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Tariff Information Paper

May 2015 forecast of TNUoS tariffs for 2016/17

This information paper provides National Grid's forecast of Transmission Network Use of System (TNUoS) tariffs for 2016/17, which apply to Generators and Suppliers. It is the second of a series of updates that National Grid will publish throughout the year.

13 May 2015

V1.1

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1 Executive Summary

Transmission Network Use of System (TNUoS) tariffs are paid by Generators and Suppliers for use of the GB transmission system. This report shows how our forecast of 2016/17 TNUoS tariffs has changed since January.

2014 was a mild year and this, together with growth in embedded generation, reduced the volume of chargeable demand during 2014/15. This led to the recovered revenue on behalf of all transmission owners being less than allowed. Therefore our forecast for 2016/17 allowed revenue includes £105m to recover this shortfall, although overall our revenue forecast has reduced due to lower inflation. We have also reduced the demand charging bases (MW and TWh) to reflect continued growth in embedded generation.

2016/17 sees the implementation of a number of industry changes. This forecast is based on the CMP213, or Transmit, methodology which National Grid has been directed to implement from 1 April 2016. This is currently subject to Judicial Review but we will continue to use this methodology unless advised otherwise by Ofgem.

2016/17 also sees the expiration of the small generator discount under National Grid's licence and the migration of profile classes 5 to 8 from Non-Half-Hour metered to Half-Hour metered charging is also expected to be complete. Both of these have been reflected in this forecast. CMP239 looks to continue the small Generator discount in some form and so this may be included in future forecasts.

The proportion of revenue collected from Generators is forecast to reduce to £548m due to the €2.5/MWh cap in average annual generator charges and a weaker Euro. This increases the proportion of revenue collected from Suppliers, which together with the smaller charging base is expected to increase demand tariffs.

This forecast has had a number of data input changes: updated TEC; latest week 24 demand data; revised generation and demand charging bases; and updated revenue estimates.

We will update our forecast of 2016/17 tariffs on a quarterly basis taking new information into account as it becomes available. This includes changes in generation, forecast demand, allowed revenue and circuit data. TNUoS tariffs for 2016/17 will be finalised at the end of January 2016.

2 Tariff Summary

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

2.1 Generation Tariffs 2016/17

Table 1 - Wider Generation Tariffs

		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	3.05	14.11	7.78	1.50	22.22	13.52
2	East Aberdeenshire	4.11	7.67	7.78	1.50	18.76	11.59
3	Western Highlands	2.88	12.03	7.48	1.50	20.29	12.59
4	Skye and Lochalsh	-2.88	12.03	7.24	1.50	14.29	12.35
5	Eastern Grampian and Tayside	2.29	11.09	7.05	1.50	18.61	11.88
6	Central Grampian	4.28	10.90	6.92	1.50	20.33	11.69
7	Argyll	3.17	8.74	10.24	1.50	21.03	14.36
8	The Trossachs	3.47	8.74	5.32	1.50	16.41	9.45
9	Stirlingshire and Fife	3.77	7.69	4.94	1.50	15.60	8.75
10	South West Scotlands	2.45	8.87	4.94	1.50	15.10	9.10
11	Lothian and Borders	2.89	8.87	1.11	1.50	11.71	5.27
12	Solway and Cheviot	1.44	5.55	3.30	1.50	10.12	6.46
13	North East England	3.34	3.01	1.65	1.50	8.59	4.05
14	North Lancashire and The Lakes	1.71	3.01	1.92	1.50	7.24	4.32
15	South Lancashire, Yorkshire and Humber	3.73	1.28		1.50	6.13	1.88
16	North Midlands and North Wales	3.29	0.16		1.50	4.90	1.55
17	South Lincolnshire and North Norfolk	1.59	-0.21		1.50	2.94	1.44
18	Mid Wales and The Midlands	1.09	-0.15		1.50	2.48	1.46
19	Anglesey and Snowdon	4.39	2.08		1.50	7.35	2.12
20	Pembrokeshire	7.95	-4.26		1.50	6.47	0.22
21	South Wales & Gloucester	5.08	-4.36		1.50	3.53	0.19
22	Cotswold	1.96	2.51	-6.95	1.50	-1.73	-4.70
23	Central London	-3.29	2.51	-5.22	1.50	-5.24	-2.96
24	Essex and Kent	-4.26	2.51		1.50	-1.00	2.25
25	Oxfordshire, Surrey and Sussex	-1.57	-2.38		1.50	-1.73	0.79
26	Somerset and Wessex	-2.18	-4.32		1.50	-3.70	0.20
27	West Devon and Cornwall	-1.89	-6.68		1.50	-5.06	-0.50

Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.19	0.11	0.08
<1320 MW	Redundancy	0.41	0.25	0.18
>=1320 MW	No redundancy		0.33	0.24
>=1320 MW	Redundancy		0.55	0.40

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.97	Dinorwig	2.23	Kilmorack	0.18
Aigas	0.61	Dunlaw Extension	1.33	Langage	0.61
An Suidhe	2.82	Brochloch	1.10	Lochay	0.34
Arecleoch	3.29	Dumnaglass	3.35	Luichart	1.05
Baglan Bay	0.67	Edinbane	6.34	Mark Hill	0.81
Beinneun Wind Farm	4.54	Ewe Hill	4.86	Margee	0.88
Afton	2.15	Farr Windfarm	0.00	Marchwood	0.07
Black Craig	1.13	Fallago	0.61	Millennium Wind	0.00
Blacklaw Extension	2.03	Carraig Gheal	4.07	Mossford	0.71
Black Law	0.93	Ffestiniogg	0.23	Nant	-1.14
Bodelwyddan	0.10	Finlarig	0.30	Dudgeon Offshore Wind Farm	-0.35
Carrington	0.00	Foyers	0.71	Neilston	-2.21
Clyde (North)	0.10	Glendoe	1.70	Newfield	3.61
Clyde (South)	0.12	Glenmoriston	1.22	Rhigos	0.12
Coalburn	0.06	Ulzieside	2.15	Rocksavage	0.02
Corriegarth	2.35	Gordonbush	1.20	Saltend	0.31
Corriemoillie	2.54	Griffin Wind	5.79	South Humber Bank	0.38
Coryton	0.05	Hadyard Hill	2.56	Spalding	0.25
Cruachan	1.65	Harestanes	4.91	Kilbraur	1.07
Crystal Rig	0.21	Hartlepool	0.55	Strathy Wind	2.20
Culligran	1.60	Hedon	0.18	Aikengall II	1.35
Deanie	2.64	Hornsea	0.14	Whitelee	0.10
Dersalloch	3.95	Invergarry	1.31	Whitelee Extension	0.27
Didcot	0.47	Kilgallioch	0.97		

Table 4 - Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Barrow	7.33	38.35	0.95
Greater Gabbard	13.74	31.58	0.00
Gunfleet	15.86	14.56	2.72
Gwynt Y Môr	16.74	16.49	0.00
Lincs	13.70	54.92	0.00
London Array	9.32	31.76	0.00
Ormonde	22.66	42.21	0.34
Robin Rigg East	-0.42	27.77	8.61
Robin Rigg West	-0.42	27.77	8.61
Sheringham Shoal	21.89	25.68	0.56
Walney 1	19.56	38.95	0.00
Walney 2	19.41	39.29	0.00

2.2 Demand Tariffs 2016/17

Table 5 - Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	29.34	4.34
2	Southern Scotland	31.40	4.57
3	Northern	37.38	5.05
4	North West	40.92	5.77
5	Yorkshire	41.67	6.10
6	N Wales & Mersey	41.28	6.79
7	East Midlands	44.85	6.23
8	Midlands	45.62	6.53
9	Eastern	46.97	6.45
10	South Wales	44.09	6.37
11	South East	49.65	6.72
12	London	51.95	7.12
13	Southern	51.00	7.16
14	South Western	51.30	6.92

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 in different parts of the country 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. However, for offshore Generators, project specific costs are taken into account since these costs vary significantly from one project to another.

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 total revenue recovery, separate non-locational “residual” tariff elements are included in the generation and demand tariffs. The residuals are set to ensure that enough revenue is recovered to pay the Transmission Owners their allowed revenues.

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 where local connections are single circuit. These charges are therefore locational and specific to individual Generators.

3.2 Generation:Demand split

EU Regulation ECR 838/2010 limits average annual generation use of system charges to €2.5/MWh. We forecast this will restrict the use of system revenue that can be collected from Generators to £548m or 19.4% of TNUoS revenue, with the remainder collected from Suppliers.

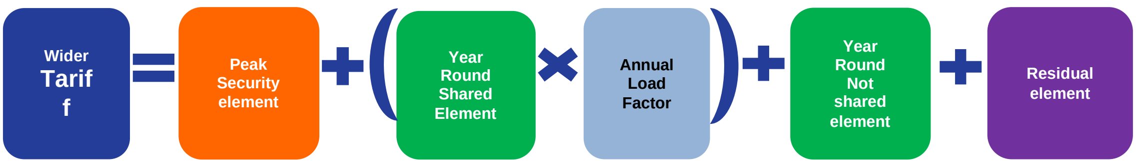
3.3 Project TransmiT

On conclusion of Ofgem's Significant Code Review of gas and electricity transmission charging arrangements known as Project TransmiT, National Grid were directed to raise a CUSC modification proposal (CMP213) to consider potential improvements to the TNUoS charging methodology. On 11 July 2014 Ofgem approved Workgroup Alternative Code Modification 2 (WACM2) with an implementation date of 1 April 2016.

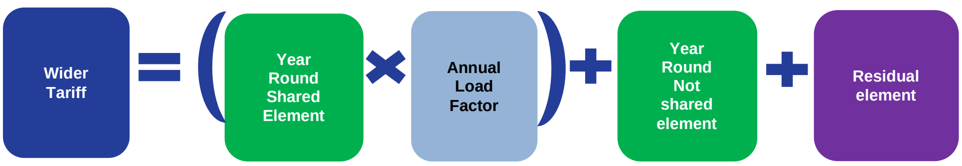
RWE raised a Judicial Review of the decision to implement CMP213 and hearings are expected to take place 1-2 July 2015. This forecast is based on the approved CMP213 methodology which National Grid has been directed to implement.

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, Peaking and Hydro are classed as conventional and wind is intermittent. Liability for each tariff component is shown below:

Conventional Generator



Intermittent Generator



Annual Load Factors are calculated each year and will be available before 25 December. Examples based on 2008/9 to 2012/13 data can be found on our website[1].

3.4 P272 and CMP241

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. This change is to be implemented by 1 April 2016 and therefore the demand forecasts in this forecast fully reflect this change.

CMP241 was approved by Ofgem on 30 March 2015. CMP241 treats metering classes E, F and G as NHH rather than HH during the year of transition unless a Supplier provides further information as specified in CMP241. We will be writing to CUSC parties explaining the times

[1] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29505

and exact dates required by CMP241. CMP241 has no effect after the migration and therefore is not included in this forecast.

We estimate that profile classes 5 to 8 would have contributed 2.5TWh (9.4%) to 2016/17 NHH demand between the hours of 4 and 7pm. Therefore the NHH demand base is reduced by this amount with the decrease spread across each zone on a pro-rata basis. As half hourly metered demand we estimate these classes will increase 2016/17 Triad demand by 3.7GW (26.7%) and therefore the HH demand base has been increased by this amount using the NHH proportions for each zone. The revenue recovered from this demand as Half-Hour metered demand is similar to what would be recovered as Non-Half-Hour metered demand and therefore the impact on HH and NHH tariffs is expected to be minimal. A similar effect was included in the January forecast. For future forecasts we will endeavour to represent the NHH classes 5 to 8 on an individual zonal basis.

4 Updates to the Charging Model for 2016/17

Since our forecast in January, we have updated: total revenue (using the most up to date information); contracted generation (as per TEC register and best view); chargeable generation (latest forecast); locational demand (week 24 data); chargeable demand (latest forecast) and the proportion of revenue recovered from generation. There have been no changes to the charging methodology or circuit data.

We will continue to update total revenue, contracted generation, chargeable generation, chargeable demand and circuit data later in the year.

4.1 Changes affecting the locational element of tariffs

4.1.1 Contracted Generation

We have updated generation for 2016/17 using the contracted generation background on 13 April 2015. Table 23 in Appendix B shows the change in contracted Transmission Entry Capacity since the January forecast. Zones 1 to 12 represent Scotland and Zones 13 to 27 represent England & Wales.

The locational element of tariffs will be fixed using the contracted background on 31 October 2015. Differences to the present register may include TEC reductions of existing power stations for which notification has not yet been received and delays to future connections expected in 2016/17. These will be published in the TEC Register and taken into account in future updates of forecast tariffs.

Since CMP240 extends the period in which notifications can be given without incurring a cancellation charge[2], there may be changes to the TEC register following the conclusion of the Judicial Review. If these occur prior to 31st October they will be included in the transport model and impact the locational element. All known changes, prior to the setting of tariffs, impact on the charging bases and the residual tariff.

Table 6 - Contracted and Modelled TEC

(GW)	2015/16	2016/17 Initial forecast	2016/17 April Forecast
Contracted TEC	78.7	77.9	81.7
Modelled TEC	78.7	82.9	79.1

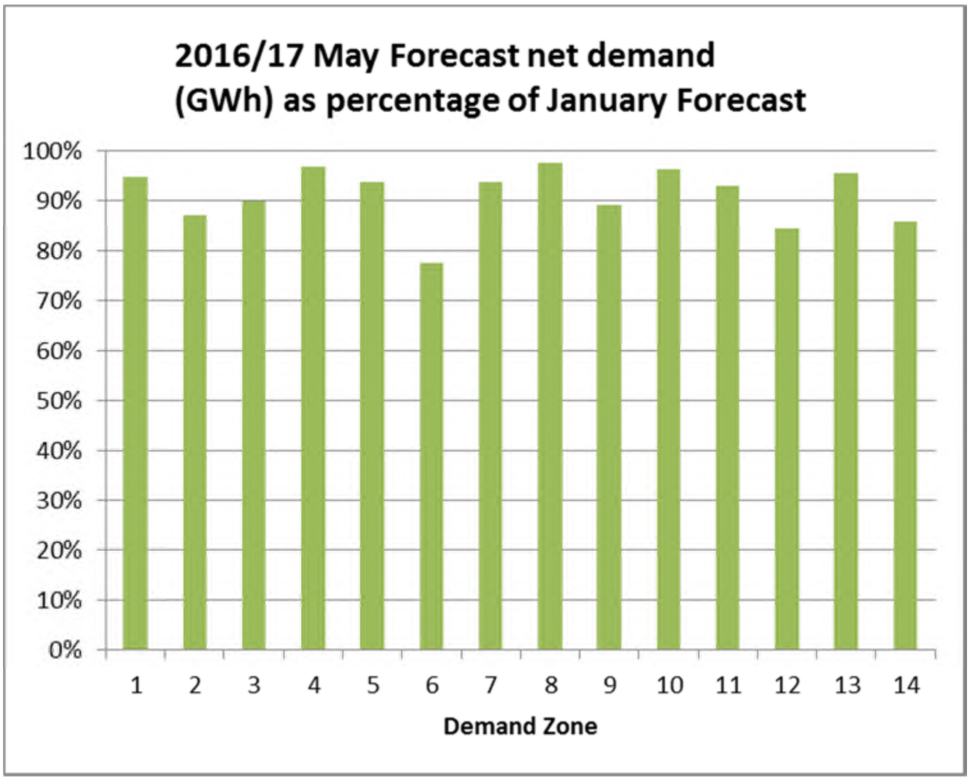
[2]CMP240 reduces the cancellation charge liability for TEC reductions and closures affecting 2016/17 made within 20 business days of the conclusion of the CMP213 (Project Transmit) Judicial Review.

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 and forecasts of demand at directly connected demand sites such as steelworks and railways and some embedded generation. The DNO demand data used in this forecast is based on that provided in 2014 and will remain unchanged before tariffs are finalised in January 2016. These show a decline in demand at peak broadly consistent with what was observed during winter 2014/15.

Embedded generation and directly connected demand forecasts will continue to be updated before tariffs are finalised in January 2016. A summary of changes in the Locational Demand can be found in Table 24 in Appendix C.

Figure 1 - Change in forecast net locational demand



4.1.3 Transmission network

The circuit data has not changed since the January forecast. We expect to update circuit data in the October update.

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. January's forecast and the final revenue upon which 2015/16 tariffs were set are also included for comparison. 2016/17 revenues have been adjusted to reflect changes in actual and forecast inflation since the January forecast. National Grid's revenue also includes £105m for revenue which was not recovered during 2014/15 due to lower net demand and greater embedded generation than anticipated. Further details can be found in Appendix A.

National Grid also collects Network Innovation Competition funding which from 2016/17 is expected to include awards for electricity Distribution as well as Transmission.

Table 7 - Allowed revenue

£m Nominal	2015/16 TNUoS Revenue	2016/17 TNUoS Revenue	
	Jan 2015 Final	**Jan 2015 Initial View**	**May 2015 Update**
National Grid			
Price controlled revenue	*1,780.7*	*1,953.8*	*1,937.0*
Less income from connections	*45.0*	*48.3*	*45.0*
Income from TNUoS	**1,735.7**	**1,905.5**	**1,892.0**
Scottish Power Transmission			
Price controlled revenue	*306.4*	*321.0*	*303.1*
Less income from connections	*10.7*	*10.5*	*8.9*
Income from TNUoS	**295.7**	**310.5**	**294.2**
SHE Transmission			
Price controlled revenue	*341.7*	*343.0*	*333.6*
Less income from connections	*3.5*	*3.6*	*3.5*
Income from TNUoS	**338.2**	**339.5**	**330.1**
Offshore	**248.4**	**269.1**	**265.6**
Network Innovation Competition	**18.8**	**48.4**	**40.5**
Total to Collect from TNUoS	**2,636.7**	**2,873.0**	**2,822.4**

4.2.2 Charging bases for 2016/17

Generation

The generation base for 2016/17 is based on the 13 April 2015 contracted generation background. The contracted background has been adjusted to reflect the probability of existing

Generators reducing their TEC and new projects being delayed. The result of these adjustments is that National Grid's best view is less than the contracted TEC shown in the TEC register. We are unable to breakdown the modelled TEC as some of the information used to derive the data could be commercially sensitive.

The generation charging base is subject to change as we approach January 2016. Whilst the normal deadline for non-chargeable TEC reductions has passed, CMP240 provides a further opportunity for Generators who may want to reduce their TEC in the 20 business days following the conclusion of the CMP213 Judicial Review. In any event a generator has the option of paying a cancellation fee at any time, rather than continuing with TEC for the next year.

Demand

System demand at peak (Triad), Half-Hourly metered demand at Peak and Non-Half-Hourly energy between 4pm and 7pm have been updated from the January forecast to take account of demands over 2014/15. Whilst system demand at peak in 2014/15 was slightly higher than 2013/14 due to colder weather, the underlying reduction in system demand at peak has continued. The proportion of HH demand at system peak fell during 2014/15 reflecting greater output from embedded generation, principally wind. Non-half-hour metered demand also fell throughout 2014/15 reflecting greater efficiency and growth in embedded generation such as solar.

We have therefore reduced our demand forecasts as detailed in Table 8 below. It also shows the impact of P272 which reduces the NHH demand base and increases the HH demand base in 2016/17. We will continue to review the demand charging base and its geographical distribution during 2015. Further updates are likely to include changes based on this work, to revise volume, geographical distribution and the split between NHH and HH.

Table 8 - Charging Base

Charging Base	2015/16	2016/17 Pre-P272 (For info)	2016/17 Post-P272
Generation (GW)	71.5	74.1	74.1
Total Average Triad (GW)	52.4	50.8	50.8
HH Demand Average Triad (GW)	15.0	13.6	17.3
NHH Demand (4pm-7pm TWh)	27.4	26.2	23.7

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. Since interconnectors are not liable for generation or demand TNUoS charges, they 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 the average annual charge paid by Generators to €2.5/MWh. This caps the revenue that can be recovered from generation and therefore revenue increases tend to be borne by demand. The weakening of the Euro has also reduced the revenue that can be recovered from generation thus increasing the amount recovered from demand.

Table 10 shows the forecast generation and demand proportions for 2016/17 with 2015/16 shown for comparison. A 7% risk margin has been applied to the €2.5/MWh limit reflecting year ahead revenue and charging base forecast accuracy and so generation tariffs have been limited to €2.34/MWh. The Euro exchange rate used for setting tariffs is the Office for Budgetary Responsibility March forecast and is now fixed for 2016/17 TNUoS tariffs. However, National Grid will keep the volume of generation and the forecasting margin under review.

Table 10 - Generation and Demand Revenue Properties

		2015/16	2016/17
L	Limit on generation tariff (€/MWh)	2.34	2.34
X	Exchange Rate (€/£)	1.22	1.36
L	Limit on generation tariff (£/MWh)	1.92	1.72
R	Total Revenue (£m)	2,637	2,822
E	Annual generation (TWh)	319.6	318.7
G	% of revenue from generation	23.2%	19.4%
D	% of revenue from demand	76.8%	80.6%
G.R	Revenue recovered from generation (£m)	612	548
D.R	Revenue recovered from demand (£m)	2,025	2,275

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)

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

Typically 75% of offshore revenues are recovered from offshore local tariffs. Therefore if revenue (R) is reduced / increased due to offshore revenue changes then O must also be adjusted by 75%. E.g., if offshore revenues reduce by £10m, reduce R by £10m and O by £7.5m. Table 11 shows the residual calculation.

Table 11 - Residual Calculation

		2015/16	2016/17
R_G	Generator residual tariff (£/kW)	4.81	1.49
R_D	Demand residual tariff (£/kW)	35.63	44.90
G	Proportion of revenue recovered from generation (%)	0.232	0.194
D	Proportion of revenue recovered from demand (%)	0.768	0.806
R	Total TNUoS revenue (£m)	2,637	2,822
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	47.6	225.5
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	157.7	-7.6
O	Revenue recovered from offshore local tariffs (£m)	186.6	175.8
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.1	20.0
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.8	15.9
B_G	Generator charging base (GW)	71.5	74.1
B_D	Demand charging base (GW)	52.4	50.8

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant of £13.662440/MWkm has been updated from the January forecast to reflect changes in actual and forecast RPI.

5 Forecast generation tariffs for 2016/17

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

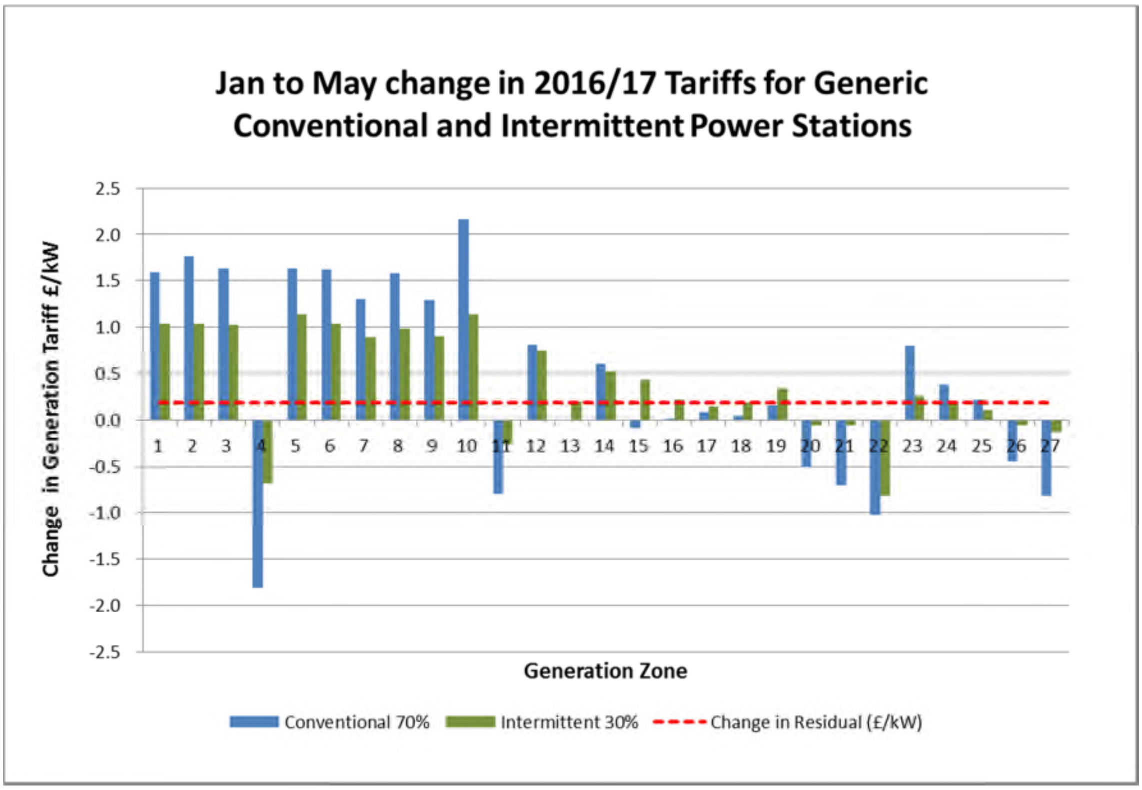
5.1 Wider zonal generation tariffs

Table 12 and Figure 2 show the changes in generation Wider TNUoS tariffs between the January forecast and this forecast for a conventional generator with 70% load factor and an intermittent generator with 30% load factor.

Table 12 - Variation in generation zonal tariffs

Wider Generation Tariffs (£/kW)									
		Conventional 70%			Intermittent 30%			Change in Residual (£/kW)
Zone	Zone Name	2016/17 Jan forecast (£/kW)	2016/17 May Forecast (£/kW)	Change (£/kW)	2016/17 Jan forecast (£/kW)	2016/17 May Forecast (£/kW)	Change (£/kW)	
1	North Scotland	20.63	22.22	1.59	12.48	13.52	1.04	0.19
2	East Aberdeenshire	17.00	18.76	1.76	10.55	11.59	1.03	0.19
3	Western Highlands	18.65	20.29	1.63	11.57	12.59	1.02	0.19
4	Skye and Lochalsh	16.10	14.29	-1.81	13.04	12.35	-0.68	0.19
5	Eastern Grampian and Tayside	16.98	18.61	1.63	10.73	11.88	1.14	0.19
6	Central Grampian	18.71	20.33	1.62	10.65	11.69	1.04	0.19
7	Argyll	19.72	21.03	1.30	13.47	14.36	0.89	0.19
8	The Trossachs	14.83	16.41	1.58	8.46	9.45	0.98	0.19
9	Stirlingshire and Fife	14.31	15.60	1.29	7.85	8.75	0.90	0.19
10	South West Scotland	12.94	15.10	2.16	7.96	9.10	1.14	0.19
11	Lothian and Borders	12.50	11.71	-0.79	5.54	5.27	-0.27	0.19
12	Solway and Cheviot	9.30	10.12	0.82	5.71	6.46	0.75	0.19
13	North East England	8.59	8.59	-0.00	3.85	4.05	0.20	0.19
14	North Lancs and The Lakes	6.62	7.24	0.61	3.80	4.32	0.52	0.19
15	South Lancs, Yorks and Humber	6.21	6.13	-0.09	1.46	1.88	0.43	0.19
16	North Midlands and North Wales	4.89	4.90	0.01	1.33	1.55	0.22	0.19
17	South Lincs and North Norfolk	2.86	2.94	0.08	1.29	1.44	0.15	0.19
18	Mid Wales and The Midlands	2.44	2.48	0.05	1.27	1.46	0.19	0.19
19	Anglesey and Snowdon	7.20	7.35	0.15	1.78	2.12	0.34	0.19
20	Pembrokeshire	6.97	6.47	-0.51	0.28	0.22	-0.06	0.19
21	South Wales	4.23	3.53	-0.70	0.25	0.19	-0.06	0.19
22	Cotswold	-0.71	-1.73	-1.02	-3.88	-4.70	-0.81	0.19
23	Central London	-6.04	-5.24	0.80	-3.22	-2.96	0.26	0.19
24	Essex and Kent	-1.38	-1.00	0.38	2.07	2.25	0.19	0.19
25	Oxfordshire, Surrey and Sussex	-1.95	-1.73	0.22	0.68	0.79	0.10	0.19
26	Somerset and Wessex	-3.25	-3.70	-0.45	0.27	0.20	-0.06	0.19
27	West Devon and Cornwall	-4.24	-5.06	-0.82	-0.37	-0.50	-0.13	0.19

Figure 2 - Variation in Generation Zonal Tariffs



Residual Tariff

The residual element of the tariff has increased by £0.19/kWh. This is due to a reduction in the generation charging base which leads to a higher cost per unit; a reduction in the forecast offshore local revenue, which results in more revenue recovered by the residual tariff; and these are partially offset by a weaker Euro, which results in a lower allowed volume of revenue to be recovered by generation.

Locational Tariff

The general trend to the change in tariffs is an increase in tariffs in the North and a reduction in the South. This is as a result of the changes in both the demand and generation, increasing the North South flows. The impact is more noticeable for conventional generation than intermittent. This is because the more significant increase in tariffs is in the peak element which is only applicable to conventional plant.

There are some obvious exceptions to the trend. Zone 4 has only one generator located within the zone. Small changes in generation and demand within this zone can cause changes in flows which have a significant impact on tariffs.

All zones above the Moyle interconnector are impacted by the change in the way generation and demand are modelled under Transmit, this increases tariffs in Zones 1 to 10.

Zones 20, 21, 22, 26 and 27 cover the whole of the South West. Zones 23, 24 and 25 cover London and the South East. There has been a change in the East West flows increasing tariffs in the East and reducing tariffs in the West.

5.2 Onshore local generation tariffs

Onshore local generation tariffs have been updated from the January forecast to reflect changes in local circuit flows.

5.3 Onshore local substation tariffs

Local substation tariffs have been updated form the January forecast to reflect changes in actual and forecast RPI.

5.4 Offshore local generation tariffs

The local offshore tariffs (substation, circuit, ETUoS) have been updated from the January forecast to reflect changes in actual and forecast RPI.

6 Forecast demand tariffs for 2016/17

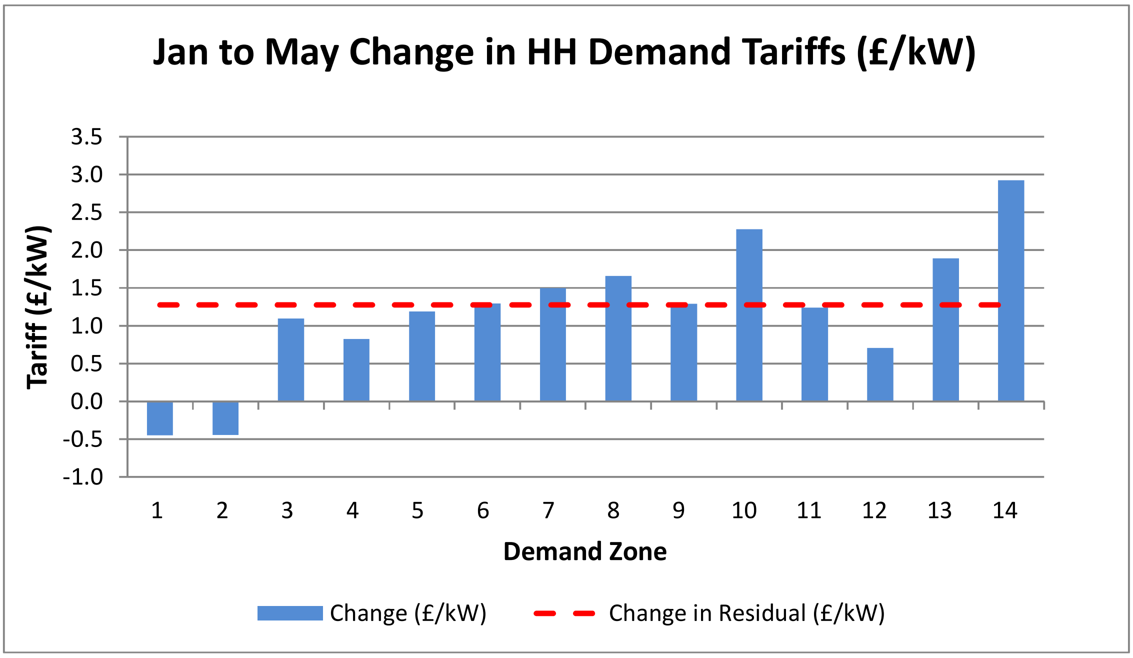
6.1 Half Hour Demand Tariffs

Table 13 and Figure 3 show the difference between the Half-Hourly (HH) demand tariffs forecast in January and this forecast.

Table 13 - Change in HH Demand Tariffs

Zone	Zone Name	2016/17 Jan Forecast (£/kW)	2016/17 May Forecast (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	29.79	29.34	-0.45	1.27
2	Southern Scotland	31.84	31.40	-0.44	1.27
3	Northern	36.29	37.38	1.09	1.27
4	North West	40.09	40.92	0.83	1.27
5	Yorkshire	40.48	41.67	1.19	1.27
6	N Wales & Mersey	39.99	41.28	1.29	1.27
7	East Midlands	43.35	44.85	1.50	1.27
8	Midlands	43.96	45.62	1.66	1.27
9	Eastern	45.68	46.97	1.29	1.27
10	South Wales	41.82	44.09	2.27	1.27
11	South East	48.41	49.65	1.24	1.27
12	London	51.25	51.95	0.71	1.27
13	Southern	49.11	51.00	1.89	1.27
14	South Western	48.38	51.30	2.92	1.27

Figure 3 - Change in HH Demand Tariffs



Residual Tariff

The residual tariff element of HH demand tariffs has increased by £1.27/kW. This is due to a reduction in the demand charging base which leads to a higher cost per unit; and a weaker Euro which results in demand recovering a greater proportion of total revenue.

Locational Tariff

Zones 1 and 2 change is negative as a result of an increase in the residual being netted off with a decrease due to the changes in the generation and demand background.

Changes in the East West flows increase tariffs in zone 10, 13 and 14 and reduce tariffs in zones 11 and 12.

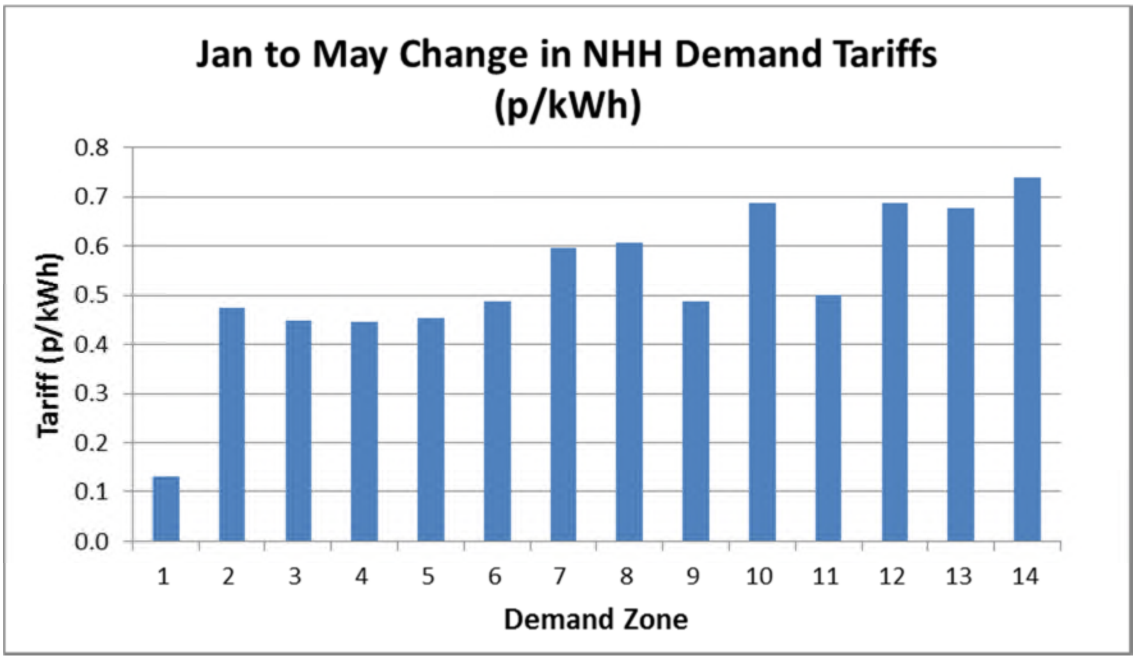
6.2 Non Half-hourly demand tariffs

Table 14 and Figure 4 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in January and this forecast. Similar changes to the HH demand tariffs are seen in NHH tariffs.

Table 14 - NHH Demand Tariff Changes

Zone	Zone Name	2016/17 Jan Forecast (p/kWh)	2016/17 May Forecast (p/kWh)	Change (p/kWh)
1	Northern Scotland	4.21	4.34	0.13
2	Southern Scotland	4.10	4.57	0.47
3	Northern	4.61	5.05	0.45
4	North West	5.32	5.77	0.45
5	Yorkshire	5.65	6.10	0.45
6	N Wales & Mersey	6.30	6.79	0.49
7	East Midlands	5.63	6.23	0.60
8	Midlands	5.92	6.53	0.61
9	Eastern	5.96	6.45	0.49
10	South Wales	5.68	6.37	0.69
11	South East	6.22	6.72	0.50
12	London	6.43	7.12	0.69
13	Southern	6.48	7.16	0.68
14	South Western	6.18	6.92	0.74

Figure 4 - NHH Tariff Demand Changes



7 Sensitivities & Uncertainties for 2016/17

7.1 Transmission revenue requirements

Table 15 illustrates the sensitivity of the forecast tariffs to changes in the revenue collected from TNUoS tariffs. This scenario does not represent a minimum or maximum tariff range.

Table 15 – Impact of change in TNUoS Revenue

£50m increase in revenue recovered from TNUoS tariffs	
Change in Generation Tariffs (£/kW)	Nil
Change in HH Demand Tariffs (£/kW)	+0.98
Change in NHH Demand Tariffs (p/kWh)	+0.14

7.2 Demand charging base

An increase in the demand charging base decreases tariffs and vice versa. Table 16 shows the impact of a 500MW decrease in peak system demand with the corresponding reduction in HH Demand. Table 17 shows the impact of a 0.5TWh decrease in NHH demand with no change to peak system demand. For simplicity the same proportion of change is assumed across all zones.

Table 16 - Impact of change to peak system demand

Change to peak system demand and pro-rata change in HH demand	Change to HH Average Tariff (£/kW)
-500MW	0.44

Table 17 - Impact of change to NHH demand

Change to NHH demand with no change to peak system demand	Change to Average NHH Tariff (p/kWh)
-0.5TWh	0.14

7.3 Generation charging base

The tariffs presented in this document are based upon the contracted generation background for 2016/17 as of April 2015. The locational element of tariffs will be finalised using the contracted background as at 31 October 2015. However the residual element of generation tariffs may continue to be adjusted up to when tariffs are finalised in January 2016, to reflect changes in the charging base.

An increase in the generation charging base decreases tariffs and vice versa. Table 18 shows the impact of a 1GW decrease in the generation charging base. For simplicity this has been spread across all zones.

Table 18 - Impact of change to generation

Change to generation charging base	Change to Average Generation Tariff (£/kW)
-1000MW	0.06

7.4 Circuit parameters

The October update on TNUoS tariffs will revise the circuit parameters.

8 Tools and Supporting Information

8.1 Further information

We are keen to ensure that customers understand the current charging arrangements and the reasons why tariffs change from year to year. 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.

Team phone		01926 654633
Mary Owen	mary.owen@nationalgrid.com	01926 653845
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David Russell	david.russell@nationalgrid.com	01926 655654

8.2 Charging forums

We will be hosting a webinar on Friday 15th May 2015 to present the material in this forecast and answer questions in an open forum. Please contact us if you wish to participate so that we may send you details.

8.3 Charging models

We can provide a copy of our charging model. If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

8.4 Numerical data

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

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

Appendices

Appendix A: Revenue Tables

Appendix B: Generation changes for 2016/17

Appendix C: Locational Demand changes

Appendix D: Generation Zones

Appendix E: 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. Forecasts are also provided for offshore networks with forecasts by National Grid where these have yet to be transferred to the Offshore Transmission Owner or are still to be constructed.

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 other 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 TOs 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 TOs 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 revenues forecasts reflect the figures authorised by Ofgem in the RIIO-T1 or offshore price controls.

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

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

Table 19 - National Grid Revenue Forecast

National Grid Revenue Forecast				Updated:	24/04/2015			
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year					2014/15	2015/16	2016/17	Notes
Actual RPI							-	April to March average
RPI Actual		RPIAt	3A				-	Office of National Statistics
Assumed Interest Rate		It	3A		0.50%	0.70%	1.10%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	1,443.8	1,475.6	1,571.4	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL	-5.5	-114.4	-100.0	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL	-0.5	4.7	-20.7	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3A	ALL	3.1%	2.5%	1.2%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	3.1%	2.4%	2.6%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	3.0%	3.2%	3.2%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	3A	ALL	1.2051	1.2267	1.2412	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1732.7**	**1675.5**	**1800.7**	
Pass-Through Business Rates	B1	RBt	3B	ALL		1.2	1.4	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL	0.1	0.0	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt	3B	NG		2.0	2.3	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	3B	NG		3.8	0.0	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	3B	NG	0.0	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	3B	NG	312.2	295.7	294.2	14/15 & 15/16 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	3B	NG	214.0	338.2	330.1	14/15 & 15/16 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	218.4	248.4	265.6	14/15 & 15/16 Charge setting. Later from OFTO Calculation.
Embedded Offshore Pass-Through	B9	OFETt	3B	NG	0.4	0.6	0.7	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**3B**	**ALL**	**745.1**	**890.0**	**894.2**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL		2.4	2.3	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL		8.7	7.7	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL		2.8	2.8	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL		0.0	0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**13.9**	**12.8**	
Network Innovation Allowance	D	NIAt	3H	ALL	10.9	10.6	11.3	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	3I	NG	17.8	18.8	40.5	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt	3F	ALL			3.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	16.0	15.7	-0.5	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	3A	NG	2.0	0.8	0.0	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	3A	NG	-0.3	0.1	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL		56.4	105.3	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**		**ALL**	**2524.3**	**2681.6**	**2867.3**	
Termination Charges	B5			NG	0.0	0.0	0.0	
Pre-vesting connection charges	P			ALL	47.0	45.0	45.0	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**			**NG**	**2477.3**	**2636.7**	**2822.4**	
Forecast percentage change to Maximum Revenue M				**NG**	**0.0%**	**6.2%**	**6.9%**	
Forecast percentage change to TNUoS Collected Revenue T				**NG**	**0.0%**	**6.4%**	**7.0%**	

Table 20 - Scottish Power Revenue Forecast

Scottish Power Transmission Revenue Forecast				Updated:	07/04/2015			
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year					2014/15	2015/16	2016/17	Notes
Actual RPI							-	April to March average
RPI Actual		RPIAt					-	Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.50%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	237.0	258.6	244.7	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL	6.2	-20.3	-20.2	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL	-0.1	0.9	-3.7	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.2051	1.2266	1.2412	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**292.9**	**293.4**	**274.1**	
Pass-Through Business Rates	B1	RBt	3B	ALL		-19.1	-4.3	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL	0.0	0.0	0.0	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**-19.1**	**-4.3**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL		2.6	1.2	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL		1.9	0.6	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL		-0.2	0.0	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL		0.0	0.0	Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE		0.0	0.0	Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**4.3**	**1.7**	
Network Innovation Allowance	D	NIAt	3H	ALL	1.0	1.2	0.8	Licensee Actual/Forecast/Budget
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	29.2	18.0	30.6	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL		8.6	0.2	Calculated by Licensee
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**323.1**	**306.5**	**303.1**	
Excluded Services	P	EXCt		SP, SHE	7.7	8.0	9.7	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	18.5	18.8	18.6	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**		**NG**	**312.3**	**295.7**	**294.2**	**General System Charge**
Forecast percentage change to TNUoS Collected Revenue T				**ALL**	**0.0%**	**-5.3%**	**-0.5%**	

Table 21 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast				Updated:	16/12/2014			
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year					2014/15	2015/16	2016/17	Notes
Actual RPI							-	April to March average
RPI Actual		RPIAt					-	Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.50%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	111.5	124.1	123.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL	8.7	88.9	89.0	Forecast of cummulativce MOD impacts, excl non approved
RPI True Up	A3	TRUt	3A	ALL	0.0	0.5	-0.3	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.2051	1.2266	1.2412	Using HM Treasury Forecast - 2015/16 updated by SHET
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**144.9**	**262.0**	**263.5**	
Pass-Through Business Rates	B1	RBt	3B	ALL	0.0	-0.7	-15.7	RBt rebate received in 2014/15, pass through in 2016/17
Temporary Physical Disconnection	B2	TPDt	3B	ALL	0.0	0.6	0.0	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**-0.1**	**-15.7**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL		1.2	0.0	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL		1.6	0.0	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL		-0.1	0.0	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL		0.0	0.0	Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE		0.0	0.0	Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**2.7**	**0.0**	
Network Innovation Allowance	D	NIAt	3H	ALL	1.8	1.8	1.8	Licensee Actual/Forecast
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	72.2	81.3	82.6	Excludes Asset Adjusting Events impacts
Compensatory Payments Adjustment	J	SHCPt	3C	SHE	0.0	0.4	0.0	Licensee Actual/Forecast/Budget
Correction Factor	K	-Kt	3A	ALL		-1.5	1.4	Latest Forecast
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**218.9**	**346.5**	**333.6**	
Excluded Services	P	EXCt		SP, SHE	0.0	0.0	0.0	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	3.5	3.5	3.5	Post-Vesting, Pre-BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**		**NG**	**215.4**	**343.0**	**330.1**	General System Charge
Forecast percentage change to TNUoS Collected Revenue T				**ALL**	**0.0%**	**59.3%**	**-3.8%**	

Table 22 - Offshore Transmission Owner Revenues

Offshore Transmission Revenue Forecast	24/04/2015			
Description	Yr t-1	Yr t	Yr t+1	
Regulatory Year	2014/15	2015/16	2016/17	Notes
Barrow	5.5	5.6	5.7	Current revenues plus indexation
Gunfleet	6.9	7.0	7.1	Current revenues plus indexation
Walney 1	12.5	12.8	12.9	Current revenues plus indexation
Robin Rigg	7.7	7.9	8.0	Current revenues plus indexation
Walney 2	12.9	13.2	13.4	Current revenues plus indexation
Sheringham Shoal	18.9	19.5	19.7	Current revenues plus indexation
Ormonde	11.6	11.8	12.0	Current revenues plus indexation
Greater Gabbard	26.0	26.6	26.9	Current revenues plus indexation
London Array	37.6	39.2	37.9	Current revenues plus indexation
Thanet	78.9	17.5	17.7	Current revenues plus indexation
Lincs		25.6	25.4	Current revenues plus indexation
Gwynt y mor		26.3	25.6	Current revenues plus indexation
West of Duddon Sands		35.3	53.2	National Grid Forecast
Humber Gateway				National Grid Forecast
Westermost Rough				National Grid Forecast
Offshore Transmission Pass-Through (B7)	**218.4**	**248.4**	**265.6**	

Appendix B : Generation changes for 2016/17

Table 23 shows TEC changes notified between December 2014 (used for the January forecast) and April 2015 (used for this forecast.) Generators less than 100MW with Bilateral Embedded Generator Agreements are included in DNO Week 24 Demand data and are shown here as zero.

Table 23 - Generation TEC Changes

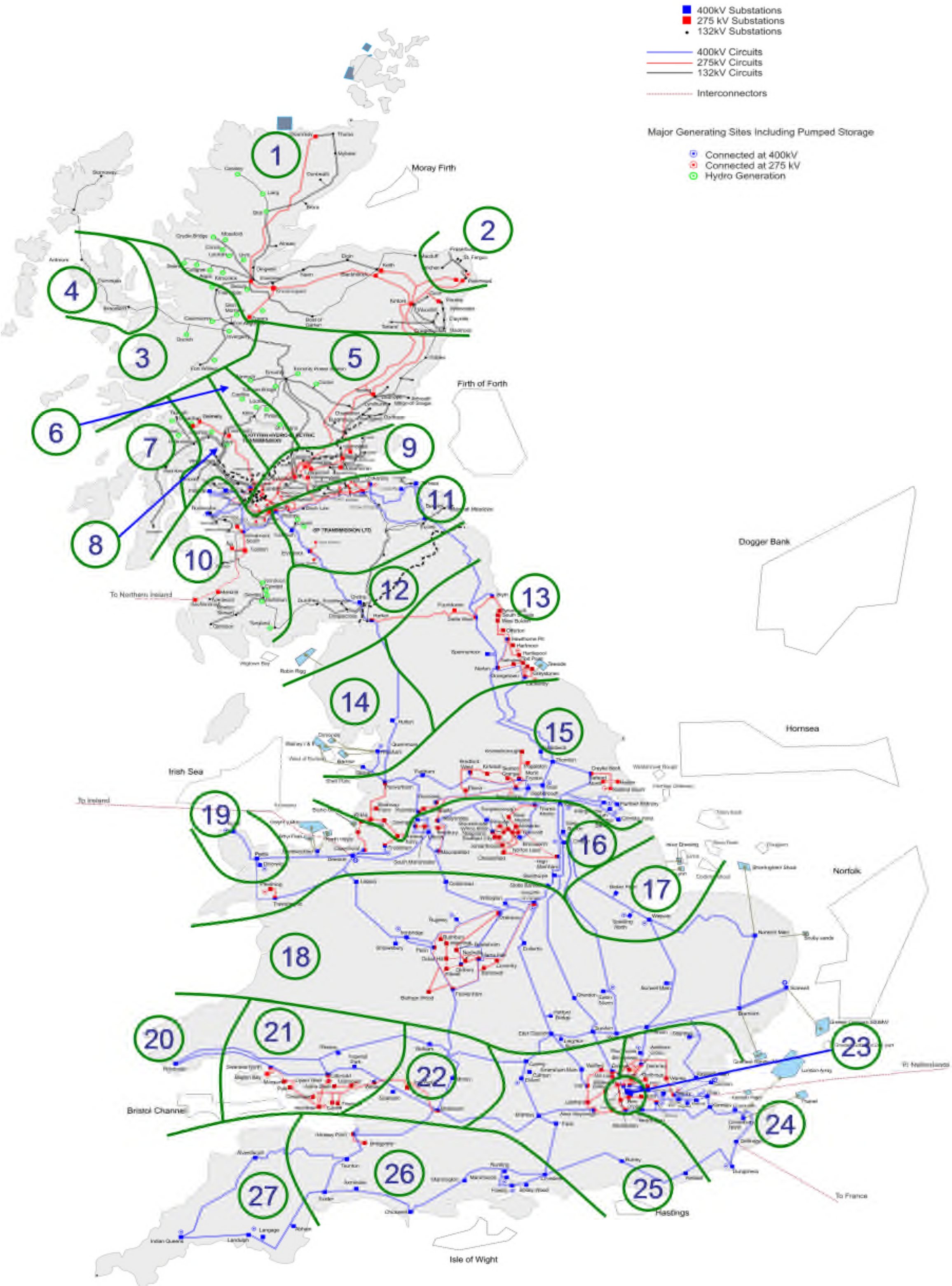
Station	Agreement Type	Node	Zone	TEC Register 03/12/2014	TEC Register 13/04/2015	MW Change
Abernedd Power Station	BCA	BAGB20	21	500	0	-500
Aikengall II Windfarm	BCA	WDOD10	11	108	140	32
Airies Wind Farm	BCA	GLLU1Q	10	0	35	35
Barking	BCA	BARK20_LPN	24	950	0	-950
Barry Power Station	BEGA	ABTH20	21	235	0	-235
Brigg	BEGA	KEAD40	16	155	0	-155
C.Gen Killingholme North Power Station	BCA	KILL40	15	490	0	-490
Clyde North	BCA	CLYN2Q	11	332	375	43
Clyde South	BCA	CLYS2R	11	180	129	-51
Deeside	BCA	CONQ40	16	515	260	-255
Ewe Hill	BCA	EWEH1Q	11	18	39	21
Griffin Wind Farm	BCA	GRIF1S	5	204	189	-15
Gwynt Y Mor Offshore Wind Farm	BCA	BODE40	16	565	574	9
Hadyard Hill	BCA	HADH10	10	117	100	-17
Harelaw	BCA	NEIW10	11	80	0	-80
Ironbridge	BCA	IRON40	18	680	0	-680
Killingholme	BCA	KILL40	15	900	0	-900
Killingholme 2	BCA	KILL40	15	665	0	-665
Lynemouth Power Station	BEGA	BLYT20	13	376	0	-376
Newfield Wind Farm	BCA	NEWF1Q	11	53	0	-53
Peterborough	BEGA	WALP40_EME	17	245	0	-245
Rampion Offshore Wind Farm	BCA	BOLN40	25	664	332	-332
Rugeley	BCA	RUGE40	18	1,018	980	-38
Sizewell B	BCA	SIZE40	18	1,212	1,216	4
South Humber Bank	BCA	SHBA40	15	1,285	540	-745
Uskmouth	BCA	USKM20	21	0	115	115
Walney Extension Power Station A Offshore Wind Farm	BCA	HEYS40	14	330	0	-330
Walney Extension Power Station B Offshore Wind Farm	BCA	HEYS40	14	330	0	-330
Total				12,206	5,023	-7,183

Appendix C : Locational Demand changes

Table 24 - Week 24 Demand and Negative Generation

Zone	Zone Name	2016/17 Initial View Net Demand (GWh)	2016/17 April Forecast Net Demand (GWh)	% Change
1	Northern Scotland	896	848	-5%
2	Southern Scotland	3,842	3,337	-13%
3	Northern	2,937	2,636	-10%
4	North West	4,152	4,009	-3%
5	Yorkshire	4,889	4,582	-6%
6	N Wales & Mersey	2,699	2,092	-22%
7	East Midlands	5,301	4,966	-6%
8	Midlands	4,528	4,414	-2%
9	Eastern	6,268	5,583	-11%
10	South Wales	1,995	1,920	-4%
11	South East	3,882	3,609	-7%
12	London	5,515	4,661	-15%
13	Southern	6,279	5,995	-5%
14	South Western	2,935	2,518	-14%
Total		56,117	51,171	-9%

Appendix D : Generation Zones



Appendix E : Demand Zones