collected Revenue T			0.0%	6.4%	2.7%	

Table 18 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast			Updated:	25/01/2016		
Description	Licence Term	Yr t-1	Yr t	Yr t+1	Notes	
		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%	National Grid forecast	
Opening Base Revenue Allowance (2009/10 prices)	A1 PUt	237.0	258.6			
Price Control Financial Model Iteration Adjustment	A2 MODt	6.2	-20.3			
RPI True Up	A3 TRUt	-0.1	0.9			
RPI Forecast	A4 RPIFt	1.2051	1.2267		National Grid forecast	
Base Revenue [A=(A1+A2+A3)*A4]	A BRt	292.9	293.4			
Pass-Through Business Rates	B1 RBt	0.0	-20.2			
Temporary Physical Disconnection	B2 TPDt	0.0	0.0			
Pass-Through Items [B=B1+B2]	B PTt	0.0	-20.2			
Reliability Incentive Adjustment	C1 RIt	0.0	2.6			
Stakeholder Satisfaction Adjustment	C2 SSOt	0.0	1.7			
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3 SFlt	0.0	-0.2			
Awarded Environmental Discretionary Rewards	C4 EDRt	0.0	0.0			
Financial Incentive for Timely Connections Output	C5 -CONADJt	0.0	0.0			
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	C OIPt	0.0	4.1			
Network Innovation Allowance	D NIAt	0.7	1.3			
Transmission Investment for Renewable Generation	G TIRGt	29.3	29.6			
Correction Factor	K -Kt	0.0	8.7			
Maximum Revenue (M= A+B+C+D+G+J+K)	M TOT	322.9	316.8	306.4		
Excluded Services	P EXCt	7.7	8.0	9.4	Post BETTA Connection Charges	
Site Specific Charges	S EXSt	18.5	18.8	21.2	Pre & Post BETTA Connection Charges	
TNUoS Collected Revenue (T=M+P-S)	T TSPT	312.1	306.0	294.6	General System Charge	
Final Collected Revenue	U TNRT	312.2				
Forecast percentage change to TNUoS Collected Revenue T		0.0%	-1.9%	-3.7%		

Table 19 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast			Updated:		25/01/2016	
Description	Licence Term		Yr t-1	Yr t	Yr t+1	Notes
			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%	National Grid forecast
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	111.5	124.1		From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	8.7	85.2		
RPI True Up	A3	TRUt	-0.0	0.5		
RPI Forecast	A4	RPIFt	1.2051	1.2267		National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	A	BRt	144.9	257.4		
Pass-Through Business Rates	B1	RBt	0.0	-0.7		
Temporary Physical Disconnection	B2	TPDt	0.0	0.6		
Pass-Through Items [B=B1+B2]	B	PTt	0.0	-0.1		
Reliability Incentive Adjustment	C1	RIt		1.2		
Stakeholder Satisfaction Adjustment	C2	SSOt		1.6		
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIIt		-0.1		
Awarded Environmental Discretionary Rewards	C4	EDRt		0.0		
Financial Incentive for Timely Connections Output	C5	-CONADJt		0.0		
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	C	OIPt	0.0	2.7		
Network Innovation Allowance	D	NIAt	1.3	1.3		
Transmission Investment for Renewable Generation	G	TIRGt	72.2	81.2		
Compensatory Payments Adjustment	J	SHCPt	0.0	0.4		
Correction Factor	K	-Kt		-1.7		
Maximum Revenue (M= A+B+C+D+G+J+K)	M	TOT	218.3	341.1	326.2	
Excluded Services	P	EXCt	0.0	0.0	0.0	Post BETTA Connection Charges
Site Specific Charges	S	EXSt	3.5	3.5	3.4	Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	T	TSHt	214.8	337.6	322.8	General System Charge
Final Collected Revenue	U	TNRt				
Forecast percentage change to TNUoS Collected Revenue T			0.0%	57.2%	-9.5%	

Table 20 - Offshore Transmission Owner Revenues

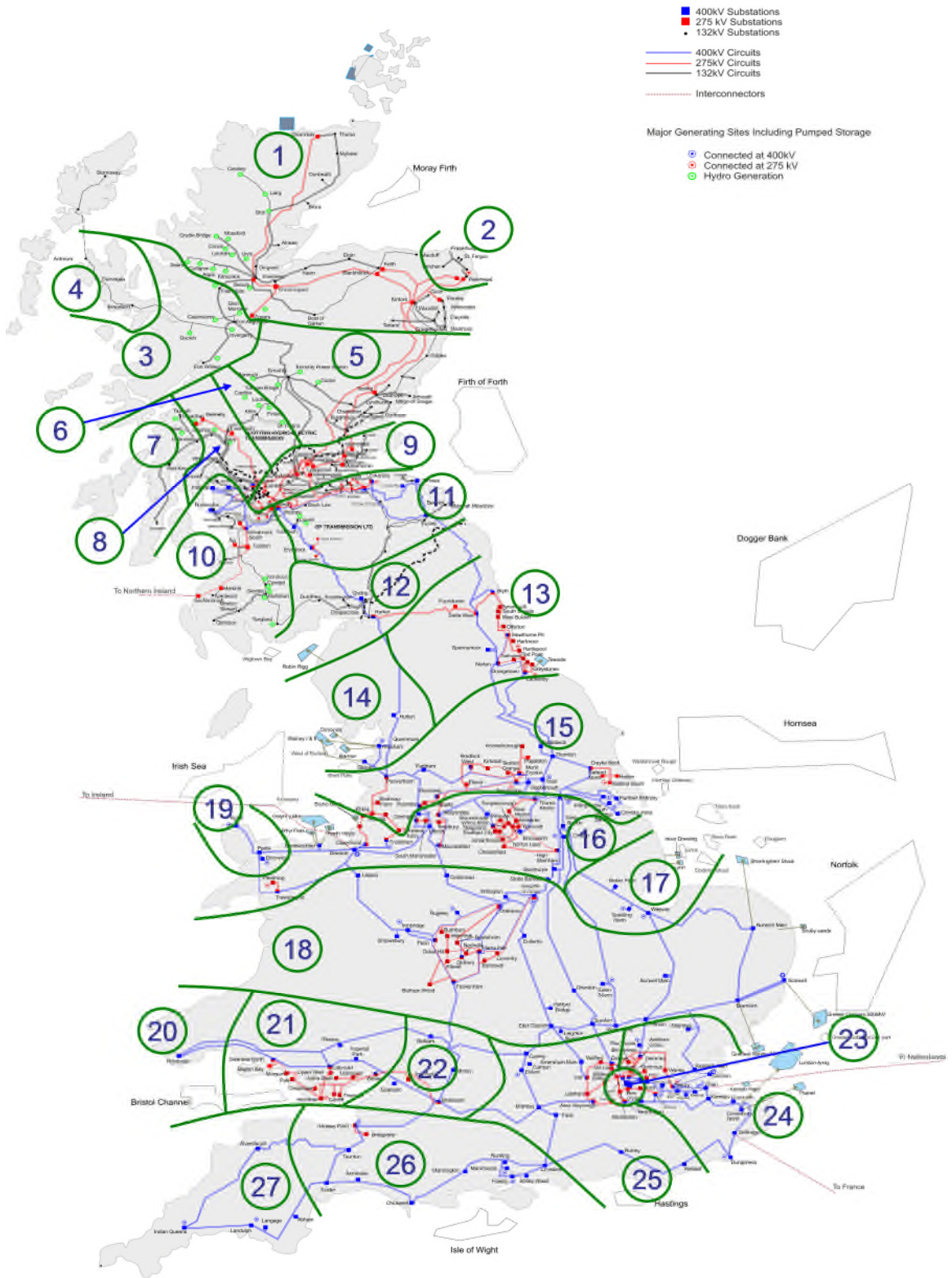
Offshore Transmission Revenue Forecast	25/01/2016			Notes
	Description	Yr t-1	Yr t	
Regulatory Year	2014/15	2015/16	2016/17	
Barrow	5.5	5.6	5.7	
Gunfleet	6.9	7.0	7.1	
Walney 1	12.5	12.8	12.9	
Robin Rigg	7.7	7.9	8.0	
Walney 2	12.9	13.2	12.5	
Sheringham Shoal	18.9	19.5	19.7	
Ormonde	11.6	11.8	12.0	
Greater Gabbard	26.0	26.6	26.9	
London Array	37.6	39.2	39.5	
Thanet	78.9	17.5	15.7	
Lincs		25.6	26.7	
Gwynt y mor		26.3	23.6	
West of Duddon Sands			21.3	
Humber Gateway		35.3	29.3	National Grid Forecast
Westermost Rough				
Offshore Transmission Pass-Through (B7)	218.4	248.4	260.8	

Appendix B : Demand changes

Table 21 - Demand Profiles

Zone	Zone Name	2015/16 Final Tariffs				2016/17 Final Tariffs			
		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	865	1,125	-79	0.83	623	574	-461	0.73
2	Southern Scotland	3,866	3,683	1,188	1.88	3,226	3,187	474	1.76
3	Northern	2,921	2,355	518	1.40	2,609	2,216	137	1.32
4	North West	4,091	4,222	1,246	2.18	4,005	3,682	909	2.09
5	Yorkshire	4,864	4,061	1,203	2.00	4,559	3,897	972	1.90
6	N Wales & Mersey	2,688	2,855	615	1.40	2,092	2,981	990	1.31
7	East Midlands	5,269	4,840	1,619	2.40	4,967	4,797	1,537	2.29
8	Midlands	4,512	4,424	1,278	2.27	4,414	4,225	1,226	2.16
9	Eastern	6,205	6,265	1,581	3.48	5,581	6,046	1,455	3.36
10	South Wales	1,993	1,871	571	0.93	1,920	2,252	925	0.88
11	South East	3,851	3,750	881	2.16	3,609	3,631	819	2.08
12	London	5,489	4,872	2,161	2.09	4,730	4,436	1,763	2.13
13	Southern	6,195	5,610	1,658	2.91	5,814	5,595	1,977	2.80
14	South Western	2,922	2,467	547	1.45	2,699	2,282	378	1.35
Total		55,732	52,400	14,987	27.39	50,848	49,800	13,101	26.15

Appendix C : Generation Zones



Appendix D : Demand Zones

