nationalgrid

Tariff Information Paper

July 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 third of a series of updates that National Grid will publish throughout the year.

National Grid will be hosting a webinar on this report on Thursday 30 July 2015 at 1pm. Please contact us if you wish to participate using the details overleaf.

25 November 2015

V2.1

Contents

Any Questions?

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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 provides our latest forecast of 2016/17 TNUoS tariffs.

The locational element of TNUoS tariffs has changed since the previous forecast and from 2015/16. This is predominantly due to the forecast capacity reduction of Longannet Power Station, based on their REMIT data. The effect is a reduction in generation tariffs in the North and an increase in the South. Since the locational element of demand tariffs mirror generation tariffs, the demand tariffs see the opposite effect.

Revenue recovered from TNUoS on behalf of all Transmission Owners has reduced by £9.8m to £2,812.6m, largely due to lower actual and forecast inflation.

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. The claim for Judicial Review was dismissed on 23 July 2015. We are hoping to open the window for TEC reductions established under CMP240 towards the end of August. This will establish a firmer picture of the background and reduce uncertainty across the industry. 2016/17 also sees the expiration of the small generator discount under National Grid's licence. CMP239 looks to continue the small Generator discount in a limited form and so this may be included in future forecasts.

We have reduced our forecast of peak demand from 50.8GW to 49.3GW in line with the forecasts in the 2015 Future Energy Scenarios publication. This reduces the customer base and so demand tariffs will increase to recover allowed revenue. The zonal demand has also been reforecast for total triad demand, HH customer demand and NHH consumption. This is apparent in the NHH demand tariffs with zones being affected differently depending on changes in forecast demand and distributed generation.

The updated demand forecast also impacts on the G/D split. This forecast shows a reduction in generation volumes as a result of reduced demand, increased interconnector imports and better representation of distributed generation in our models.

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. If there are any exceptional events that might have a material impact on the forecast we will consider updating the forecast earlier than planned.

If you need further support on forecasts tariffs or have any comments on how this report can be improved please do not hesitate to contact Stuart Boyle. These tariffs are established under the methodology set out in the CUSC, if you have any proposals for improvements we are happy to assist in the development of these or facilitate the development through the Transmission Charging Methodologies Forum.

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 May forecast.

2.1 Generation Tariffs 2016/17

Table 1 - Wider Generation Tariffs

Under the Transmit methodology each generator has its own load factor. The 70% and 30% 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	-2.62	10.02	6.73	0.21	11.33	9.95
2	East Aberdeenshire	-1.55	3.81	6.73	0.21	8.06	8.08
3	Western Highlands	-2.79	7.87	6.73	0.21	9.66	9.30
4	Skye and Lochalsh	-6.77	7.87	7.97	0.21	6.92	10.54
5	Eastern Grampian and Tayside	-2.89	6.53	6.44	0.21	8.33	8.61
6	Central Grampian	-0.42	6.32	6.34	0.21	10.56	8.45
7	Argyll	-1.25	4.02	10.58	0.21	12.36	12.00
8	The Trossachs	-0.83	4.02	5.21	0.21	7.40	6.62
9	Stirlingshire and Fife	-2.55	1.71	4.69	0.21	3.54	5.41
10	South West Scotlands	-1.35	3.86	5.02	0.21	6.59	6.39
11	Lothian and Borders	0.34	3.86	2.26	0.21	5.52	3.63
12	Solway and Cheviot	-1.34	2.22	2.41	0.21	2.84	3.29
13	North East England	0.76	2.11	-0.67	0.21	1.77	0.17
14	North Lancashire and The Lakes	1.73	2.11	2.21	0.21	5.63	3.06
15	South Lancashire, Yorkshire and Humber	4.44	1.37		0.21	5.61	0.62
16	North Midlands and North Wales	3.92	0.49		0.21	4.48	0.36
17	South Lincolnshire and North Norfolk	2.27	0.41		0.21	2.77	0.33
18	Mid Wales and The Midlands	1.42	0.72		0.21	2.14	0.43
19	Anglesey and Snowdon	4.68	1.92		0.21	6.23	0.79
20	Pembrokeshire	8.90	-2.40		0.21	7.43	-0.51
21	South Wales & Gloucester	6.26	-2.47		0.21	4.75	-0.53
22	Cotswold	3.08	3.13	-5.55	0.21	-0.07	-4.40
23	Central London	-2.64	3.13	-5.09	0.21	-5.32	-3.94
24	Essex and Kent	-3.55	3.13		0.21	-1.14	1.15
25	Oxfordshire, Surrey and Sussex	-1.07	-1.39		0.21	-1.83	-0.20
26	Somerset and Wessex	-1.12	-2.47		0.21	-2.64	-0.53
27	West Devon and Cornwall	0.15	-3.78		0.21	-2.28	-0.92

Table 2 - Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.18	0.10	0.07
<1320 MW	Redundancy	0.40	0.25	0.18
>=1320 MW	No redundancy		0.33	0.24
>=1320 MW	Redundancy		0.54	0.39

Table 3 - Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.89	Deanie	2.58	Kilbraur	1.05
Afton	2.11	Dersalloch	3.86	Kilgallioch	0.95
Aigas	0.59	Didcot	0.46	Kilmorack	0.18
Aikengall II	1.42	Dinorwig	2.18	Langage	0.60
An Suidhe	0.85	Dudgeon Offshore Wind Farm	-0.34	Lochay	0.33
Arecleoch	3.22	Dumnaglass	3.28	Luichart	1.03
Baglan Bay	0.66	Dunlaw Extension	5.38	Marchwood	0.07
Beinneun Wind Farm	-4.44	Edinbane	6.20	Margee	0.86
Black Craig	1.11	Ewe Hill	4.76	Mark Hill	0.79
Black Law	0.91	Fallago	0.17	Millennium Wind	0.00
Blacklaw Extension	1.99	Farr Windfarm	2.17	Mossford	1.80
Bodelwyddan	0.10	Ffestiniogg	0.23	Nant	-1.11
Brochloch	1.08	Finlarig	0.29	Neilston	-2.16
Carraig Gheal	3.99	Foyers	0.69	Newfield	3.53
Carrington	0.00	Glendoe	1.67	Rhigos	0.11
Clyde (North)	0.10	Glenmoriston	1.20	Rocksavage	0.02
Clyde (South)	0.11	Gordonbush	1.18	Saltend	0.30
Coalburn	0.06	Griffin Wind	1.72	South Humber Bank	0.37
Corriegarth	2.30	Hadyard Hill	2.51	Spalding	0.25
Corriemoillie	2.49	Harestanes	4.81	Strathy Wind	5.14
Coryton	0.05	Hartlepool	0.54	Ulzieside	9.50
Cruachan	1.61	Hedon	0.18	Whitelee	0.10
Crystal Rig	0.30	Hornsea	0.14	Whitelee Extension	0.27
Culligran	1.57	Invergarry	1.29		

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 Mor	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	44.51	5.63
2	Southern Scotland	43.99	6.39
3	Northern	45.58	6.52
4	North West	44.31	5.67
5	Yorkshire	43.80	6.24
6	N Wales & Mersey	43.73	6.07
7	East Midlands	46.57	6.20
8	Midlands	47.41	6.20
9	Eastern	48.54	6.35
10	South Wales	44.03	6.13
11	South East	51.12	6.52
12	London	53.75	6.83
13	Southern	51.87	6.31
14	South Western	50.38	6.61

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 where local connections are single circuit and vary from project to project. These charges are therefore locational and specific to individual Generators. For offshore Generators, these local charges reflect OFTO revenue allowances.

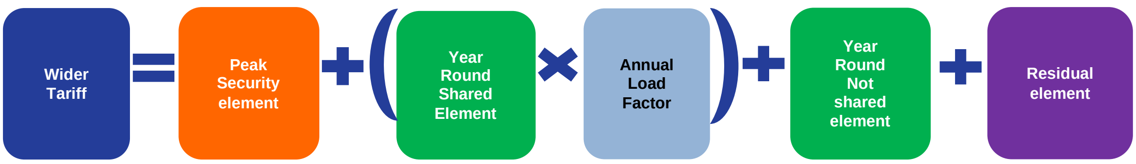
3.2 Project TransmiT

On conclusion of Ofgem's Significant Code Review of gas and electricity transmission charging arrangements known as Project TransmiT, National Grid was 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.

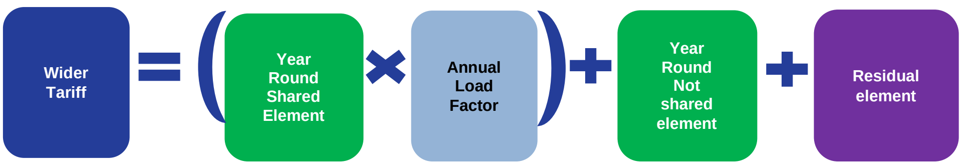
RWE raised a Judicial Review of the decision to implement CMP213. On 23rd of July 2015 we were informed that the claim for Judicial Review was dismissed. This forecast is based on the approved CMP213 methodology which National Grid has been directed to implement.

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



Each generator has a specific annual load factor based on its performance over the last five years. Where new plant does not have a five year history, generic load factors specific to the technology are used. The load factors in this forecast are based on the previous figures published on our web site in December 2013[*]. We will refresh our calculation of individual station load factors later this year. Once updated this may affect overall revenue recovery which would have an impact on the residual but would not affect the locational signals.

3.3 P272, P322 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. The subsequent amendment P322 has revised the completion date for P272 to 1 April 2017. Therefore the affected NHH demand will still be in transition during 2016/17 rather than fully transitioned as we forecast in May.

Connection and Use of System Code Modification Proposal 241 (CMP241) was approved by Ofgem on 30 March 2015.   CMP241 treats metering classes E, F and G as NHH rather than HH during the transition. By default, those meters already transitioned by the start of each charging year and those meters transitioning during the charging year will be treated as NHH.

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

However, suppliers may elect for meters already transitioned by the start of the charging year to be treated as HH.

Following the extension of the implementation date to 1 April 2017, the number of meters that may have transitioned by 1 April 2016 is likely to be significant and electing for them to be treated as HH would be unmanageable from both Suppliers' and National Grid's perspective. National Grid has therefore raised a modification[†] that will treat all meters that transitioned during 2015/16 as NHH during 2016/17. The small number of meters that had already transitioned by 1 April 2015 would still have the option of electing to be treated as HH.

The combined effect of these modifications means that there will be negligible change to the proportion of chargeable HH demand compared to NHH demand in 2016/17. We have therefore removed the P272 adjustment that was included in our May forecast.

[†] **CMP247** - 'TNUoS Demand Charges during the implementation of BSC Modification P272 following the approval of BSC Alternative Modification P322'

4 Updates to the Charging Model for 2016/17

Since our forecast in April we have updated: total revenue, contracted generation, chargeable generation, generator volumes, locational demand and chargeable demand. 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 6 June 2015 and any publicly available information, e.g. individual REMIT submissions. Table 21 in Appendix B shows the changes in contracted Transmission Entry Capacity (TEC) since the May forecast. The locational element of tariffs will be fixed using the contracted background on 31 October 2015[‡]. This forecast uses our best view of the contracted generation on that date and is lower due to a number of plant closures and delays to new projects that we are anticipating. We are unable to fully breakdown our modelled TEC as some of the information used to derive it could be commercially sensitive.

Table 6 - Contracted and Modelled TEC

(GW)	2015/16	2016/17 Initial forecast	2016/17 May Forecast	2016/17 July Forecast
Contracted TEC	78.7	88.5	81.7	79.7
Modelled TEC	78.7	82.9	79.1	71.8

The normal deadline for non-chargeable TEC reductions has passed, but Generators have the option of notifying and paying a cancellation fee at any time. However, CMP240 provides a further non-chargeable opportunity for Generators who may want to reduce their TEC in the 20 business days following conclusion of the CMP213 Judicial Review. If notified before 31 October they will be reflected in the transport model and charging base and impact both the locational and residual tariff elements. We expect that changes after 31 October but before tariffs are set in January will only affect the charging base and residual tariff elements.

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

There have been reports in the press that Scottish Power's Longannet Power Station will be closing. Longannet is currently contracted to have TEC in 2016/17 but REMIT data on Scottish Power's website states closure is likely[§]. We have therefore removed Longannet from this forecast to show the impact on locational signals. Please note that if Longannet closure is notified after 31 October 2015 then it is likely that it will be included in the transport model but may not be included the charging base. The tariffs under this scenario are shown in Appendix D.

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, railways and some embedded generation. DNO demand data was updated in May to that provided in 2014 and will remain unchanged before tariffs are finalised in January 2016. However, Directly Connected Demand and embedded generation may still be revised.

4.1.3 Transmission network

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

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 2016/17 revenues are slightly lower than the May forecast to reflect lower actual and forecast inflation. Further details can be found in Appendix A.

No Offshore Transmission Owners are currently expected to be appointed during 2016/17. Offshore revenue therefore reflects already appointed offshore transmission owners plus West of Duddon Sands, Humber Gateway and Westermost Rough which are expected to be appointed during 2015/16. There is a risk of any of these appointments slipping into 2016/17 in which case 2016/7 revenue could vary (positively or negatively) from this forecast.

National Grid also collects Network Innovation Competition funding which from 2016/17 is expected to include awards for electricity Distribution as well as Transmission. The awards will be announced by Ofgem in November 2015.

[§] European Regulation (EU) 1227/2011 on wholesale energy market integrity and transparency (REMIT) requires generators to publish information on their availability. Scottish Power's data is published on their website:

http://www.scottishpower.com/pages/scottishpower_assets_remit.asp

Table 7 - Allowed revenue

£m Nominal	2015/16 TNUoS Revenue	2016/17 TNUoS Revenue		
	Jan 2015 Final	Jan 2015 Initial View	May 2015 Update	Jul 2015 Update
National Grid				
Price controlled revenue	*1,780.7*	*1,953.8*	*1,937.0*	*1,938.8*
Less income from connections	*45.0*	*48.3*	*45.0*	*45.0*
Income from TNUoS	**1,735.7**	**1,905.5**	**1,892.0**	**1,893.9**
Scottish Power Transmission				
Price controlled revenue	*306.4*	*321.0*	*303.1*	*302.3*
Less income from connections	*10.7*	*10.5*	*8.9*	*8.9*
Income from TNUoS	**295.7**	**310.5**	**294.2**	**293.4**
SHE Transmission				
Price controlled revenue	*341.7*	*343.0*	*333.6*	*329.0*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.5*
Income from TNUoS	**338.2**	**339.5**	**330.1**	**325.5**
Offshore	**248.4**	**269.1**	**265.6**	**259.3**
Network Innovation Competition	**18.8**	**48.4**	**40.5**	**40.5**
Total to Collect from TNUoS	**2,636.7**	**2,873.0**	**2,822.4**	**2,812.6**

4.2.2 Critical Investments

Ofgem has recently published its decision not to change the opening asset value of Scottish Power's Sloy project. Ofgem is also consulting on the opening asset value of Scottish Power's B5 boundary reinforcement and is proposing not to change the value. These projects are included within Scottish Power's Transmission Investment for Renewable Generation (TIRG) revenue allowances.

4.2.3 Charging bases for 2016/17

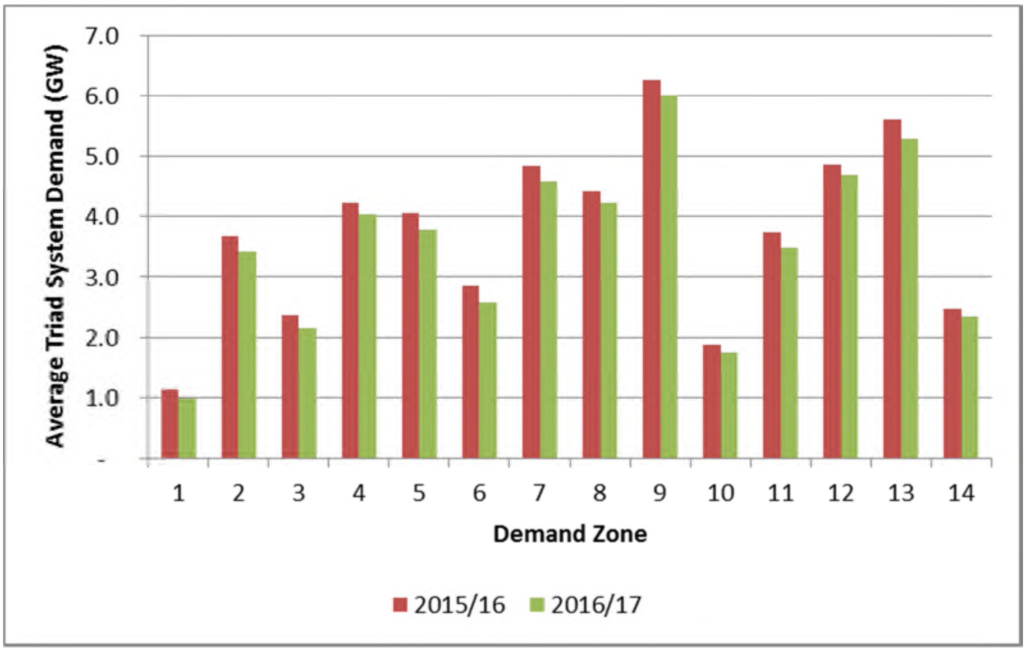
Generation

Whilst the locational element of TNUoS tariffs is expected to be fixed using the contracted background on 31 October 2015, the generation charging base may continue to change after this date. The generation charging base and the residual element of tariffs is therefore based upon National Grid's view of what generation will be connected in 2016/17. We currently forecast the generator charging base will be less than the contracted TEC as at 31 October and therefore less than that included in the Transport model.

Demand

We have reduced our forecast of system demand at peak (Triad) in Winter 2016/17 from 50.8GW in the May forecast to 49.3GW in this forecast. This is in line with the 2015 Future Energy Scenarios published this month. The locational profile of demand at system peak has also been updated as shown in Figure 1. We have reduced demand in all zones to reflect the lower system demand at peak with slight variations between zones reflecting recent growth in embedded generation. Further detail can be found in Appendix C.

Figure 1 - Geographical Distribution of Average Triad Demand



Forecast Half-Hourly metered demand at Peak and Non-Half-Hourly energy between 4pm and 7pm have been increased slightly to reflect information from the 2014/15 initial demand reconciliation. However, we are continuing to review these forecasts and expect to provide a further update in October.

The combined effect of Balancing & Settlement Code (BSC) and Connection and Use of System Code (CUSC) modifications[**] associated with the migration of demand profile classes 5 to 8 from Non-Half-Hour (NHH) metered to half-Hour (HH) metered means we are no longer forecasting any effect on these demand charging bases. We have therefore removed the adjustments that were included in our May forecast. The revenue recovered from the transferring demand is broadly similar whether treated as HH or NHH demand so there is negligible impact on tariffs.

[**] The Balancing & Settlement Code amendments are P272 and P322. The Connection & Use of System Code amendments are CMP241 and a further modification expected to be raised by National Grid.

Table 8 - Charging Base

Charging Base	2015/16	2016/17
Generation (GW)	71.5	67.5
Total Average Triad (GW)	52.4	49.3
HH Demand Average Triad (GW)	15.0	14.2
NHH Demand (4pm-7pm TWh)	27.4	26.6

4.2.4 Adjustments for Interconnectors

When modelling flows on the transmission system, interconnectors are not included in the peak model but are included in the year round model. Since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases, see Table 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

4.2.5 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, the annual volume of generation and the sterling value of a Euro.

The volume of generation used in May's forecast was based on the Future Energy Scenarios (FES) publication in 2014 whereas this forecast is based on the 2015 publication. The annual volume of generation is forecast to be lower due to lower demands, increased imports which offset GB generation and improvements in the economic modelling of distributed generation.

As prescribed by the Use of System charging methodology, the sterling value of a Euro is taken from the Economic and Fiscal Outlook published by the Office of Budgetary Responsibility in March 2015 and is unchanged from the May forecast.

The error margin for generation volume and revenue uncertainty is unchanged at 7% but will be kept under review and may change for the October forecast.

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%	7%
ER	Exchange Rate (€/£)	1.22	1.36
MAR	Total Revenue (£m)	2,637	2,813
GO	Gerneration Output (TWh)	319.6	268.0
G	% of revenue from generation	23.2%	16.3%
D	% of revenue from demand	76.8%	83.7%
G.R	Revenue recovered from generation (£m)	612	458
D.R	Revenue recovered from demand (£m)	2,025	2,354

4.2.6 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 £198.1m which is included in the revenue recovered from generation.

Table 11 - Residual Calculation

		2015/16	2016/17
R_G	Generator residual tariff (£/kW)	4.77	0.21
R_D	Demand residual tariff (£/kW)	35.69	47.77
G	Proportion of revenue recovered from generation (%)	23.1%	16.3%
D	Proportion of revenue recovered from demand (%)	76.9%	83.7%
R	Total TNUoS revenue (£m)	2,637	2,813
Z_G	Revenue recovered from the locational element of generator tariffs (£m)	47.6	213.1
Z_D	Revenue recovered from the locational element of demand tariffs (£m)	157.7	-1.5
O	Revenue recovered from offshore local tariffs (£m)	186.6	198.1
L_G	Revenue recovered from onshore local substation tariffs (£m)	20.1	17.9
S_G	Revenue recovered from onshore local circuit tariffs (£m)	13.8	14.7
B_G	Generator charging base (GW)	71.5	67.5
B_D	Demand charging base (GW)	52.4	49.3

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant has decreased to £13.371389/MWkm from the May forecast to reflect lower 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.

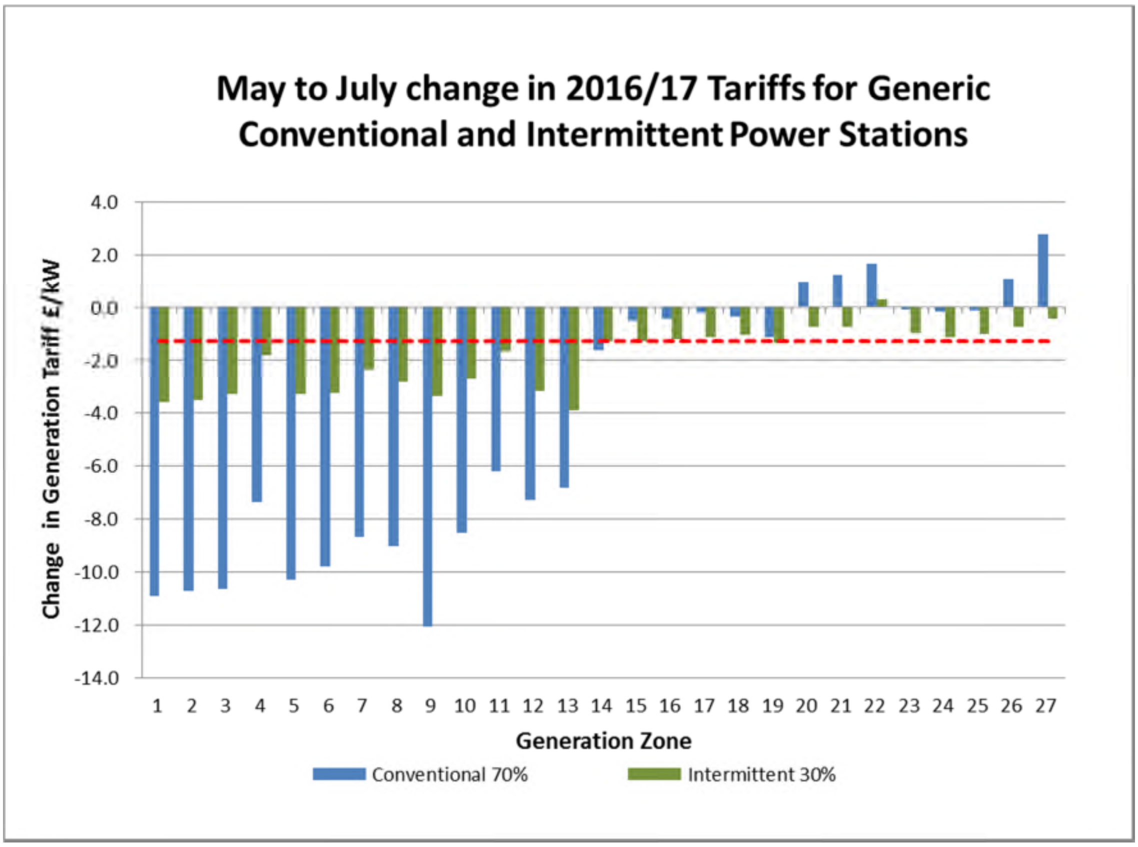
5.1 Wider zonal generation tariffs

Table 12 and Figure 2 show the changes in generation Wider TNUoS tariffs between the May forecast and this forecast for a conventional generator with 70% load factor and an intermittent generator with 30% load factor. Under the Transmit methodology each generator has its own load factor. The 70% and 30% load factors used here are only for illustration.

Table 12 - Variation in generation zonal tariffs

Wider Generation Tariffs (£/kW)									
		Conventional 70%			Intermittent 30%			Change in Residual (£/kW)
Zone	Zone Name	2016/17 May Forecast (£/kW)	2016/17 July Forecast (£/kW)	Change (£/kW)	2016/17 May Forecast (£/kW)	2016/17 July Forecast (£/kW)	Change (£/kW)	
1	North Scotland	22.22	11.33	-10.89	13.52	9.95	-3.57	-1.29
2	East Aberdeenshire	18.76	8.06	-10.70	11.59	8.08	-3.50	-1.29
3	Western Highlands	20.29	9.66	-10.63	12.59	9.30	-3.29	-1.29
4	Skye and Lochalsh	14.29	6.92	-7.37	12.35	10.54	-1.81	-1.29
5	Eastern Grampian and Tayside	18.61	8.33	-10.28	11.88	8.61	-3.27	-1.29
6	Central Grampian	20.33	10.56	-9.78	11.69	8.45	-3.24	-1.29
7	Argyll	21.03	12.36	-8.67	14.36	12.00	-2.36	-1.29
8	The Trossachs	16.41	7.40	-9.01	9.45	6.62	-2.82	-1.29
9	Stirlingshire and Fife	15.60	3.54	-12.06	8.75	5.41	-3.34	-1.29
10	South West Scotland	15.10	6.59	-8.50	9.10	6.39	-2.71	-1.29
11	Lothian and Borders	11.71	5.52	-6.19	5.27	3.63	-1.64	-1.29
12	Solway and Cheviot	10.12	2.84	-7.28	6.46	3.29	-3.18	-1.29
13	North East England	8.59	1.77	-6.82	4.05	0.17	-3.88	-1.29
14	North Lancs and The Lakes	7.24	5.63	-1.60	4.32	3.06	-1.26	-1.29
15	South Lancs, Yorks and Humber	6.13	5.61	-0.51	1.88	0.62	-1.26	-1.29
16	North Midlands and North Wales	4.90	4.48	-0.42	1.55	0.36	-1.19	-1.29
17	South Lincs and North Norfolk	2.94	2.77	-0.18	1.44	0.33	-1.10	-1.29
18	Mid Wales and The Midlands	2.48	2.14	-0.35	1.46	0.43	-1.03	-1.29
19	Anglesey and Snowdon	7.35	6.23	-1.12	2.12	0.79	-1.34	-1.29
20	Pembrokeshire	6.47	7.43	0.97	0.22	-0.51	-0.73	-1.29
21	South Wales	3.53	4.75	1.21	0.19	-0.53	-0.72	-1.29
22	Cotswold	-1.73	-0.07	1.66	-4.70	-4.40	0.30	-1.29
23	Central London	-5.24	-5.32	-0.08	-2.96	-3.94	-0.97	-1.29
24	Essex and Kent	-1.00	-1.14	-0.14	2.25	1.15	-1.10	-1.29
25	Oxfordshire, Surrey and Sussex	-1.73	-1.83	-0.10	0.79	-0.20	-0.99	-1.29
26	Somerset and Wessex	-3.70	-2.64	1.06	0.20	-0.53	-0.73	-1.29
27	West Devon and Cornwall	-5.06	-2.28	2.78	-0.50	-0.92	-0.42	-1.29

Figure 2 - Variation in Generation Zonal Tariffs



Locational Tariff

Whilst our best view of the generation charging base has seen a significant reduction in generation, by far the most significant impact on the locational tariff is as a result of reducing the TEC of Longannet power station in zone 9 to zero. This decreases the tariffs in the north (zones 1 to 13). Since the peak scenario has no intermittent generation the impact of Longannet is greater for conventional plant, reflecting the need for peak plant in Scotland.

The increase in Wales (zones 20 to 22) and Cornwall (zones 26 and 27) is due to increased west to east flows.

Residual Tariff

The residual element of the tariff has reduced by £1.29/kWh. This is predominantly due to the reduction in revenue recovered from generation due to the cap on average annual generator charges.

5.2 Onshore local circuit tariffs

Onshore local circuit tariffs have been updated from the May forecast. Variations from the May forecast are generally caused by changes in flow on surrounding circuits.

5.3 Onshore local substation tariffs

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

6 Forecast demand tariffs for 2016/17

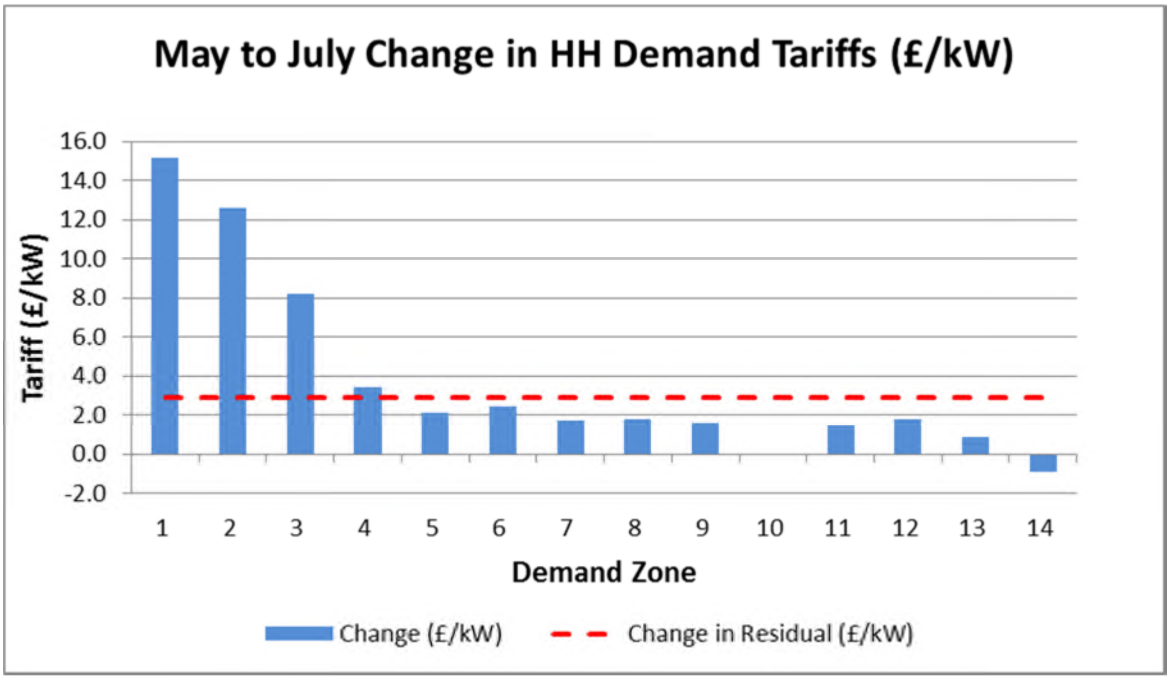
6.1 Half Hour Demand Tariffs

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

Table 13 - Change in HH Demand Tariffs

Zone	Zone Name	2016/17 May Forecast (£/kW)	2016/17 July Forecast (£/kW)	Change (£/kW)	Change in Residual (£/kW)
1	Northern Scotland	29.34	44.51	15.17	2.88
2	Southern Scotland	31.40	43.99	12.59	2.88
3	Northern	37.38	45.58	8.20	2.88
4	North West	40.92	44.31	3.39	2.88
5	Yorkshire	41.67	43.80	2.13	2.88
6	N Wales & Mersey	41.28	43.73	2.45	2.88
7	East Midlands	44.85	46.57	1.72	2.88
8	Midlands	45.62	47.41	1.79	2.88
9	Eastern	46.97	48.54	1.56	2.88
10	South Wales	44.09	44.03	-0.06	2.88
11	South East	49.65	51.12	1.46	2.88
12	London	51.95	53.75	1.80	2.88
13	Southern	51.00	51.87	0.86	2.88
14	South Western	51.30	50.38	-0.93	2.88

Figure 3 - Change in HH Demand Tariffs



Locational Tariff

The most significant impact on the locational element of the demand tariffs is the reduction in TEC of Longannet Power Station to zero. This increases the tariffs in the North (zones 1 to 3) with corresponding reductions in the south.

Residual Tariff

The residual tariff element of HH demand tariffs has increased by £2.88/kW since the May forecast. £1.79/kW of this increase is attributable to the increase in revenue recovered from Suppliers as a result of the cap on average annual generator charges with the remaining increase mainly due to lower forecast demand at Triad. The weighted average HH tariff increases by £2.86/kW. However, the removal of the P272 adjustment results in a smaller charging base so despite the increase in average HH tariffs the revenue recovered from HH demand reduces by £102m.

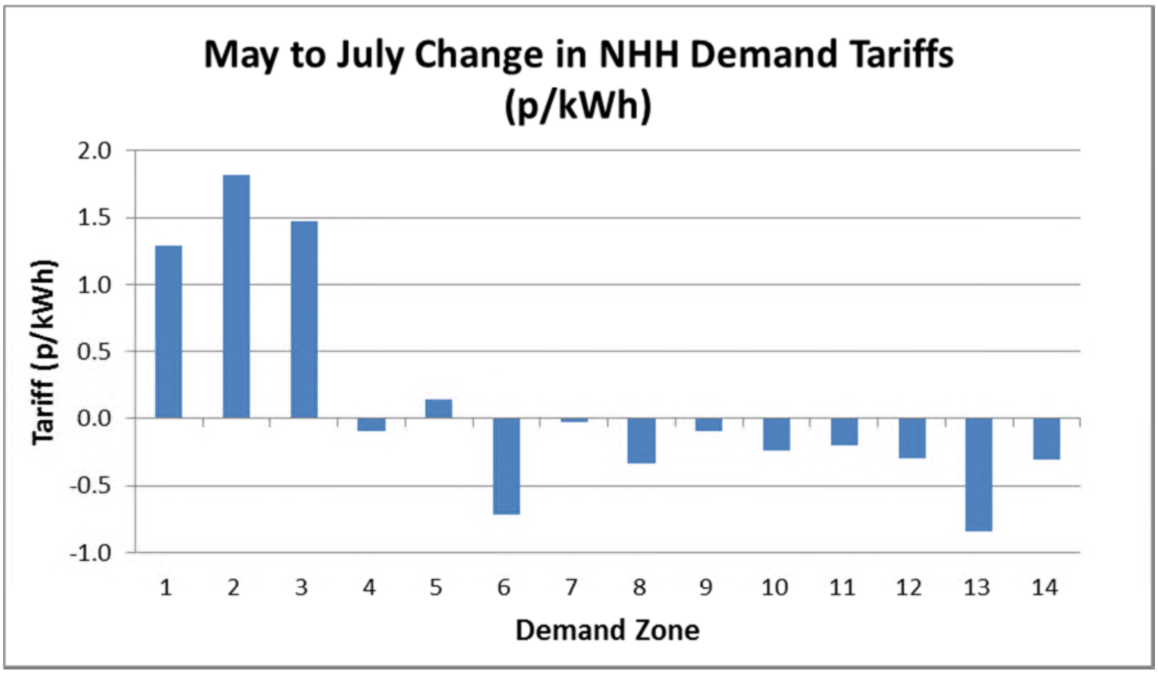
6.2 Non Half-hourly demand tariffs

Table 14 and Figure 4 show the difference between the Non-Half-Hourly (NHH) demand tariffs forecast in May and this forecast.

Table 14 - NHH Demand Tariff Changes

Zone	Zone Name	2016/17 May Forecast (p/kWh)	2016/17 July Forecast (p/kWh)	Change (p/kWh)
1	Northern Scotland	4.34	5.63	1.29
2	Southern Scotland	4.57	6.39	1.81
3	Northern	5.05	6.52	1.47
4	North West	5.77	5.67	-0.09
5	Yorkshire	6.10	6.24	0.14
6	N Wales & Mersey	6.79	6.07	-0.72
7	East Midlands	6.23	6.20	-0.02
8	Midlands	6.53	6.20	-0.33
9	Eastern	6.45	6.35	-0.10
10	South Wales	6.37	6.13	-0.24
11	South East	6.72	6.52	-0.20
12	London	7.12	6.83	-0.29
13	Southern	7.16	6.31	-0.85
14	South Western	6.92	6.61	-0.31

Figure 4 - NHH Tariff Demand Changes



The changes in NHH tariffs since the May forecast follow a broadly similar pattern to the change in HH tariffs. For example tariffs in zones 1 to 3 increase due to the reduction in TEC at Longannet Power Station to zero.

However, there are additional changes due to local variations in forecast demand at peak and the HH and NHH chargeable demand (See Appendix C.) For example in North Wales & Mersey (Zone 6) and Southern (Zone 13) the forecast peak demand has been reduced which reduces the proportion of revenue to be recovered from HH and NHH chargeable demand in those zones. However, the forecast HH chargeable demand in those zones has increased. This further reduces the revenue to be obtained from NHH chargeable demand in those zones. The NHH chargeable demand is unchanged in zone 6 and higher in zone 13 so the NHH tariffs in these zones reduce due to the lower revenue requirement.

The weighted average NHH tariff has increased by 0.01p/kW. However, the removal of the P272 adjustment increases the NHH charging base so revenue recovered from NHH demand will increase by £182m despite the negligible change in average tariffs.

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)	0.0
Change in HH Demand Tariffs (£/kW)	1.01
Change in NHH Demand Tariffs (p/kWh)	0.13

7.2 Demand charging base

An increase in the demand charging base decreases tariffs. Table 16 shows the impacts of a 1% increase in system demand and corresponding decreases in HH and NHH chargeable demand.

Table 16 - Impact of 1% decrease in demand

Change in Demand		Change in Tariff	
Peak Demand (MW)	493		
HH Demand (MW)	142	HH Tariff (£/kW)	-0.47
NHH Demand (TWh)	0.27	NHH Tariff (£/kWh)	-0.06

7.3 Generation charging base

The tariffs presented in this document are based upon the contracted generation background for 2016/17 as of 6 June 2015. The locational element of tariffs is expected to be fixed 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.

7.4 Circuit parameters

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

7.5 Longannet

This forecast assumes that Scottish Power will notify the closure of Longannet prior to the fixing of the contracted generation background on 31 October 2015. Appendix D shows the impact on tariffs if it is not notified before 31 October 2015.

8 Tools and Supporting Information

8.1 Further information

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

Team phone		01926 654633
Stuart Boyle	stuart.boyle@nationalgrid.com	01926 655588

8.2 Charging forums

We will be hosting a webinar on Thursday 30 July 2015 at 1pm 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: TNUoS tariffs including Longannet

Appendix E: Generation Zones

Appendix F: Demand Zones

Appendix A : Revenue Tables

These pages provide more detail on the price control forecasts for National Grid, Scottish Power Transmission and SHE Transmission. Revenue for offshore networks is also included with forecasts by National Grid where 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 17 - National Grid Revenue Forecast

National Grid Revenue Forecast				Updated:	03/07/2015			
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%	1.13%	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	-19.9	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3A	ALL	3.1%	2.5%	1.1%	HM Treasury Forecast then 2.8%
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	3.1%	2.4%	2.4%	HM Treasury Forecast then 2.8%
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	3.0%	3.2%	3.0%	HM Treasury Forecast then 2.8%
RPI Forecast	A4	RPIFt	3A	ALL	1.2051	1.2267	1.2380	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1732.7**	**1675.5**	**1796.9**	
Pass-Through Business Rates	B1	RBt	3B	ALL		1.2	1.5	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL	0.1	0.0	0.1	Licensee Actual/Forecast
Licence Fee	B3	LFt	3B	NG		2.0	2.7	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	3B	NG		3.8	2.7	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	293.4	14/15 & 15/16 Charge setting. Later from TSP Calculation.
SHE Transmission Pass-Through	B7	TSHt	3B	NG	214.0	338.2	325.5	14/15 & 15/16 Charge setting. Later from TSH Calculation.
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	218.4	248.4	259.3	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**	**885.9**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL		2.4	3.9	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL		8.7	9.7	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL		2.8	2.7	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**	**16.4**	
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	104.1	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**		**ALL**	**2524.3**	**2681.6**	**2857.6**	
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**	**2812.6**	
Forecast percentage change to Maximum Revenue M				**NG**	**0.0%**	**6.2%**	**6.6%**	
Forecast percentage change to TNUoS Collected Revenue T				**NG**	**0.0%**	**6.4%**	**6.7%**	

Table 18 - 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%	0.70%	1.50%	0.00%
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	1.2380	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**292.9**	**293.4**	**273.4**	
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**	**302.3**	
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**	**293.4**	**General System Charge**
Forecast percentage change to TNUoS Collected Revenue T				**ALL**	**0.0%**	**-5.3%**	**-0.8%**	

Table 19 - SHE Transmission Revenue Forecast

SHE Transmission Revenue Forecast				Updated:	03/07/2015			
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%	0
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	85.2	89.0	Forecast of cummulativce MOD impacts, excl non approved
RPI True Up	A3	TRUt	3A	ALL	-0.0	0.5	-2.6	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.2051	1.2267	1.2380	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**144.8**	**257.4**	**260.0**	
Pass-Through Business Rates	B1	RBt	3B	ALL	0.0	-0.7	-16.1	RBt rebate received in 2014/15, pass through in 2016/17
Temporary Physical Disconnection	B2	TPDt	3B	ALL	0.0	0.6	0.1	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**-0.1**	**-16.0**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL		1.2	0.2	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL		1.6	2.0	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**	**2.2**	
Network Innovation Allowance	D	NIAt	3H	ALL	1.3	1.7	1.7	Licensee Actual/Forecast
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	72.2	81.2	80.2	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		-1.7	0.8	Latest Forecast
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**218.2**	**341.6**	**329.0**	
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**	**214.8**	**338.1**	**325.5**	General System Charge
Forecast percentage change to TNUoS Collected Revenue T				**ALL**	**0.0%**	**57.4%**	**-3.7%**	

Table 20 - Offshore Transmission Owner Revenues

<table>
<tr><th colspan="1">Offshore Transmission Revenue Forecast</th><th colspan="3">29/05/2015</th><th rowspan="3">Notes</th></tr>
<tr><th>Description</th><th>Yr t-1</th><th>Yr t</th><th>Yr t+1</th></tr>
<tr><th>Regulatory Year</th><th>2014/15</th><th>2015/16</th><th>2016/17</th></tr>
<tr><td>Barrow</td><td>5.5</td><td>5.6</td><td>5.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gunfleet</td><td>6.9</td><td>7.0</td><td>7.1</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 1</td><td>12.5</td><td>12.8</td><td>12.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>Robin Rigg</td><td>7.7</td><td>7.9</td><td>8.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Walney 2</td><td>12.9</td><td>13.2</td><td>13.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Sheringham Shoal</td><td>18.9</td><td>19.5</td><td>19.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Ormonde</td><td>11.6</td><td>11.8</td><td>12.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Greater Gabbard</td><td>26.0</td><td>26.6</td><td>26.9</td><td>Current revenues plus indexation</td></tr>
<tr><td>London Array</td><td>37.6</td><td>39.2</td><td>38.0</td><td>Current revenues plus indexation</td></tr>
<tr><td>Thanet</td><td rowspan="4">78.9</td><td>17.5</td><td>17.7</td><td>Current revenues plus indexation</td></tr>
<tr><td>Lincs</td><td>25.6</td><td>25.4</td><td>Current revenues plus indexation</td></tr>
<tr><td>Gwynt y mor</td><td>26.3</td><td>25.6</td><td>Current revenues plus indexation</td></tr>
<tr><td>West of Duddon Sands</td><td rowspan="3">35.3</td><td rowspan="3">46.8</td><td>National Grid Forecast</td></tr>
<tr><td>Humber Gateway</td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Westermost Rough</td><td></td><td>National Grid Forecast</td></tr>
<tr><td>Offshore Transmission Pass-Through (B7)</td><td>218.4</td><td>248.4</td><td>259.3</td><td></td></tr>
</table>

Appendix B : Generation changes for 2016/17

Table 21 shows TEC changes notified between April 2015 (used for the May forecast) and June 2015 (used for this forecast.) This tariffs in this forecast are based on National Grid's best view and therefore include additional changes to those shown below, e.g. the forecast closure of Longannet.

Table 21 - Generation TEC Changes

Station	Agreement Type	Node	Zone	TEC Register 13/04/15	TEC Register 04/06/2015	MW Change
Cour Wind Farm	BCA	CRSS10	7	23	21	-3
Freasdail	BCA	CRSS10	7	0	28	28
Littlebrook	BCA	LITT40	24	800	0	-800
Marchwood	BCA	MAWO40	26	900	920	20
Strathy North and South Wind	BCA	STRW12	1	226	200	-26
Glenchamber Wind Farm	BEGA	GLLU1Q	10	0	25	25
Moy Wind Farm	BEGA	INVE10	7	0	60	60
Total				1,949	1,254	-695

Appendix C : Locational Demand changes

Table 22 - Demand Profiles

Zone	Zone Name	May Forecast				July Forecast			
		Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW Pre-P272)	Tariff model NHH Demand (TWh Pre-P272	Locational Model Demand (MW)	Tariff model Peak Demand (MW)	Tariff Model HH Demand (MW)	Tariff model NHH Demand (TWh)
1	Northern Scotland	848	1,093	- 89	0.80	642	976	25	0.75
2	Southern Scotland	3,337	3,573	951	1.79	3,286	3,420	839	1.78
3	Northern	2,636	2,285	457	1.34	2,636	2,158	220	1.35
4	North West	4,009	4,093	1,140	2.08	4,009	4,027	1,344	2.10
5	Yorkshire	4,582	3,939	1,133	1.91	4,582	3,781	997	1.95
6	N Wales & Mersey	2,092	2,770	583	1.34	2,092	2,574	722	1.34
7	East Midlands	4,966	4,696	1,480	2.30	4,966	4,586	1,472	2.34
8	Midlands	4,414	4,292	1,169	2.17	4,414	4,235	1,345	2.21
9	Eastern	5,583	6,079	1,469	3.32	5,583	6,011	1,545	3.42
10	South Wales	1,920	1,814	522	0.89	1,920	1,758	489	0.91
11	South East	3,609	3,638	811	2.06	3,609	3,482	790	2.11
12	London	4,661	4,725	1,967	1.99	4,661	4,690	2,093	2.04
13	Southern	5,995	5,443	1,517	2.78	5,995	5,293	1,812	2.86
14	South Western	2,518	2,392	497	1.39	2,518	2,332	498	1.40
Total		51,171	50,832	13,608	26.16	50,913	49,323	14,188	26.56

Appendix D : TNUoS tariffs including Longannet

The following tables show the effect of Longannet retaining contracted TEC on 31 October 2015.

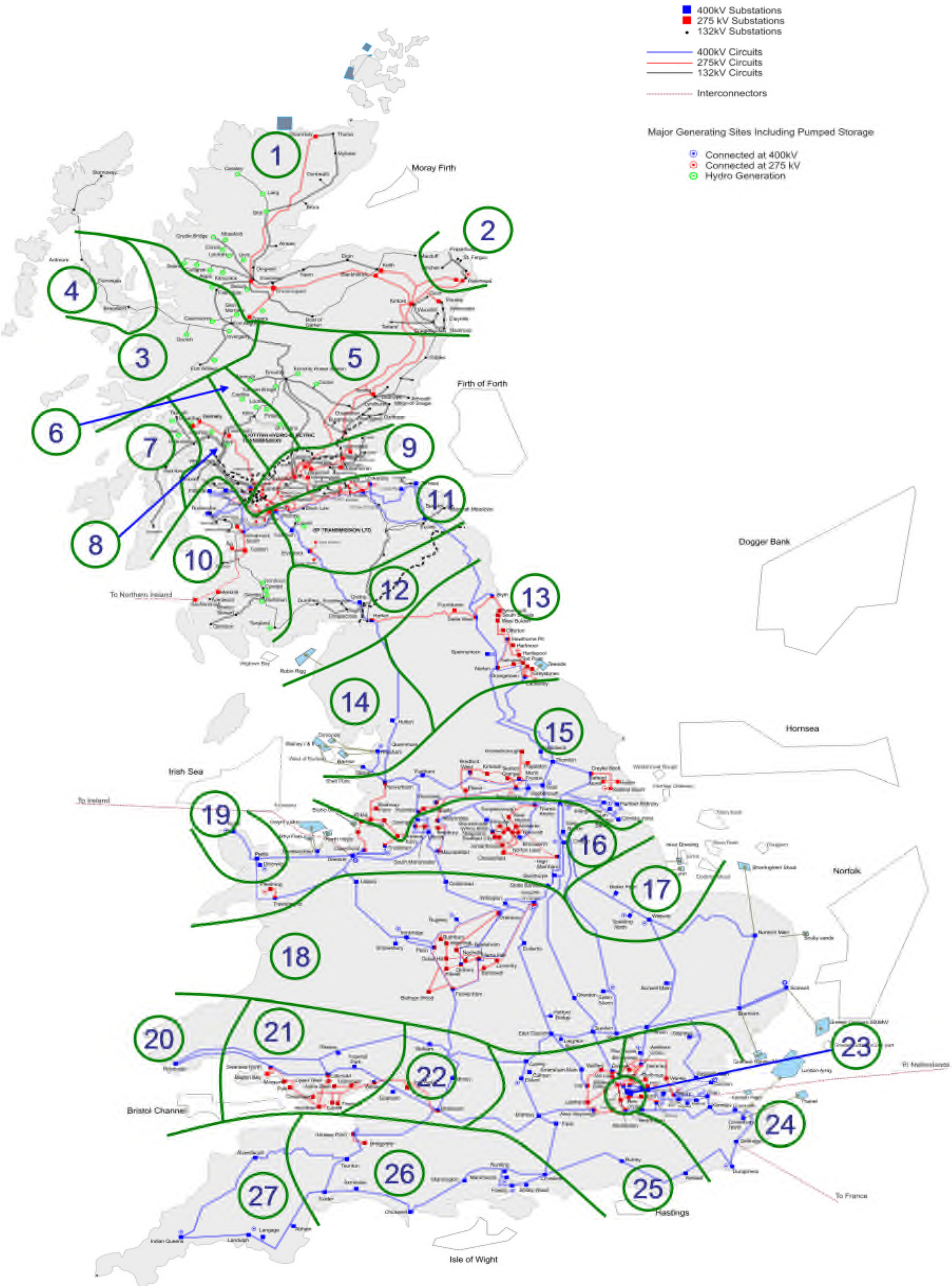
Table 23 : Wider Generation Tariff

		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	4.34	14.94	6.27	0.44	21.51	11.19
2	East Aberdeenshire	5.44	8.79	6.27	0.44	18.30	9.35
3	Western Highlands	4.16	12.76	6.27	0.44	19.80	10.54
4	Skye and Lochalsh	0.18	12.76	7.50	0.44	17.06	11.77
5	Eastern Grampian and Tayside	3.89	11.41	5.97	0.44	18.30	9.84
6	Central Grampian	5.67	11.06	5.81	0.44	19.68	9.58
7	Argyll	5.15	8.65	10.02	0.44	21.67	13.06
8	The Trossachs	4.73	8.65	4.62	0.44	15.85	7.66
9	Stirlingshire and Fife	4.73	7.53	4.37	0.44	14.82	7.08
10	South West Scotlands	3.51	8.66	4.37	0.44	14.39	7.41
11	Lothian and Borders	3.54	8.66	0.30	0.44	10.35	3.34
12	Solway and Cheviot	2.37	5.03	3.09	0.44	9.43	5.05
13	North East England	4.23	2.34	1.50	0.44	7.82	2.65
14	North Lancashire and The Lakes	2.37	2.34	1.94	0.44	6.39	3.08
15	South Lancashire, Yorkshire and Humber	4.48	0.40		0.44	5.20	0.57
16	North Midlands and North Wales	3.14	0.16		0.44	3.70	0.49
17	South Lincolnshire and North Norfolk	1.15	0.02	0.00	0.44	1.61	0.45
18	Mid Wales and The Midlands	0.52	0.37		0.44	1.22	0.56
19	Anglesey and Snowdon	4.62	1.53		0.44	6.14	0.90
20	Pembrokeshire	7.48	-3.29		0.44	5.62	-0.54
21	South Wales & Gloucester	4.88	-3.32		0.44	3.00	-0.55
22	Cotswold	1.73	2.67	-5.90	0.44	-1.86	-4.65
23	Central London	-3.75	2.67	-5.10	0.44	-6.54	-3.85
24	Essex and Kent	-4.67	2.67		0.44	-2.35	1.25
25	Oxfordshire, Surrey and Sussex	-2.20	-1.91		0.44	-3.10	-0.13
26	Somerset and Wessex	-2.36	-3.14		0.44	-4.11	-0.50
27	West Devon and Cornwall	-1.92	-5.31		0.44	-5.19	-1.15

Table 24 : Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	32.96	4.17
2	Southern Scotland	34.06	4.94
3	Northern	40.22	5.76
4	North West	43.92	5.62
5	Yorkshire	44.75	6.38
6	N Wales & Mersey	44.26	6.14
7	East Midlands	47.78	6.36
8	Midlands	48.43	6.33
9	Eastern	50.18	6.56
10	South Wales	46.40	6.46
11	South East	52.85	6.75
12	London	55.43	7.04
13	Southern	53.64	6.53
14	South Western	53.05	6.96

Appendix E : Generation Zones



Appendix F : Demand Zones