Tariff Information Paper

July 2014 forecast of TNUoS tariffs for 2015/16

This information paper provides National Grid's July view of Transmission Network Use of System (TNUoS) tariffs for 2015/16, which apply to generators and suppliers.

July 31st 2014 V1.0

August 5th 2014 V1.1 Update tariffs in table 14 to match tariffs in table 5 (maximum change 0.01)

Contents

Any Questions?

Contact:

Damian.Clough@nationalgrid.com

mary.owen@nationalgrid.com

Damian 01926 656416

Mary 01926 653845

1 Executive Summary

This forecast discusses our latest view of Transmission Network Use of System (TNUoS) tariffs for 2015/16 and explains any changes from the previous forecast published in May 2014

CUSC Modification Proposal CMP213 ('Project Transmit') will be implemented in April 2016*. Previous forecasts of 2015/16 tariffs had this methodology change as a scenario for 2015/16. The implementation date of April 2016 means that Transmit will not impact 2015/16 tariffs.

Forecast total transmission revenue has reduced from £2,645m to £2,612m using information from the annual regulatory reporting process. However, forecast Generation tariffs have increased slightly compared to the last update, due to a reduction in the generation charging base as schemes delay their connection dates. The schemes which have delayed are spread geographically so there has been little impact on the locational element of the tariff.

The peak demand forecast for 2015/16 has been reduced from 55.3GW to 54.2GW. This reduction means that, although allowed revenue has reduced against previous forecasts, this is offset leading to a rise in the Half Hourly residual (the same for all zones) of £0.42 p/kW. In Scotland less generation sees Half Hourly (HH) tariffs increase on top of the residual. This is balanced by England and Wales which see changes below the residual. As well as reducing the forecast of Peak demand, the zonal distribution of demand has been updated leading to regional variations in Non Half Hourly tariffs.

The main uncertainty affecting forecast tariffs revolves around EU Regulation ECR 838/2010. This regulation limits average annual generation use of system charges to €2.5/MWh which is forecast to be breached in 2015/16. CUSC Modification Proposal CMP224 will enable the charging methodology to comply with the EU directive by changing the proportions of revenue recovered from generation and demand.

ACER (the Agency for the Cooperation of European Regulators) carried out a review of the appropriateness of the €2.5/MWh limit for the period beyond December 2014. Their opinion is that this limit should only apply to energy based charges and therefore Generation TNUoS tariffs, which are capacity based, would be exempt. However, it is not known if the European Commission will choose to make changes in line with ACER's opinion, make other changes it deems appropriate, or maintain the current limit before tariffs are fixed in January.

This forecast calculates tariffs using the current 27:73 split. Tariffs based on an adjusted Generation and Demand split have also been included.

* http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=34632

2 Introduction

2.1 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, we determine a locational component of TNUoS tariffs using a model of power flows on the transmission system. This model considers the impact that increases in generation or demand have on power flows at times of peak demand. 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 transmission system.

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 or in the correct ratios (Generation:Demand split). 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 in the defined proportions (Generation = 27%, Demand = 73%)

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.

As the year progresses, the data which feeds into the model above is updated to reflect our best view on how the data will look when tariffs are fixed. There is an element of uncertainty in these forecasts which reduces as we get closer to finalising the tariffs. Scenarios are provided in some cases to show the impact of the uncertainty.

2.2 Structure of Document

Section 3 contains a forecast of all tariffs for charging year 2015/16.

Section 4 discusses changes to data since the last update and the rationale behind those changes.

Section 5 explains how the changes detailed in section 4 have altered Generation tariffs.

Section 6 explains how the changes detailed in section 4 have altered Demand tariffs.

Section 7 discusses how the data may change before tariffs are fixed in January 2015 and the likely effect on tariffs of those changes.

Sections 8 and 9 gives details on how you can obtain the model used to set tariffs, give feedback on this forecast and ask further questions. We do find this feedback valuable and have already put into place comments based on last year's feedback with the aim of continuously improving the forecasting process.

3 Tariff Summary

This section shows the latest forecast of generation and demand tariffs forecast for 2015/16. Information on how these tariffs were calculated and why they have changed from the five year forecast published in May can be found in later sections. Tariffs are set based on current methodology and a Generation and Demand split of 27:73.

3.1 Generation Tariffs 2015/16

Table 1

Wider Generation Tariffs (£/kW)		
Zone	**Zone Name**	**15/16**
1	North Scotland	26.98
2	East Aberdeenshire	22.61
3	Western Highlands	25.03
4	Skye and Lochalsh	30.47
5	Eastern Grampian and Tayside	23.70
6	Central Grampian	22.35
7	Argyll	22.55
8	The Trossachs	19.16
9	Stirlingshire and Fife	18.32
10	South West Scotland	17.10
11	Lothian and Borders	14.40
12	Solway and Cheviot	12.93
13	North East England	9.67
14	North Lancs and The Lakes	9.03
15	South Lancs, Yorks and Humber	7.36
16	North Midlands and North Wales	5.95
17	South Lincs and North Norfolk	4.12
18	Mid Wales and The Midlands	3.17
19	Anglesey and Snowdon	8.43
20	Pembrokeshire	6.32
21	South Wales	3.74
22	Cotswold	0.51
23	Central London	-4.06
24	Essex and Kent	0.36
25	Oxfordshire, Surrey and Sussex	-1.28
26	Somerset and Wessex	-3.31
27	West Devon and Cornwall	-5.30

Small Generators Discount (£/kW) = 9.51

Local Substation Tariffs (£/kW)

Table 2

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.180243	0.103110	0.074292
<1320 MW	Redundancy	0.397060	0.245662	0.178667
>=1320 MW	No redundancy	-	0.323296	0.233809
>=1320 MW	Redundancy	-	0.530768	0.387418

Local Circuit Tariffs (£/kW)

Table 3

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.40	Dersalloch	1.64	Killgallioch	1.32
Afton	3.65	Didcot	0.22	Killingholme	0.37
Aigas	0.59	Dinorwig	2.16	Kilmorack	0.18
An Suidhe	1.80	Dumnaglass	1.73	Langage	0.59
Arecleoch	0.28	Dunlaw Extension	1.26	Lochay	0.33
Baglan Bay	0.64	Edinbane	6.15	Luichart	1.02
Black Law	0.90	Fallago	0.07	Marchwood	0.34
Blacklaw Extension	2.16	Farr Windfarm	1.99	Mark Hill	-0.79
Bodelwyddan	0.10	Ffestiniogg	0.23	Millennium Wind	1.46
Brochloch	3.36	Finlarig	0.29	Mossford	3.56
Carraig Gheal	3.95	Foyers	0.69	Nant	-1.10
Clyde (North)	0.10	Glendoe	1.65	Neilston	0.79
Clyde (South)	0.11	Glenmoriston	1.19	Rocksavage	0.02
Corriegarth	2.28	Gordonbush	2.35	Saltend	0.31
Corriemoillie	2.47	Griffin Wind	1.67	South Humber Bank	0.83
Coryton	0.32	Hadyard Hill	2.47	Spalding	0.27
Cour	0.41	Harestanes	4.78	Strathy Wind	3.54
Cruachan	1.71	Hartlepool	0.54	Whitelee	0.10
Crystal Rig	-0.01	Hedon	0.16	Whitelee Extension	0.26
Culligran	1.56	Invergarry	1.27		
Deanie	2.56	Kilbraur	2.10		

Offshore Local Tariffs (£/kW)

Table 4

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.42	27.55	8.54
Robin Rigg West	-0.42	27.55	8.54
Gunfleet Sands 1 & 2	15.74	14.45	2.70
Barrow	7.27	38.04	0.94
Ormonde	22.48	41.88	0.33
Walney 1	19.40	38.64	
Walney 2	19.26	38.98	
Sheringham Shoal	21.72	25.47	0.55
Greater Gabbard	13.63	31.33	
London Array	9.25	31.51	

3.2 Demand Tariffs 2015/16

Half Hour metered zonal tariffs (£/kW) and Non-Half Hour metered zonal tariffs (p/kWh)

Table 5

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	19.60	2.96
2	Southern Scotland	22.84	3.26
3	Northern	29.11	3.63
4	North West	32.05	4.51
5	Yorkshire	32.72	4.43
6	N Wales & Mersey	32.07	5.07
7	East Midlands	35.52	4.77
8	Midlands	36.25	5.04
9	Eastern	37.44	5.01
10	South Wales	34.72	4.65
11	South East	40.18	5.37
12	London	42.58	5.54
13	Southern	41.36	5.58
14	South Western	41.04	5.33

4 Updates to the Charging Model for 2015/16

Since the five year forecast of tariffs published in May, updates have been made to the contracted generation background, generation charging base, total revenue and the demand charging base. No changes have been made to circuit data or DNO demand data.

4.1 Changes influencing the locational element of tariffs

4.1.1 Generation

In previous publications, Generation data used to create the transport model was based upon contracted TEC. Contracted Generation significantly affects tariff forecasts and it is recognised that contracted TEC was not always a good representation due to station closures, project delays and terminations. The Generation data used within this forecast is our best view based upon contracted TEC (from the TEC register) and market intelligence. We have taken a view as to the likelihood of a number of new Generation projects progressing as planned. Where progression looked likely to vary from plan we have adjusted the contracted TEC to reflect how we view the project is likely to progress.

The overall result of these adjustments is that our 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. Table 6 shows the total Generation TEC that has been included in the charging model from 2014/15 to 2015/16 and the contracted Generation for that year.

Table 6 - Contracted and Modelled TEC (GW)

	2014/15	2015/16 May forecast	2015/16 July forecast
Contracted TEC	77.2	80.3	78.8
Modelled TEC	77.2	79.5	77.9

The locational element of tariffs will be fixed using the contracted background on 31 October 2014.

4.1.2 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 unchanged from that used in the May forecast and this will not change before charges are finalised in January 2015. However, embedded generation and directly connected demand forecasts may be updated further throughout the year. This has been updated since May resulting in overall forecast demand increasing slightly due to a reduction in contracted embedded generation for 2015/16 (embedded generation reduces DNO demand).

4.2 Changes influencing the residual element of tariffs

4.2.1 Allowed Revenues

We are responsible for collecting revenues on behalf of all onshore and offshore Transmission Owners (TO) in Great Britain. The revenues of onshore TOs are subject to price controls set by Ofgem at periodic price reviews. The current price control period runs from 2013/14 to 2020/21.

During this price control period each TO's allowed revenue can be adjusted by Ofgem depending on its performance and the volume of connections and capacity delivered. Connections and capacity are driven by customer applications. These adjustments generally lag by two years, i.e. TOs report their 2013/14 performance by the end of July 2014, following which Ofgem will determine adjustments to 2015/16 base allowed revenue around the end of November 2014. This document has used a snapshot of the information being prepared to report to Ofgem to forecast Ofgem's adjustments and therefore the allowed revenue of onshore TOs during 2015/16. Please note that these are only forecasts as the information submitted to Ofgem may differ and the actual allowance adjustments won't be known until Ofgem makes its determinations in the autumn.

As well as determining adjustments to base allowed revenue, Ofgem will also be determining the awards to TOs shown in Table 7, later this year.

Table 7

	Included in forecast £m	Maximum £m
Environmental Discretionary Rewards	0.0	4.0
Stakeholder Engagement Awards	0.0	10.2
Network Innovation Competition Funding[†]	16.7	33.3
Total	16.7	47.5

Onshore TOs may also receive revenue for Transmission Investment for Renewable Generation (TIRG) and/or Strategic Wider Works (SWW). This project specific revenue is determined by Ofgem and occasionally adjusted as projects incur unexpected costs or savings. Where determinations have been made these have been included in the forecast revenue.

The revenues of offshore transmission owners (OFTOs) are determined by Ofgem in a competitive tender process. The revenue is confirmed when the network is transferred from the developer to the appointed OFTO. Prior to this there is uncertainty as to the value of the

[†]Only Transmission Network Innovation Competition Funding is shown here. Ofgem has indicated that up to £60m for the Distribution Network Innovation Competition may be collected through Transmission charges from 2015/16. However, National Grid's licence does not currently permit this and funding may also be awarded through the Low Carbon Networks fund.

revenue and when it will start. Therefore, whilst the revenues for existing OFTOs are relatively predictable, the revenue for new OFTOs is National Grid's best view.

Table 8 shows the combined forecast of 2015/16 revenues from which the tariffs in this document have been calculated. The revenue used to set tariffs for 2014/15 and previous quarterly forecasts of 2015/16 revenue are shown for comparison. Further breakdowns of these revenues can be found in Appendix B.

Table 8

£m Nominal	2014/15 TNUoS Revenue	2015/16 TNUoS Revenue		
	Jan 2014 Final	Jan 2014 Initial View	May 2014 Update	July 2014 Update
National Grid				
Price controlled revenue	*1,761.9*	*1,855.6*	*1,851.6*	*1,805.9*
Less income from connections	*47.0*	*47.0*	*47.0*	*47.0*
Income from TNUoS	**1,714.9**	**1,808.7**	**1,804.6**	**1,759.0**
Scottish Power Transmission				
Price controlled revenue	*323.0*	*342.3*	*341.6*	*344.7*
Less income from connections	*10.8*	*9.8*	*9.8*	*11.5*
Income from TNUoS	**312.2**	**332.5**	**331.8**	**333.2**
SHE Transmission				
Price controlled revenue	*217.4*	*219.3*	*218.7*	*229.7*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.6*
Income from TNUoS	**214.0**	**215.7**	**215.2**	**226.2**
Offshore	**218.4**	**276.4**	**276.4**	**277.3**
Network Innovation Competition	**17.8**	**16.7**	**16.6**	**16.7**
Total to Collect from TNUoS	**2,477.3**	**2,650.0**	**2,644.7**	**2,612.3**

4.2.2 Charging bases for 2015/16

Generation

The generation base for 2015/16 takes generation from the transport model less;

- Interconnectors;
- An adjustment to take into account that generation in negative zones do not always generate up to TEC;
- 1% to reflect likely alterations to contracted generation after 31 October.

Demand

The demand base and the split between Half-Hourly metered and Non-Half-Hourly metered demand has been changed since the May five year forecast of charges.

Peak Demand

Table 9 shows latest settlement metering demand for the peak half hours ('Triads') over the last five charging years and average Peak demand. The average is shown graphically in Figure 1. This data, used in conjunction with future energy forecasts, supports the need to reduce the forecast average Triad demand from 55.3GW to 54.2GW. This change reflects the recent trend of reduced demand, increased embedded generation, as well as demand side response and Triad avoidance. Please bear in mind the data below has not been weather corrected.

Table 9 Peak Demand per Triad leg (GW)

	Triad Leg 1			Triad Leg 2			Triad Leg 3			
Financial Year	Date	Time (HH Ending)	Demand (GW)	Date	Time (HH Ending)	Demand (GW)	Date	Time (HH Ending)	Demand (GW)	Average Demand (GW)
2013/14	25/11/2013	17:30	50.7	06/12/2013	17:30	49.9	30/01/2014	17:30	49.9	50.2
2012/13	12/12/2012	17:30	55.4	16/01/2013	17:30	54.8	29/11/2012	17:30	52.4	54.2
2011/12	02/02/2012	18:00	54.5	16/01/2012	17:30	53.4	15/12/2011	17:30	52.5	53.5
2010/11	07/12/2010	17:30	58.9	20/12/2010	17:30	58.8	06/01/2011	17:30	54.8	57.5
2009/10	07/01/2010	17:30	57.9	25/01/2010	17:30	55.3	15/12/2009	17:30	55.0	56.1

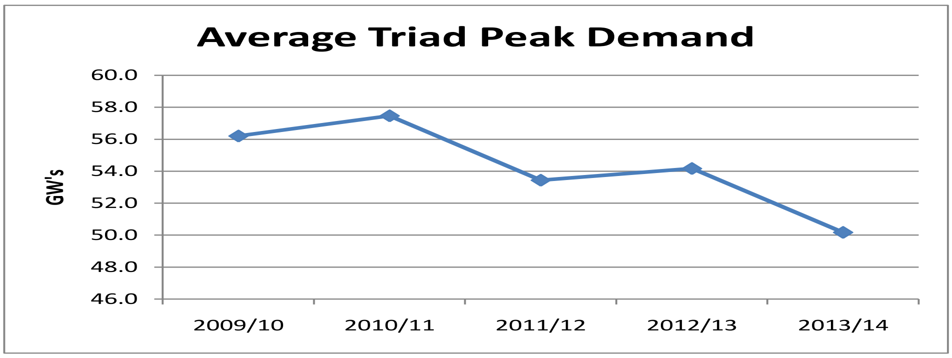

Figure 1

Demand Distribution

We have also updated the zonal distribution of peak demand. For the last three years we have maintained the same distribution of demand for each zone, with changes in peak demand distributed on a pro rata basis. Whilst this has promoted stability of demand tariffs the proportions in the model are becoming less reflective of actual demand due to differences in embedded generation, triad avoidance and closure of large demand sites. We are therefore taking this opportunity to update the zonal distribution of demand as shown in Table 10.

Table 10 - Zonal demand ratios (% of total demand)

Zone		Zonal demand ratios as proportion of total peak demand (%)		
		Old Ratios	**New Ratios**	**Change**
1	Northern Scotland	1.90%	2.15%	0.24%
2	Southern Scotland	6.77%	7.03%	0.26%
3	Northern	4.85%	4.49%	-0.36%
4	North West	8.10%	8.06%	-0.05%
5	Yorkshire	7.69%	7.75%	0.06%
6	N Wales & Mersey	4.81%	5.45%	0.64%
7	East Midlands	9.42%	9.24%	-0.19%
8	Midlands	8.42%	8.44%	0.03%
9	Eastern	12.12%	11.96%	-0.16%
10	South Wales	3.48%	3.57%	0.09%
11	South East	7.28%	7.16%	-0.12%
12	London	9.42%	9.30%	-0.13%
13	Southern	10.88%	10.71%	-0.17%
14	South Western	4.85%	4.71%	-0.14%

Non-Half Hour Metered Demand

The last five years have included both warmer and colder than average winters, providing a good view of the likely range of demand. The trend is towards lower NHH demand, due to energy efficiency and higher energy prices. The NHH demand forecast has therefore been reduced from 28.6GWh to 28.35GWh.

We do not expect to substantially change the demand charging bases between now and tariffs being set. It should be noted that actual peak demand (and the timing of the Triads in any given year) depends on a number of factors including prevailing weather and the behaviour of commercial and industrial loads.

Adjustments for Interconnectors

When determining the flows on the transmission system at peak demand, the interconnectors are included within the transport model. However, since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases. Table 11 shows Interconnectors in the transport model.

Table 11

Interconnector	Zone	Transport Model (Generation MW)
French Interconnector	24	2000
Britned	24	1200
East-West	16	500
Moyle	10	295

4.3 Other changes

4.3.1 Expansion Constant

The expansion constant has been updated from the May forecast due to a reduction in forecast RPI from 3% to 2.7%. The Expansion Constant now equals £13.249550/MWkm.

4.4 Future Forecasts/Updates

The next Quarterly Update will be published in October. Draft tariffs for 2015/16 will be published in December with Final tariffs published at the end of January 2015.

5 Forecast generation tariffs for 2015/16

The following section provides details of the forecast wider and local generation tariffs for 2015/16 using the current methodology.

5.1 Wider zonal generation tariffs

Table 12 shows the differences in generation zonal TNUoS tariffs between this and the May forecast with Figure 2 showing the same information graphically. 2014/15 tariffs are also shown for comparison purposes. An explanation of changes between years can be found in previous forecasts so is not repeated in this update.

Table 12

Wider Generation Tariffs (£/kW)				
Zone	**Zone Name**	**Tariffs 15/16**	**Change from 14/15 tariff**	**Change from May forecast**
1	North Scotland	26.98	-0.70	0.12
2	East Aberdeenshire	22.61	-0.35	0.09
3	Western Highlands	25.03	-3.32	0.01
4	Skye and Lochalsh	30.47	-3.32	0.00
5	Eastern Grampian and Tayside	23.70	-0.32	0.30
6	Central Grampian	22.35	0.38	-0.05
7	Argyll	22.55	1.70	0.21
8	The Trossachs	19.16	0.74	0.07
9	Stirlingshire and Fife	18.32	0.30	0.06
10	South West Scotland	17.10	0.64	-0.02
11	Lothian and Borders	14.40	0.22	0.08
12	Solway and Cheviot	12.93	0.20	0.14
13	North East England	9.67	-0.20	0.11
14	North Lancs and The Lakes	9.03	-0.12	0.12
15	South Lancs, Yorks and Humber	7.36	-0.25	0.14
16	North Midlands and North Wales	5.95	-0.22	0.25
17	South Lincs and North Norfolk	4.12	-0.52	0.20
18	Mid Wales and The Midlands	3.17	-0.37	0.20
19	Anglesey and Snowdon	8.43	-0.15	0.17
20	Pembrokeshire	6.32	-0.23	0.19
21	South Wales	3.74	-0.04	0.20
22	Cotswold	0.51	-0.24	0.21
23	Central London	-4.06	-0.28	0.22
24	Essex and Kent	0.36	-1.07	0.21
25	Oxfordshire, Surrey and Sussex	-1.28	-0.45	0.21
26	Somerset and Wessex	-3.31	-0.61	0.22
27	West Devon and Cornwall	-5.30	-0.60	0.22

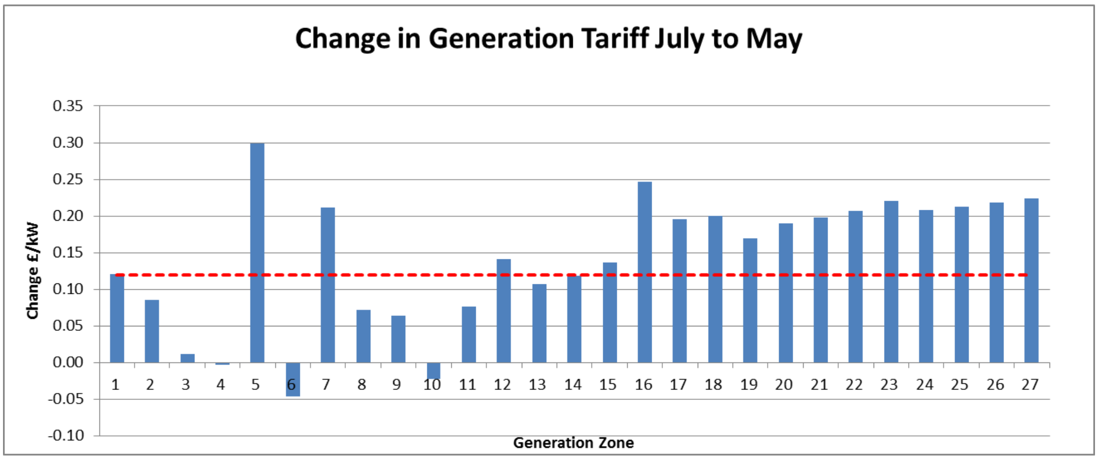

Figure 2

Residual Tariff

The Residual tariff has increased by 0.12 £/kW from 5.46 £/kW to 5.58 £/kW since the last forecast in May. This is mainly due to a decrease in the contracted generation base.

Locational Tariff

The reductions in the generation since the last forecast have been relatively evenly spread across the country. This means that the locational element to the tariffs has seen little change. The reduction in the Expansion Constant has the effect of lowering tariffs in the North and increasing tariffs in the South.

Onshore local substation tariffs

Local substation tariffs (Table 2 in Section 3) have dropped slightly from the May forecast as due to change in the forecast RPI rate used to inflate tariffs dropping from 3% to 2.7%.

5.2 Offshore local generation tariffs

The local offshore tariffs (Table 4 Section 3) have changed from the May view due to the forecast of inflation dropping from 3% to 2.7%.

5.3 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals is forecast to be £9.51/kW.

6 Forecast demand tariffs for 2015/16

6.1 HH Demand Tariffs

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

Table 13

Zone	Zone Name	Tariffs 15/16 (£/kW)	Change from 14/15 tariff (£/kW)	Change from May forecast (£/kW)
1	Northern Scotland	19.60	3.43	0.99
2	Southern Scotland	22.84	1.60	0.55
3	Northern	29.11	2.17	0.43
4	North West	32.05	2.41	0.42
5	Yorkshire	32.72	2.47	0.43
6	N Wales & Mersey	32.07	2.35	0.39
7	East Midlands	35.52	2.42	0.35
8	Midlands	36.25	2.47	0.35
9	Eastern	37.44	2.81	0.35
10	South Wales	34.72	2.40	0.36
11	South East	40.18	2.52	0.34
12	London	42.58	4.04	0.33
13	Southern	41.36	2.58	0.34
14	South Western	41.04	2.34	0.34

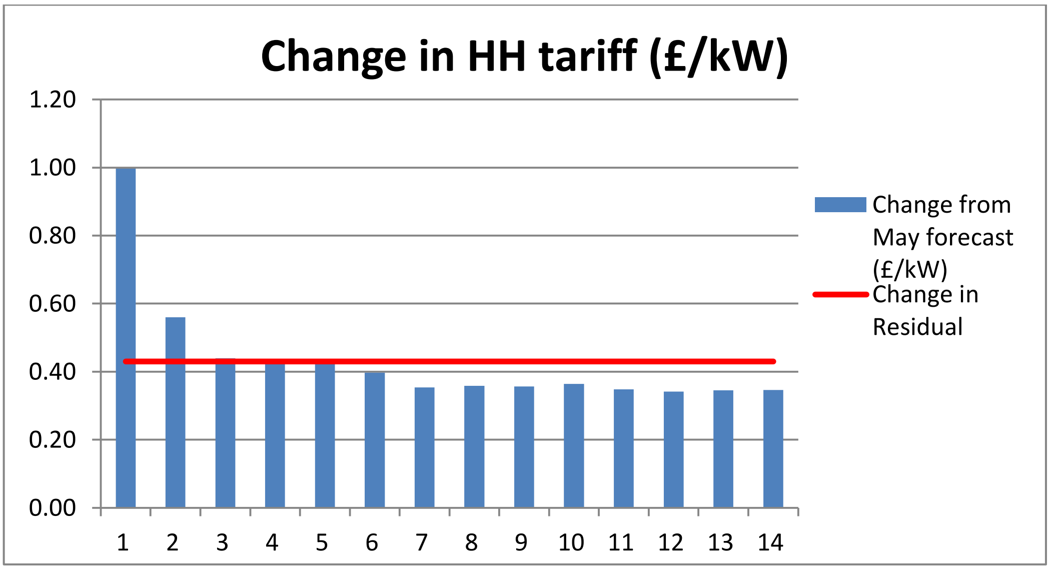

Figure 3

Residual Tariff

The residual element of HH demand tariffs, which is the same for each zone and ensures that the correct total revenue is recovered, has increased by £0.42/kW to £32.45/kW. Although the amount of revenue to be recovered from demand charges has decreased the demand charging base has also decreased as discussed in section 4.2.2.

Locational Tariff

Figure 3 shows the increase in the residual as a red line. Any change above or below this line is due to a change in the locational element of the charge. The Zone 1 tariff increase is due to a combination of reduced generation, increased demand (due to a reduction in embedded generation) and the reduction in the Expansion Constant (opposite effect to Generation).

6.2 NHH Demand Tariffs

Table 14 and Figure 4 show the difference in the Non-Half-Hourly (NHH) demand tariffs between this and the May forecasts. Similar changes to the HH demand tariffs are seen in NHH tariffs. However due to the updated information regarding zonal demand at peak, NHH tariffs do see variations over and above those seen in HH tariffs. Please see section 4.2.2 for further information.

Table 14

Zone	Zone Name	Tariffs 15/16 (p/kWh)	Change from 14/15 tariff (p/kWh)	Change from May forecast (p/kWh)
1	Northern Scotland	2.96	0.77	0.44
2	Southern Scotland	3.26	0.31	0.16
3	Northern	3.63	-0.04	-0.27
4	North West	4.51	0.27	-0.02
5	Yorkshire	4.43	0.32	0.04
6	N Wales & Mersey	5.07	0.88	0.60
7	East Midlands	4.77	0.18	-0.10
8	Midlands	5.04	0.30	0.01
9	Eastern	5.01	0.26	-0.08
10	South Wales	4.65	0.38	0.11
11	South East	5.37	0.20	-0.10
12	London	5.54	0.40	-0.09
13	Southern	5.58	0.20	-0.11
14	South Western	5.33	0.10	-0.17

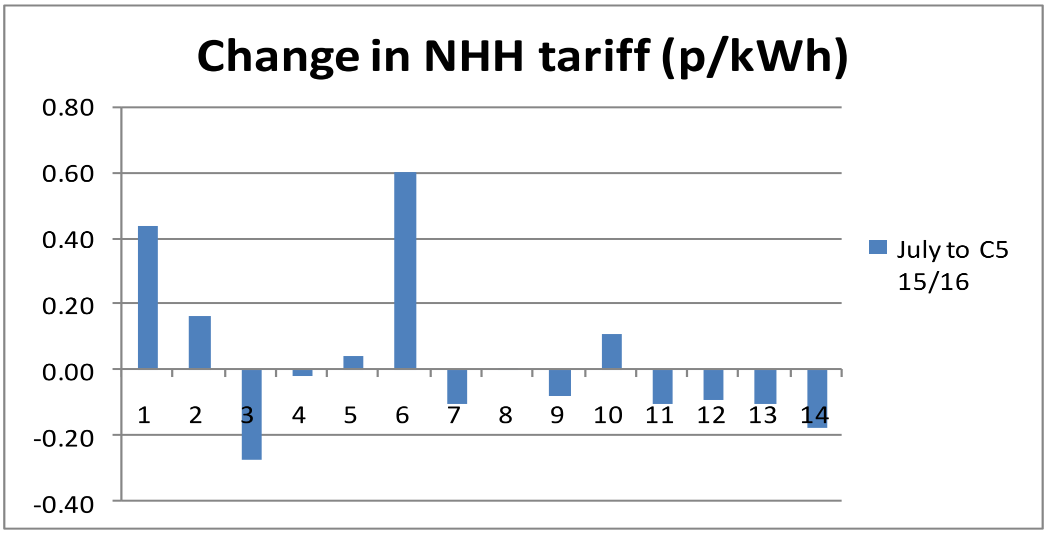

Figure 4

7 Sensitivities & Uncertainties for 2015/16

7.1 Transmission revenue requirements

The scenarios set out below are intended to illustrate the sensitivity of the forecast tariffs to changes in the revenue collected TNUoS tariffs. These scenarios do not represent a minimum and maximum tariff range.

Table 15 shows the impact of a 1% change in revenues, upon generation and demand tariffs. Since this affects the residual tariff component the impact is the same in all zones.

Table 15

Average Tariff Change for 1% change in revenue (+/- 26.13m)	**15/16 Revenue**
Generation	+/- £0.08/kW
HH Demand	+/- £0.36/kW
NHH Demand	+/-0.04p/kWh

7.2 Generation : Demand Split

Under the current CUSC methodology, tariffs are set to recover 27% of TNUoS revenue from generation and 73% from demand. EU Regulation ECR 838/2010 limits the amount that can be recovered from generation to an average of €2.5/MWh per annum. Due to increased revenues, lower demand and a stronger pound, this limit is forecast to be breached in 2015/16. CUSC modifications CMP224 and CMP227 are being considered which if implemented will adjust the balance of TNUoS charges between generation and demand to remain compliant with the regulation.

ACER (the Agency for the Cooperation of European Regulators) carried out a review of the appropriateness of the €2.5/MWh limit for the period beyond December 2014. Their opinion is that this limit should only apply to energy based charges and therefore Generation TNUoS tariffs, which are capacity based, would be exempt. However, it is not known if the European Commission will choose to make changes in line with ACER's opinion, make other changes it deems appropriate, or maintain the current limit before tariffs are fixed in January.

The proportion of TNUoS revenue to be recovered from generation (G) and from demand (D) is given by the formulas:

$$G <= \frac{EL}{RX}$$

$$D >= 1 - \frac{EL}{RX}$$

Where:

- G is the proportion of TNUoS revenue recovered from generation

- D is the proportion of TNUoS revenue recovered from demand
- E is the total energy consumed by demand over a year
- L is the average generator charge cap per kWh (Including any risk adjustment)
- R is the total TNUoS revenue to be recovered.
- X is the Euros/Sterling exchange rate

As the limit (L) is expected to be reached in 2015/16 an adjustment has been made to the proportions recovered from generation (G) and demand (D). In the absence of any increase in forecast energy (E) any increases in revenue (R) can only be recovered from demand decreasing the proportion recovered from generation and increasing the proportion from demand.

Table 16 shows the forecast generation and demand proportions for 2015/16 with 2014/15 also shown for comparison if the original version of CMP224 is approved. 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 resulting 77:23 revenue split is subject to change depending on revenues to be recovered and the energy forecast. The exchange rate is taken from the Office of Budgetary Responsibility Spring 2014 report.

Table 16

	2014/15	2015/16
G	**0.27**	**0.234**
D	**0.73**	**0.766**
E (TWh)	**322**	**319**
L (€/MWh)	**2.5**	**2.34**
R (£m)	**2,477.3**	**2,612.4**
X (€/£)	**1.2**	**1.22**

Appendix C contains tariffs based upon the above 23:77 split of revenue between generation and demand.

7.2.1 Generation and Demand Residuals

The following formulas detail how the residual element of generation and demand tariffs is calculated. This can be used to assess the sensitivity of the residual elements to assumptions. For example by changing G and D based on section 7.2 you can see how this then affects the residual element of the generation and demand tariffs. You can also adjust allowed revenues to see the effect of revenues changing as well as altering the generation and demand bases.

$$R_G = \frac{GR - Z_G - O - L_G}{B_G}$$

$$R_D = \frac{DR - Z_D}{B_D}$$

Where:

- R_G is the generator 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 the locational element of generator tariffs (£m)
- Z_D is the TNUoS revenue recovered from the locational element of demand tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_G is the TNUoS revenue recovered from onshore local tariffs (£m)
- B_G is the generator charging base (GW)
- B_D is the demand charging base (Half-hour equivalent GW)

Approximately 75% of offshore revenues are collected from offshore local tariffs. Therefore if **R** is reduced/increased due to changes in offshore revenues, then **O** should be reduced/increased by 75%, i.e. if revenue reduces by £10m, reduce O by £7.5m.

Table 17 shows the residual calculation for 2015/16 with 2014/15 included for comparison under current methodology.

Table 17 Residual Calculation under Current Methodology

	2014/15	2015/16
R_G (£/kW)	5.81	5.58
R_D (£/kW)	30.05	32.45
G(%)	0.27	0.27
D(%)	0.73	0.73
R (£m)	2,477.3	2,612.4
Z_G (£m)	54	55
Z_D (£m)	147	149
O (£m)	160	207.3
L_G (£m)	31	34.5
B_G (GW)	73	73.2
B_D (GW)	55.3	54.2

7.3 Demand charging base

An increase in the demand charging base decreases tariffs and vice versa. Table 18 shows the impact of a 500MW increase in the demand charging base. For simplicity this has been spread in proportion to the existing demand in each zone.

Table 18

Tariff change for 500MW increase in demand	Change to tariffs
HH Demand	-£0.32/kW
NHH Demand	+/- <0.01 p/kWh

7.4 Generation charging base

The contracted background may still change due to the actions of our customers. The tariffs presented in this document are based upon National Grid's current best view of what the contracted background will look like as of 31 October which is used to finalise the locational element of tariffs. The residual element of generation tariffs may continue to be adjusted after this date up to when tariffs are finalised in January 2015.

An increase in the generation charging base decreases tariffs and vice versa. Table 19 shows the impact of a 1GW increase / decrease in the generation charging base. For simplicity this has been spread in proportion to the existing generation in each zone.

Table 19

Tariff change for +/- 1GW generation change	Change to tariffs
Generation Tariff	-/+ £0.11/kW

7.5 Network Model

The October forecast update on TNUoS tariffs will revise the circuit model.

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. We expect to host webinars and attend the Transmission Charging Methodology Forum to discuss tariffs as they are updated through the year but we also welcome bilateral discussions should you have specific queries.

8.2 Publication of charging models

Customers can receive a copy of our charging model to conduct sensitivity analysis on alternative developments of generation and demand. This model will be based on the contracted TEC background which differs from National Grid's view that has been used to calculate the tariffs in this update. We are unable to provide a breakdown of our best view as it may be based on commercially sensitive information.

If you would like a copy of the model to be emailed to you, together with a user guide, please contact us via the details in section 9. 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.

9 Comments & Feedback

As part of our commitment to customers we welcome comments and feedback on the information contained in this statement. In particular, to ensure that information is provided and presented in a way that is of most use to customers, we would welcome specific feedback on:

- the level of numeric detail provided to explain tariff changes;
- the quality of the explanation given to describe and explain tariff changes;
- information that is not useful and could be omitted; and
- information that is missing that could be added.

These should be sent to:

Damian Clough
National Grid
Warwick Technology Park
Warwick
CV34 6DA

Damian.Clough@nationalgrid.com

01926 656416

Our commitment to UK Transmission Customers

- ► We will work closely with you to build a foundation for trust through open and honest relationships
- ► We will listen, understand your needs and expectations, and seek solutions that work for you
- ► We will help you understand our business so that we can work better together
- ► We will be accountable for delivering a clear and timely service
- ► We will seek and act upon your feedback

10 Appendices

Appendix A	Contracted Generation changes for 2015/16
Appendix B	Transmission Owner Revenues
Appendix C	Tariffs with adjusted Generation / Demand Split
Appendix D	Generation Zones

Appendix A: Contracted Generation changes for 2015/16

Table 20 provides details of contracted TEC changes notified between 17th March 2013 and July 1st. Other changes may have been made to our best view but these cannot be shown below due to commercial reasons.

Table 20

Station Name	Node	TEC	Change
AChruach Wind Farm	ACHR1Q	21.5	-3.45
	ACHR1R	21.5	-3.45
Lynemouth	BLYT20	0	-366
Carrington	CARR40	0	-910
Clyde Windfarm	CLYN2Q	331.8	-6
	CLYS2R	179.8	-3
Halsary Windfarm	MYBS1Q	14.25	14.25
	MYBS1R	14.25	14.25
Strathy Windfarm	STRW20	76	-150
West Burton	WBUR40	3319	27
Ewe Hill	EWEH10	0	-12
Aberdeen Bay Windfarm	ABBA10	0	-77
Aikengall Windfarm	WDOD10	0	-108
Dumnaglass Wind	DUNM10	94	-4.5

Appendix B: Transmission Owner Revenues

The following tables show forecast revenues for charging years 2013/14 and 2014/15 when tariffs for those years were set. Actual allowed revenue in those years may differ. The tables also show forecast revenues for charging year 2015/16 based upon information available at the time of writing.

All reasonable care has been taken in the preparation of these tables and the data therein. However, the forecasts are subject to change, especially where they are influenced by external stakeholders, and actual revenues may vary from those shown.

These tables are offered without prejudice and National Grid and other Transmission Owners do not accept or assume responsibility for the use of this information by any person and cannot be held responsible for any loss that might be attributed to the use of this data.

All monies are nominal 'money of the day' unless stated otherwise and are presented to the nearest hundred thousand pounds.

Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formula are constructed. Inflation and base rate forecasts have been derived by National Grid and are consistent across Onshore TO's.

Opening Base Revenue allowances reflect the figures authorised by Ofgem in the RIIO-ET1 Final Proposals.

National Grid collects Network Innovation Competition Funding on behalf of all Transmission Owners receiving payments. Network Innovation Competition Funding is therefore only shown on the National Grid table.

Generally, allowances that have been determined by Ofgem are shown whilst those for which determinations have yet to be made are not. This forecast contains as much information as can be currently made available whilst protecting commercially sensitive information and observing market disclosure considerations.

National Grid Revenue Forecast

Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	Notes
Updated:					22/07/2014			
Regulatory Year					2013/14	2014/15	2015/16	
Actual RPI					251.73			April to March average
RPI Actual		RPIAt	3A		1.1667			Office of National Statistics
Assumed Interest Rate		It	3A		0.50%	0.50%	0.50%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	1,342.3	1,443.8	1,475.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		-5.5	-100.0	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.5	4.7	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3A	ALL	3.1%	3.1%	2.7%	HM Treasury Forecast then 2.8% as per ET1 model
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	2.7%	3.1%	2.9%	HM Treasury Forecast then 2.8% as per ET1 model
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	2.5%	3.0%	3.2%	HM Treasury Forecast then 2.8% as per ET1 model
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2344	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1561.1**	**1732.7**	**1703.9**	
Pass-Through Business Rates	B1	RBt	3B	ALL			1.2	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.1	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt	3B	NG			2.0	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	3B	NG			3.8	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	3B	NG	2.6	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	3B	NG	271.3	312.2	333.2	13/14 & 14/15 Charge setting. Later from TSP Tab
SHE Transmission Pass-Through	B7	TSHt	3B	NG	172.5	214.0	226.2	13/14 & 14/15 Charge setting. Later from TSH Tab
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	105.4	218.4	277.3	13/14 & 14/15 Charge setting. Later from OFTO Tab
Embedded Offshore Pass-Through	B9	OFETt	3B	NG	0.6	0.4	0.4	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**3B**	**ALL**	**552.3**	**745.1**	**844.2**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	12.4		2.4	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			6.2	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			3.0	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**3A**	**ALL**	**12.4**	**0.0**	**11.5**	
Network Innovation Allowance	D	NIAt	3H	ALL	6.1	10.9	10.7	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	3I	NG	0.0	17.8	16.7	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt	3F	ALL			0.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	16.0	16.0	15.8	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	3A	NG	-1.6	3.4	0.0	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	3A	NG	-0.4	-1.3	0.0	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-2.7		56.4	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**		**ALL**	**2143.3**	**2524.6**	**2659.2**	
Termination Charges	B5			NG	2.6	0.0	0.0	
Pre-vesting connection charges	P			ALL	43.3	47.0	47.0	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**			**NG**	**2097.4**	**2477.7**	**2612.3**	
Final Collected Revenue	U	TNRt		ALL	2089.6	2477.7	2612.3	Licensee Actual/Forecast
Forecast Over / (Under) Recovery [V=U-T]	V			ALL	-53.7	0.0	0.0	
Forecast percentage change to Maximum Revenue M				**NG**		**17.8%**	**5.3%**	
Forecast percentage change to TNUoS Collected Revenue T				**NG**		**18.1%**	**5.4%**	

Scottish Power Transmission Revenue Forecast				**Updated:**	**02/07/2014**			
Description		**Licence Term**	**Special Condition**	**Applicable to**	**Yr t-1**	**Yr t**	**Yr t+1**	
Regulatory Year					**2013/14**	**2014/15**	**2015/16**	**Notes**
Actual RPI					251.73	-	-	April to March average
RPI Actual		RPIAt			1.1667	-	-	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	225.1	237.0	258.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		6.2	-2.8	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.1	0.8	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2344	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**261.8**	**292.9**	**316.8**	
Pass-Through Business Rates	B1	RBt	3B	ALL			-19.2	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0	0.0	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**0.0**	**-19.2**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.5		2.6	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			0.6	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			-0.2	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE			0.0	Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.5**	**0.0**	**3.0**	
Network Innovation Allowance	D	NIAt	3H	ALL	0.6	0.8	0.8	Licensee Actual/Forecast/Budget
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	25.5	29.3	34.6	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-0.8		8.7	Calculated by Licensee
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**287.6**	**323.0**	**344.7**	
Excluded Services	P	EXCt		SP, SHE	7.0	7.7	8.0	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	15.0	18.5	19.5	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**		**NG**	**279.6**	**312.2**	**333.2**	General System Charge
Final Collected Revenue	U	TNRt		ALL	271.3	312.2	333.2	Licensee Actual/Forecast
Forecast Over / (Under) Recovery [V=U-T]	V			ALL	-8.3	0.0	0.0	
Forecast percentage change to Maximum Revenue M				**ALL**		**12.3%**	**6.7%**	

SHE Transmission Revenue Forecast				Updated:	18/07/2014			
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year					2013/14	2014/15	2015/16	Notes
Actual RPI					251.73	-	-	April to March average
RPI Actual		RPIAt			1.1667	-	-	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	104.5	111.5	121.4	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		8.7	0.0	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		0.0	0.0	Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.163	1.205	1.234	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**121.6**	**144.9**	**149.9**	
Pass-Through Business Rates	B1	RBt	3B	ALL		-10.7	0.0	RBt rebate anticipated in 2014/15
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0	0.0	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**-10.7**	**0.0**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.0		0.0	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			0.0	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			0.0	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE			0.0	Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**0.0**	**0.0**	
Network Innovation Allowance	D	NIAt	3H	ALL	1.2	1.8	1.8	Licensee Actual/Forecast
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	54.5	70.8	79.53	Excludes Asset Adjusting Events impacts
Compensatory Payments Adjustment	J	SHCPt	3C	SHE	0.0	0.0	0.0	Licensee Actual/Forecast/Budget
Correction Factor	K	-Kt	3A	ALL	-2.8		-1.5	15/16 per 13/14
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**174.5**	**206.8**	**229.7**	
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	3.6	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**		**NG**	**171.0**	**203.4**	**226.2**	General System Charge
Final Collected Revenue	U	TNRt		ALL	175.9	217.4	229.7	Licensee Actual/Forecast
Forecast Over / (Under) Recovery [V=U-T]	V			ALL	1.5	10.6	0.0	
Forecast percentage change to Maximum Revenue M				**ALL**		**18.6%**	**11.1%**	

Offshore Transmission Revenue Forecast			Updated:	20/06/2014			
Description	Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year				2013/14	2014/15	2015/16	Notes
Barrow				5.3	5.5	5.6	Current revenues plus indexation
Gunfleet				6.6	6.9	7.0	Current revenues plus indexation
Walney 1				12.1	12.5	12.8	Current revenues plus indexation
Robin Rigg				7.5	7.7	7.9	Current revenues plus indexation
Walney 2				12.6	12.9	13.3	Current revenues plus indexation
Sheringham Shoal				15.6	18.9	19.6	Current revenues plus indexation
Ormonde				11.2	11.6	11.9	Current revenues plus indexation
Greater Gabbard				11.4	26.0	26.7	Current revenues plus indexation
London Array				23.0	37.6	37.7	Current revenues plus indexation
2014/15 OFTOs					40.4	72.0	National Grid forecast of those expected to transfer in 2014/15
2015/16 OFTOs						62.8	National Grid forecast of those expected to transfer in 2015/16
Offshore Transmission Pass-Through (B7)	**TOFTOt**	**3B**	**NG**	**105.4**	**179.9**	**277.3**	

Appendix C: Tariffs with adjusted Generation / Demand Split

The following tariffs have been calculated with a Generation / Demand split of 23.4% / 76.6%

Wider Generation Tariffs (£/kW)		
Zone	**Zone Name**	**15/16**
1	North Scotland	25.69
2	East Aberdeenshire	21.32
3	Western Highlands	23.73
4	Skye and Lochalsh	29.17
5	Eastern Grampian and Tayside	22.41
6	Central Grampian	21.06
7	Argyll	21.26
8	The Trossachs	17.87
9	Stirlingshire and Fife	17.03
10	South West Scotland	15.81
11	Lothian and Borders	13.11
12	Solway and Cheviot	11.63
13	North East England	8.38
14	North Lancs and The Lakes	7.74
15	South Lancs, Yorks and Humber	6.07
16	North Midlands and North Wales	4.66
17	South Lincs and North Norfolk	2.83
18	Mid Wales and The Midlands	1.88
19	Anglesey and Snowdon	7.13
20	Pembrokeshire	5.03
21	South Wales	2.45
22	Cotswold	-0.78
23	Central London	-5.36
24	Essex and Kent	-0.93
25	Oxfordshire, Surrey and Sussex	-2.58
26	Somerset and Wessex	-4.61
27	West Devon and Cornwall	-6.60

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	21.35	3.22
2	Southern Scotland	24.58	3.51
3	Northern	30.85	3.85
4	North West	33.79	4.76
5	Yorkshire	34.46	4.67
6	N Wales & Mersey	33.81	5.35
7	East Midlands	37.26	5.00
8	Midlands	38.00	5.29
9	Eastern	39.18	5.24
10	South Wales	36.46	4.88
11	South East	41.93	5.60
12	London	44.33	5.76
13	Southern	43.11	5.82
14	South Western	42.79	5.56

Appendix D: Generation Zones