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Tariff Information Paper

October 2014 forecast of TNUoS tariffs for 2015/16

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

17 October 2014

V1.0

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Any Questions?

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1 Executive Summary

This document provides our latest forecast of 2015/16 Transmission Network Use of System (TNUoS) tariffs, updating the previous forecast in July. The next forecast of 2015/16 tariffs will be in December and tariffs will be fixed at the end of January 2015.

Since April we have included a scenario in our forecasts which restricts annual average generator charges to €2.5/MWh in compliance with EU Regulation ECR 838/2010. Following the approval of CUSC Modification Proposal CMP224 and decreasing likelihood that the regulation will be modified before January, this is now our central view. Consequently the proportion of revenue to be recovered from generation has decreased from 27% to 23.3% with a corresponding increase in the proportion to be recovered from demand. After all other changes between July and October have been made, reducing the proportion of revenue collected from generation reduces average Generation tariffs by £1.32/kW, and increased average demand tariffs by £1.80/kW for HH tariffs and 0.18p/kWh for NHH tariffs.

We have increased our forecast of total transmission revenue from £2,612m to £2,633m. This reflects changes in onshore transmission owners' revenue forecasts based on information from the annual regulatory reporting process and recent decisions by Ofgem on Strategic Wider Works in Scotland and on the Anglo-Scottish border.

In July we changed our forecasts of chargeable demand. We have reviewed, but not changed, our forecast of peak demand and its distribution. We have also reviewed Non-Half-Hour chargeable energy and whilst the national total is unchanged from our July forecast, the distribution between zones has been changed in some places. There have been no changes to the demand data used to calculate the locational element of tariffs.

We have also updated the generation background to reflect our best view of the contracted position on 31 October 2014 and completed our annual update of circuit data.

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 onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, we use a model of power flows on the transmission system to determine the locational component of TNUoS tariffs. 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 is used 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, cable / overhead line, and 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 networks, 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 revenue that onshore and offshore transmission owners are allowed in their price controls or in the correct proportions between Generation and Demand. Therefore, separate, non-locational "residual" tariff elements are included in the generation and demand tariffs. The residuals are set to ensure that the correct amount of revenue is recovered and in the correct proportions.

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 and use of circuits between their connection and the MITS. These charges are therefore locational and specific to individual generators.

We produce an initial view of tariffs fourteen months before the charging year starts. Over time the data used in the model is updated until the tariffs are finalised two months ahead of the charging year. The degree of uncertainty in the forecasts reduces as we get closer to publishing tariffs at the end of January. Scenarios are provided in some cases to show the impact of uncertainties that could have a significant impact on tariffs.

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 forecast published in July can be found in later sections. Tariffs are set based on the current methodology which leads to a Generation and Demand split of 23.3 percent contribution by generation and 76.7 percent contribution by demand.

3.1 Generation Tariffs 2015/16

Table 1 – Generation Wider Tariffs

2015/16 Wider Generation Tariffs		
Zone	**Zone Name**	**£/kW**
1	North Scotland	25.43
2	East Aberdeenshire	20.98
3	Western Highlands	23.37
4	Skye and Lochalsh	28.80
5	Eastern Grampian and Tayside	22.20
6	Central Grampian	21.53
7	Argyll	22.75
8	The Trossachs	17.88
9	Stirlingshire and Fife	16.98
10	South West Scotland	15.68
11	Lothian and Borders	13.23
12	Solway and Cheviot	11.46
13	North East England	8.39
14	North Lancs and The Lakes	7.49
15	South Lancs, Yorks and Humber	6.04
16	North Midlands and North Wales	4.79
17	South Lincs and North Norfolk	2.93
18	Mid Wales and The Midlands	1.98
19	Anglesey and Snowdon	7.36
20	Pembrokeshire	5.25
21	South Wales	2.51
22	Cotswold	-0.69
23	Central London	-5.23
24	Essex and Kent	-0.78
25	Oxfordshire, Surrey and Sussex	-2.46
26	Somerset and Wessex	-4.49
27	West Devon and Cornwall	-6.49
Small generators discount		9.71

Table 2 – Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.180108	0.103033	0.074237
<1320 MW	Redundancy	0.396763	0.245479	0.178533
>=1320 MW	No redundancy	-	0.323053	0.233634
>=1320 MW	Redundancy	-	0.530372	0.387127

Table 3 – Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.43	Didcot	0.23	Kilmorack	0.18
Afton	2.09	Dinorwig	2.16	Langage	0.59
Aigas	0.59	Dumnaglass	3.51	Lochay	0.33
An Suidhe	2.24	Dunlaw Extension	1.30	Luichart	1.02
Arecleoch	1.62	Edinbane	6.14	Marchwood	0.34
Baglan Bay	0.67	Fallago	0.97	Mark Hill	-0.79
Black Law	0.90	Farr Windfarm	2.15	Millennium Wind	1.46
Blacklaw Extension	1.13	Ffestiniogg	0.23	Mossford	3.56
Bodelwyddan	0.10	Finlarig	0.29	Nant	-1.10
Brochloch	1.92	Foyers	0.69	Neilston	2.14
Carraig Gheal	3.95	Glendoe	1.65	Rocksavage	0.02
Clyde (North)	0.10	Glenmoriston	1.18	Saltend	0.30
Clyde (South)	0.11	Gordonbush	2.37	South Humber Bank	0.94
Corriegarth	1.40	Griffin Wind	1.68	Spalding	0.27
Corriemoillie	2.47	Hadyard Hill	1.43	Strathy Wind	-1.32
Coryton	0.05	Harestanes	4.79	Whitelee	0.10
Cruachan	1.60	Hartlepool	0.53	Whitelee Extension	0.26
Crystal Rig	0.37	Hedon	0.18		
Culligran	1.55	Invergarry	1.27		
Deanie	2.55	Kilbraur	2.11		
Dersalloch	3.83	Killingholme	0.40		

Table 4 – Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg	-0.42	27.49	8.52
Robin Rigg West	-0.42	27.49	8.52
Gunfleet	15.71	14.42	2.70
Barrow	7.26	37.97	0.94
Ormonde	22.44	41.80	0.33
Walney 1	19.36	38.56	0.00
Walney 2	19.22	38.90	0.00
Sheringham Shoal	21.68	25.42	0.55
Greater Gabbard	13.61	31.27	0.00
London Array	9.23	31.45	0.00

3.2 Demand Tariffs 2015/16

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

Table 5 – Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	22.30	3.22
2	Southern Scotland	25.35	3.37
3	Northern	31.26	4.10
4	North West	34.38	4.69
5	Yorkshire	34.93	4.99
6	N Wales & Mersey	34.36	5.47
7	East Midlands	37.59	5.03
8	Midlands	38.48	5.32
9	Eastern	39.60	5.32
10	South Wales	36.81	5.13
11	South East	42.25	5.61
12	London	44.68	5.81
13	Southern	43.47	5.91
14	South Western	43.19	5.70

4 Updates to the 2015/16 Charging Model

Since the July forecast of tariffs, updates have been made to the circuit data, contracted generation background, generation charging base, total revenue and demand charging base. There have also been minimal changes to the transport model demand data following an update to embedded generation.

4.1 Changes influencing the locational element of tariffs

4.1.1 Generation

Tariffs will be set using the contracted position on 31 October 2014. Tariffs in this forecast are based upon our best view of the generation that will be contracted on 31 October so as this date approaches our best view and contracted TEC will converge. There has been only one change of significance in our best view since the July forecast, where a generator that was expected to remove its contracted TEC from 2015/16 will not now complete the contractual changes before 31 October 31 and has therefore been included in this forecast.

Table 6 shows the total contracted and modelled Generation TEC in this forecast compared to previous forecasts and 2014/15. Changes in contracted TEC since the July forecast can be found in Appendix A.

Table 6 - Contracted and Modelled TEC

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast
Contracted TEC	77.2	80.3	78.8	78.7
Modelled TEC	77.2	79.5	77.9	78.4

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, 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 July forecast and this will not change before charges are finalised in January 2015. However, embedded generation and directly connected demand have been updated since July resulting in a small change in embedded generation for 2015/16 (embedded generation reduces demand).

Table 7 - Transport Model Demand (GW)

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast
Transport Model Demand	56.6	55.6	55.7	55.7

4.1.3 Network Model Changes

Network model data has been updated in this forecast using information received from the various transmission owners in 2014 as part of the Electricity Ten Year Statement process (ETYS). Previous forecasts were based on a view of what the network would look like in 2015/16 using data received in 2013.

A change in connectivity between Crossaig and Hunterston, which is part of the Kintyre - Hunterston subsea cable project, results in an increase in flows across the subsea cable. Flows have also increased across this circuit due to a forecast reduction in the impedance of assets associated with this scheme. As cable is more expensive than OHL per km, any increase in flows across this circuit will increase tariffs for Generators whose incremental km flow across this circuit.

The upgrade of existing routes between Strathaven and Wishaw and between Wishaw, Kaimes and Smeaton, which are part of the East West Reinforcement scheme, are now scheduled to be completed a year later (2016/17). This, coupled with the removal of a temporary overhead line between Lambhill and Longannet, part of the Beauly Denny scheme, a year earlier than previously forecasted, affects flows mainly in Scotland but also further South.

Large changes in network data are not expected between now and final tariffs. However, changes may still be made as the auditing of data between TO's as part of the ETYS process has not yet been completed.

4.2 Changes influencing the residual element of tariffs

4.2.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs) in Great Britain. The revenues of onshore TOs are subject to RIIO price controls set by Ofgem at periodic price reviews. RIIO stands for Revenue = Incentives + Innovation + Outputs. Revenue is initially set at a price review and then adjusted during the price control period depending on performance against incentives, innovation and outputs delivered. Revenue adjustments are generally lagged by two years so allowed revenue in 2015/16 will be adjusted by Ofgem in November 2014 to reflect outputs and performance in 2013/14.

The revenues of offshore TOs (OFTO) 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 revenue and when it will start. Therefore, whilst the revenues for existing OFTOs can be predicted by indexing previous year revenues, the revenue for new OFTOs has to be forecast.

Table 8 shows the forecast 2015/16 revenues that have been used in this tariff forecast. Earlier forecasts and the final revenue upon which 2014/15 tariffs were set are also included for comparison. Further detail can be found in Appendix B.

Table 8 – Allowed Revenues

£m Nominal	2014/15 TNUoS Revenue	2015/16 TNUoS Revenue			
	Jan 2014 Final	Jan 2014 Initial View	April 2014 Update	July 2014 Update	Oct 2014 Update
National Grid					
Price controlled revenue	*1,761.9*	*1,855.6*	*1,851.6*	*1,805.9*	*1,810.9*
Less income from connections	*47.0*	*47.0*	*47.0*	*47.0*	*47.0*
Income from TNUoS	**1,714.9**	**1,808.7**	**1,804.6**	**1,759.0**	**1,763.9**
Scottish Power Transmission					
Price controlled revenue	*323.0*	*342.3*	*341.6*	*344.7*	*322.8*
Less income from connections	*10.8*	*9.8*	*9.8*	*11.5*	*10.8*
Income from TNUoS	**312.2**	**332.5**	**331.8**	**333.2**	**312.0**
SHE Transmission					
Price controlled revenue	*217.4*	*219.3*	*218.7*	*229.7*	*270.3*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.6*	*3.6*
Income from TNUoS	**214.0**	**215.7**	**215.2**	**226.2**	**266.8**
Offshore	**218.4**	**276.4**	**276.4**	**277.3**	**274.1**
Network Innovation Competition	**17.8**	**16.7**	**16.6**	**16.7**	**16.7**
Total to Collect from TNUoS	**2,477.3**	**2,650.0**	**2,644.7**	**2,612.3**	**2,633.4**

Individual Transmission Owner revenue forecasts have been updated since the July forecast to reflect changes in forecast inflation and information from the annual regulatory reporting process. Following announcements by Ofgem since the July forecast, additional revenue has also been included for critical investments

Critical investments are generally large projects with revenue set by Ofgem on a case by case basis rather than directly through the RIIO price control. Beauly – Mossford, Kintyre – Hunterston and additional works on the Anglo-Scottish interconnector have been included in this forecast. Caithness – Moray has not been included because funding is still to be consulted upon.

Forecasts of revenue adjustments and critical investment allowances have been included to provide a reasonable view of TNUoS tariffs in 2015/16. The actual adjustments announced by Ofgem in November could be higher or lower depending on its view of outputs, financial parameters and how costs should be treated.

The Offshore Transmission Owners (OFTOs) revenue forecast is slightly lower than the July forecast due to lower inflation in 2014. Existing OFTOs include Barrow, Gunfleet, Walney 1 & 2, Robin Rigg, Sheringham Shoal, Ormonde, London Array and Greater Gabbard. OFTOs expected to be appointed in 2014/15 are Lincs, Gwynt y Môr, Thanet, and West of Duddon

Sands. OFTOs expected to be appointed in 2015/16 are Humber Gateway and Westermost Rough.

Ofgem can award up to £27m (2009/10 prices) per year for innovation projects under the electricity transmission Network Innovation Competition Fund. National Grid collects the revenue for this fund on behalf of the successful bidders. This forecast assumes 50% of this allowance will be awarded. The electricity distribution equivalent of this fund will not require funding from TNUoS tariffs until 2016/17 so is not included in this forecast.

4.2.2 Generation: Demand Split

Since March 2011, EU Regulation ECR 838/2010 has limited the average annual charge to generators to €2.5/MWh per annum. With rising revenues, a stronger pound and reduced net demand, this limit is forecast to be breached in 2015/16. 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 was that capacity based infrastructure charges such as TNUoS should not be limited. However, the regulation does not automatically enact this opinion and we are currently unaware of any moves by the EU to implement it.

CUSC Modification Proposal 224 was approved by Ofgem on 8 October 2014. This introduces the ability to vary the proportion of revenue recovered from generators if the €2.5/MWh limit would otherwise be breached. Therefore we are forecasting that the proportion of revenue collected rom generation will be reduced to 23.3% in 2015/16. Previously, the CUSC methodology fixed this proportion at 27.0%.

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

$$G <= \frac{E.L}{R.X}$$

$$D >= 1 - \frac{E.L}{R.X}$$

Where:

- G is the proportion of TNUoS revenue recovered from generation
- D is the proportion of TNUoS revenue recovered from demand
- E is the forecast annual generator output
- 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 Euro/Sterling exchange rate

Table 9 shows the forecast generation (G) and demand (D) proportions for 2015/16 with 2014/15 also shown for comparison. A 7% risk margin has been applied to the €2.5/MWh limit (L) reflecting year-ahead allowed revenue (R) and annual generator output (E) forecasting accuracy. The limit on annual average generation charges is therefore €2.34/MWh.

The resulting 23.3:76.7 revenue split between generation and demand is still subject to changes in forecast revenue and annual generator output. However, the CMP224 methodology fixes the exchange rate for 2015/16 using the Office of Budgetary Responsibility March 2014 report.

Table 9 – G/D Split Calculation

	2014/15	2015/16
G	0.27	0.233
D	0.73	0.767
E (TWh)	322.0	319.6
L (€/MWh)	2.50	2.34
R (£m)	2,477.3	2,633.4
X (€/£)	1.20	1.22

4.2.3 Generation and Demand Residuals

The residual element of generation and demand tariffs can be calculated using the following formulae:

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

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

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)

Table 10 shows the residual calculation for 2015/16 with 2014/15 included for comparison. The formulae above can be used to calculate tariffs under different scenarios. To re-calculate the tariff, deduct the residual shown in Table 10 from the tariffs in Section 3 and then add the alternative residual calculated using the above formulae.

Note that 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 10 – Residual Calculation

		2014/15	2015/16
R_G (£/kW)	Generator residual tariff	5.81	4.43
R_D (£/kW)	Demand residual tariff	30.05	34.41
G (%)	Proportion of revenue recovered from generation	0.270	0.233
D (%)	Proportion of revenue recovered from demand	0.730	0.767
R (£m)	Total TNUoS revenue	2,477.3	2,633.4
Z_G (£m)	Revenue recovered from the locational element of generator tariffs	54.0	47.0
Z_D (£m)	Revenue recovered from the locational element of demand tariffs	147.0	154.8
O (£m)	Revenue recovered from offshore local tariffs	160.0	205.5
L_G (£m)	Revenue recovered from onshore local tariffs	31.0	34.6
B_G (GW)	Generator charging base	73.0	73.6
B_D (GW)	B_D is the demand charging base	55.3	54.2

4.3 Charging bases for 2015/16

Generation

The generation base for 2015/16 takes generation from the transport model (see section 4.1.1) less;

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

Demand

Demands in 2013/14 were lower than forecast which resulted in an under-recovery of allowed revenue. This can largely be attributed to the milder than normal weather during 2013/14. Nonetheless the demand charging base has been reviewed to remove any bias in the probability of under or over-recovery.

Peak demand and the distribution of peak demand between zones were reviewed in the July update. Zone 6 (North Wales and Merseyside) demand increased from 4.81% to 5.45% of peak demand as a result of this exercise, which was attributable to the closure of Shotton CHP in 2012. Peak demand forecasts have not changed in this update.

The July update also included a revised forecast of 28.35TWh for Non-Half Hour (NHH) metered demand, i.e. the chargeable energy between 4 pm and 7pm each day. This forecast has not changed but the distribution between zones has been further reviewed with some minor amendments. The proportions of peak demand due to HH and NHH demand has also been reviewed. Nationally, NHH demand continues to contribute 71% of peak demand with minor adjustments in some zones.

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 – Interconnectors

Interconnector	Zone	Transport Model (Generation MW)	Charging Base (Generation MW)
French - Sellindge 400kV	24	2000	0
Britned - Grain 400kV	24	1200	0
East West - Deesside 400kV	16	500	0
Moyle - Auchencrosh 275kV	10	295	0

4.4 Expansion Constant

The expansion constant has been updated from the July forecast due to a reduction in forecast RPI from 2.7% to 2.6%. The Expansion Constant now equals £13.239632/MWkm.

5 Forecast generation tariffs for 2015/16

The following section provides details of the forecast wider and local generation tariffs for 2015/16. Note these use a 23.3:76.7 Generator/Demand split to comply with EU Regulation 838/2010.

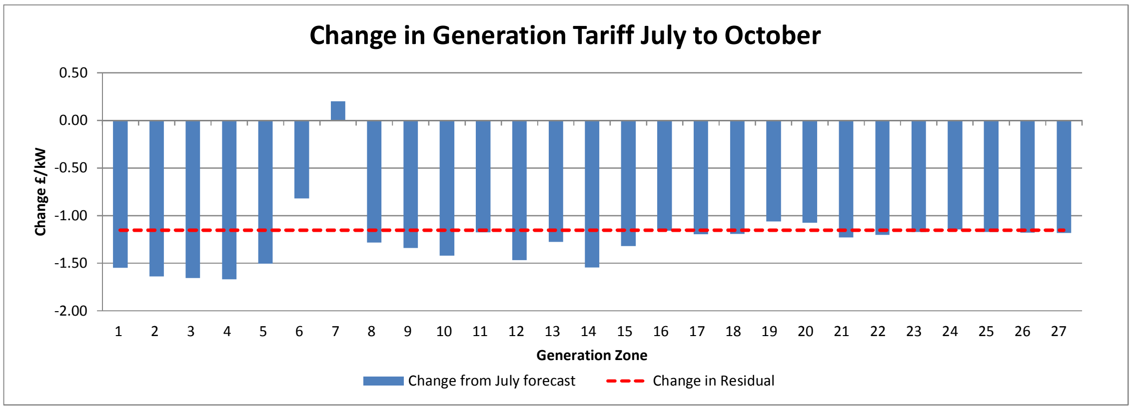
Table 12 shows the forecast generation zonal TNUoS tariffs for 2015/16 as well as changes from the July forecast. Changes to the 2014/15 tariffs are also shown for comparison purposes. Figure 1 shows the change from the July forecast graphically.

An explanation of changes between years can be found in previous forecasts so is not repeated in this update.

Table 12 - Wider Generation Charges

Wider Generation Tariffs (£/kW)				
Zone	Zone Name	2015/16	Change from 2014/15 tariff	Change from July forecast
1	North Scotland	25.43	-2.24	-1.55
2	East Aberdeenshire	20.98	-1.99	-1.64
3	Western Highlands	23.37	-4.98	-1.66
4	Skye and Lochalsh	28.80	-5.00	-1.67
5	Eastern Grampian and Tayside	22.20	-1.83	-1.50
6	Central Grampian	21.53	-0.44	-0.82
7	Argyll	22.75	1.90	0.20
8	The Trossachs	17.88	-0.54	-1.28
9	Stirlingshire and Fife	16.98	-1.04	-1.34
10	South West Scotland	15.68	-0.78	-1.42
11	Lothian and Borders	13.23	-0.95	-1.17
12	Solway and Cheviot	11.46	-1.26	-1.47
13	North East England	8.39	-1.48	-1.28
14	North Lancs and The Lakes	7.49	-1.66	-1.54
15	South Lancs, Yorks and Humber	6.04	-1.57	-1.32
16	North Midlands and North Wales	4.79	-1.37	-1.16
17	South Lincs and North Norfolk	2.93	-1.72	-1.19
18	Mid Wales and The Midlands	1.98	-1.57	-1.19
19	Anglesey and Snowdon	7.36	-1.21	-1.06
20	Pembrokeshire	5.25	-1.31	-1.07
21	South Wales	2.51	-1.27	-1.23
22	Cotswold	-0.69	-1.44	-1.20
23	Central London	-5.23	-1.45	-1.17
24	Essex and Kent	-0.78	-2.21	-1.14
25	Oxfordshire, Surrey and Sussex	-2.46	-1.62	-1.17
26	Somerset and Wessex	-4.49	-1.79	-1.18
27	West Devon and Cornwall	-6.49	-1.79	-1.18

Figure 1 - Generation Tariff Changes



Residual Tariff

The Residual tariff has decreased by £1.15/kW to £4.43/kW since the last forecast in July. This is mainly due to the change in the proportion of revenue recovered by generation reducing from 27.0% to 23.3% due to the effect of CMP224 and EU Regulation 838/2010.

Locational Tariff

Zone 6 has a smaller than average decrease in tariffs due to a change in direction of flows along a relatively long circuit between Killin and Errochty which previously offset the MWkm of generators in this zone. This change comes about due to a reduction in forecast generation outside of this zone. While this change limits the decrease in tariffs in Zone 6 it adds to the decrease in tariffs in Zones 1 to 5.

Zone 7's has a small net rise in tariffs due to circuit changes around Crossaig resulting in flows along the Crossaig to Hunterston subsea cable.

The increase in contracted generation in the South reduces North to South flows which reduces generation tariffs in northern zones 1 to 14, with the exception of zones 6 and 7 for the reasons described above.

Zones 19 and 20 have smaller than average reductions in tariffs due to generation changes.

5.1 Onshore local substation tariffs

Local substation tariffs (Table 2 in Section 3) have dropped slightly from the July forecast due to the forecast RPI rate used to inflate tariffs dropping from 2.7% to 2.6%.

5.2 Offshore local generation tariffs

The local offshore tariffs (Table 4, Section 3) have changed from the July forecast due to the forecast of inflation dropping from 2.7% to 2.6%.

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 £9.85/kW.

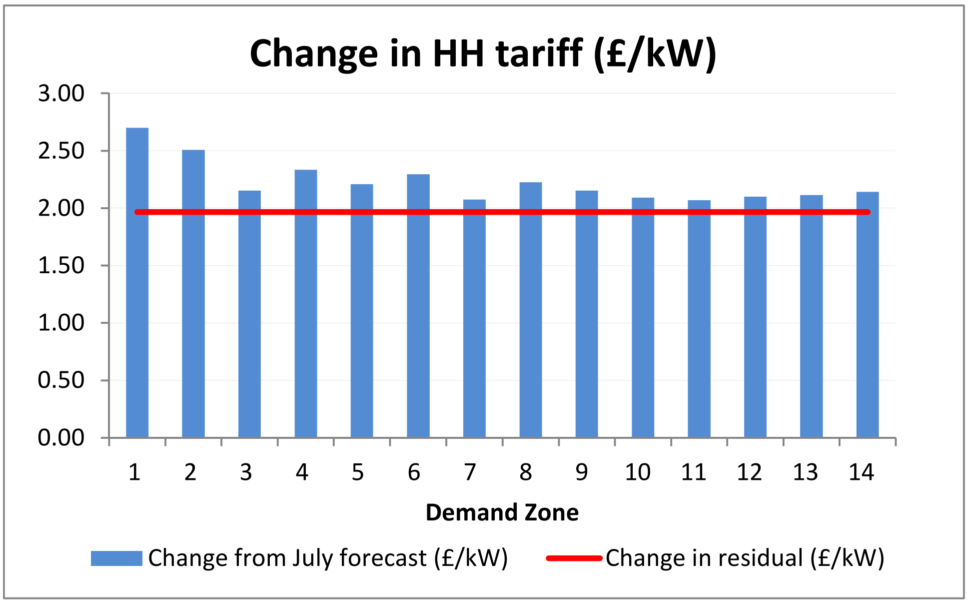
6 Forecast 2015/16 Demand Tariffs

Table 13 shows the 2015/16 Half-Hour (HH) demand tariffs. Changes from 2014/15 and the July forecast are shown for comparison. Figure 2 shows the change from the July forecast graphically.

Table 13 – HH Demand Tariffs

Zone	Zone Name	2015/16 (£/kW)	Change from 2014/15 (£/kW)	Change from July forecast (£/kW)
1	Northern Scotland	22.30	6.13	2.70
2	Southern Scotland	25.35	4.11	2.51
3	Northern	31.26	4.32	2.15
4	North West	34.38	4.74	2.34
5	Yorkshire	34.93	4.68	2.21
6	N Wales & Mersey	34.36	4.65	2.30
7	East Midlands	37.59	4.49	2.07
8	Midlands	38.48	4.70	2.23
9	Eastern	39.60	4.97	2.16
10	South Wales	36.81	4.49	2.09
11	South East	42.25	4.59	2.07
12	London	44.68	6.14	2.10
13	Southern	43.47	4.69	2.11
14	South Western	43.19	4.49	2.14

Figure 2 – HH Demand Tariff Changes



Residual Tariff

The residual element of HH demand tariffs, which is the same for each zone, is shown as a red line in Figure 2. The residual ensures that the correct total revenue is recovered and has increased by £1.97/kW to £34.41/kW. The majority of this increase is due to the increase in proportion of revenue recovered from demand from 73.0% to 76.7%. There has also been a £21m increase in revenue to be recovered.

Locational Tariff

Individual tariffs have all increased more than the residual. This is partly a consequence of the revised G/D split which affects the proportions of revenue recovered from the locational element of tariffs as well as the residual elements.

Forecast changes in generation will reduce north to south flows. This limits southern demand tariff increases and adds to northern demand tariff increases. Locational Demand tariffs tend to reflect the inverse change of generation tariffs. Whilst this is generally the case some of the zonal changes are smoothed out by larger demand zones.

6.1 NHH Demand Tariffs

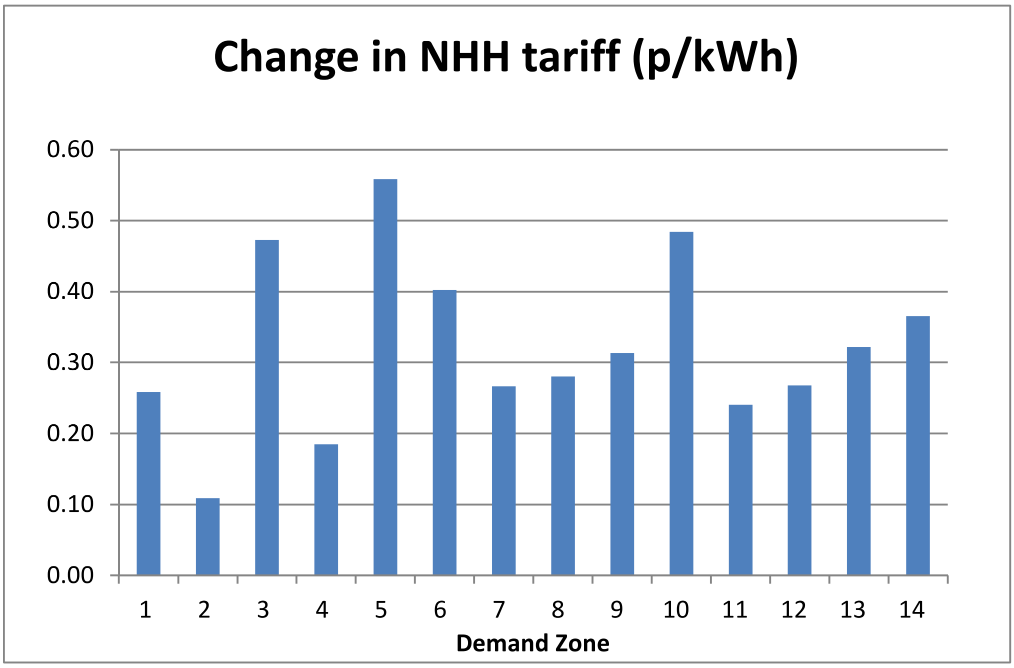
Table 14 and Figure 3 show the difference in the Non-Half-Hourly (NHH) demand tariffs between this and the July forecasts. Since the July forecast, the proportion of peak demand that is attributable to NHH customers has been reviewed and revised where appropriate. However, nationally NHH continues to contribute 71% of peak demand. The zonal distribution of NHH demand has also been revised.

On average the NHH tariff has increased by 0.22p/kWh since the July forecast. 0.18p/kWh of this increase is due to the revised G/D split.

Table 14

Zone	Zone Name	Tariffs 15/16 (p/kWh)	Change from 14/15 tariff (p/kWh)	Change July - October forecast (p/kWh)
1	Northern Scotland	3.22	1.03	0.26
2	Southern Scotland	3.37	0.42	0.11
3	Northern	4.10	0.44	0.47
4	North West	4.69	0.45	0.18
5	Yorkshire	4.99	0.88	0.56
6	N Wales & Mersey	5.47	1.28	0.40
7	East Midlands	5.03	0.45	0.27
8	Midlands	5.32	0.58	0.28
9	Eastern	5.32	0.57	0.31
10	South Wales	5.13	0.86	0.48
11	South East	5.61	0.44	0.24
12	London	5.81	0.67	0.27
13	Southern	5.91	0.53	0.32
14	South Western	5.70	0.46	0.37

Figure 3 – Change in NHH Tariff



7 Sensitivities & Uncertainties for 2015/16

7.1 Transmission Revenue

Decisions by Ofgem are expected this autumn which may impact upon allowed revenues in 2015/16. They include:

7.1.1 Adjustments to allowed revenue

In July 2014, the onshore transmission owners provided data on their outputs and costs during 2013/14 as part of the annual regulatory reporting process. Ofgem is currently considering these submissions and is expected to determine adjustments to base allowances in November. These adjustments will be reflected in the MOD term referred to in Appendix B.

The MOD determinations this November will relate to costs and outputs in the RIIO-T1 price control period for the first time. There is uncertainty around how some RIIO-T1 costs will be treated and therefore uncertainty in forecasting this November's MOD determinations. The onshore transmission owners have provided forecasts to remove the bias in this uncertainty but there is up and down side to these forecasts.

7.1.2 Awards for outputs

The RIIO-T1 price control includes mechanisms for Ofgem to reward environmental performance, stakeholder engagement and innovation. Table 15 lists awards still to be announced. How much of these potential awards has been included in the tariff forecast is also shown for information.

Network Innovation Competition Funding is collected on behalf of Transmission Owners only. An equivalent fund for Distribution Network Owners is being established under the Electricity Distribution Price Control. The Distribution fund will also be collected through TNUoS charges but this will not apply in 2015/16.

Table 15 – Output Awards

	Included in forecast (£m)	Maximum (£m)
Environmental Discretionary Rewards	0.0	4.0
Stakeholder Engagement Awards	0.0	2.3
Network Innovation Competition Funding	16.7	33.3
Total	**16.7**	**39.6**

7.1.3 Critical Investments

Ofgem has made decisions on Beauly-Mossford, Kintyre-Hunterston and additional Anglo-Scottish works since the July forecast. The additional revenues arising from these decisions will be reflected in the MOD determinations this autumn. Estimates of the effect of these decisions have been included in this forecast to reduce the bias in the allowed revenue uncertainty referred to above.

Ofgem has also decided there is a case for the £1.2bn Caithness-Moray project. Ofgem is expected to begin consultation on funding in late October and it is not included in this forecast.

7.1.4 Offshore Transmission Owners

Offshore transmission owners (OFTOs) receive their allowed revenue in monthly instalments beginning from when asset transfer takes place. In addition, they receive a one off payment for the tender cost assessment in the month of transfer.

Four OFTOs are expected to be appointed and take ownership of assets during 2014/15. If any of these are deferred into 2015/16 then the one off payment will be added to 2015/16 revenues but there may be less than twelve monthly payments depending on the transfer date.

Two OFTOs are expected to be appointed and take ownership of assets during 2015/16. Estimated lump sum payments have been included in the tariff forecasts for 2015/16 together with estimated monthly payments based on forecast transfer dates. Variation in valuations or transfer dates could increase or decrease the revenue requirements for these networks.

7.1.5 Effect on tariff residuals

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 16 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 16 – Tariff Sensitivity to Revenue

Average Tariff Change for 1% change in revenue (+/- 26.45m)	15/16 Revenue
Generation	+/- £0.08/kW
HH Demand	+/- £0.38/kW
NHH Demand	+/-0.05p/kWh

7.2 Demand charging base

An increase in the demand charging base decreases tariffs and vice versa. Table 17 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 17 – Tariff Sensitivity to Demand

Tariff change for 500MW increase in demand	Change to tariffs
HH Demand	-£0.35/kW
NHH Demand	-/+ <0.01 p/kWh

7.3 Generation charging base

The contracted background may still change before tariffs are finalised in January 2015. 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.

An increase in the generation charging base decreases tariffs and vice versa. Table 18 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 18 – Tariff Sensitivity to Generation

Tariff change for +/- 1GW generation change	Change to tariffs
Generation Tariff	-/+ £0.07/kW

8 Tools and Supporting Information

8.1 Further Information

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

8.2 Charging forums

We will be hosting a webinar in early November 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. In addition we will be discussing this report at the next Transmission Charging Methodology Forum.

8.3 Charging models

We can provide a copy of our charging model to allow you to conduct sensitivity analysis on our assumptions and scenarios. The 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 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/

8.5 Contact Details

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9 Appendices

Appendix A Contracted Generation changes for 2015/16

Appendix B Transmission Owner Revenues

Appendix C Generation Zones

Appendix A: Contracted Generation changes for 2015/16

Table 19 provides details of contracted TEC changes notified between July and September 2014. Other changes may have been made to our best view but these cannot be shown below due to commercial reasons.

Table 19 – TEC Changes

Station Name	Node	Revised TEC	Change
Pogbie Wind Farm	DUNE10	11.8	11.8
Grain	GRAI40	1,517.0	- 7.0
Wilton	GRST20	99.0	- 42.0
Halsary Windfarm	MYBS1Q	-	- 14.3
	MYBS1R	-	- 14.3

Appendix B: Transmission Owner Revenues

The following tables show revenues for charging years 2013/14 to 2014/15. Actuals are shown for 2013/14 and tariff setting forecasts are shown for 2014/15 and 2015/16.

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.

This forecast contains as much information as can be currently made available whilst protecting commercially sensitive information and observing market disclosure considerations. In some cases estimates have been used where information is not yet publically available. These estimates are intended to remove excessive bias from the forecast tariffs so that the final outcome is as likely to be higher as it is to be lower.

National Grid Revenue Forecast				**Updated:**		**26/09/2014**		
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	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%	2.5%	HM Treasury Forecast then 2.8% as per ET1 model
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	2.7%	3.1%	3.1%	HM Treasury Forecast then 2.8% as per ET1 model
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	2.5%	3.0%	3.3%	HM Treasury Forecast then 2.8% as per ET1 model
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2353	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1561.1**	**1732.7**	**1705.1**	
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	312.0	13/14 & 14/15 Charge setting. Later from TSP Tab
SHE Transmission Pass-Through	B7	TSHt	3B	NG	172.5	214.0	266.8	13/14 & 14/15 Charge setting. Later from TSH Tab
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	105.4	218.4	274.1	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]					552.3	745.1	860.4	
Reliability Incentive Adjustment	**C1**	**RIt**	**3C**	**ALL**	**12.4**		**2.4**	
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			8.7	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	14.1	
Network Innovation Allowance	**D**	**NIAt**	**3H**	**ALL**	**6.1**	**10.9**	**10.7**	
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		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	2.0	1.8	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	3A	NG	-0.4	-0.3	-0.6	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	0	ALL	2143.2	2524.3	2680.4	
Termination Charges	**B5**			**NG**	**2.6**	**0.0**	**0.0**	
Pre-vesting connection charges	P			ALL	43.3	47.0	47.0	
TNUoS Collected Revenue [T=M-B5-P]	T			NG	2097.4	2477.3	2633.4	
Final Collected Revenue	**U**	**TNRt**		**ALL**	**2089.6**			
Over / (Under) Recovery [V=U-M]	V			ALL	-53.7			
Forecast percentage change to Maximum Revenue M				NG		0.2	0.1	
Forecast percentage change to TNUoS Collected Revenue T				**NG**		**18.1%**	**6.3%**	

Scottish Power Transmission Revenue Forecast				**Updated:**	**07/10/2014**			
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	-22.1	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	1.2353	National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**261.8**	**292.9**	**293.2**	
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			1.9	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**	**4.3**	
Network Innovation Allowance	D	NIAt	3H	ALL	0.6	1.0	1.2	Licensee Actual/Forecast/Budget
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	25.5	29.2	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**	**323.1**	**322.8**	
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	18.8	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**		**NG**	**279.6**	**312.3**	**312.0**	General System Charge
Final Collected Revenue	U	TNRt		ALL	271.3			Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	-8.3			
Forecast percentage change to Maximum Revenue M				**ALL**		**12.3%**	**-0.1%**	

SHE Transmission Revenue Forecast				Updated:	07/10/2014			
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	124.1	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		8.7	30.0	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	1.1630	1.2051	1.2353	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**121.6**	**144.9**	**190.4**	
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	79.6	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; and 16/17 per RBt rebate in 14/15
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**174.5**	**206.8**	**270.3**	
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**	**266.8**	General System Charge
Final Collected Revenue	U	TNRt		ALL	175.9			Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	1.5			
Forecast percentage change to Maximum Revenue M				**ALL**		**18.6%**	**30.7%**	

Offshore Transmission Revenue Forecast			Updated:	26/09/2014			
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	37.6	Current revenues plus indexation
2014/15 OFTOs					78.9	99.0	National Grid forecast of those expected to transfer in 2014/15
2015/16 OFTOs						32.6	National Grid forecast of those expected to transfer in 2015/16
2016/17 OFTOs							National Grid forecast of those expected to transfer in 2016/17
2017/18 OFTOs							National Grid forecast of those expected to transfer in 2017/18
2018/19 OFTOs							National Grid forecast of those expected to transfer in 2018/19
Offshore Transmission Pass-Through (B7)	**TOFTOt**	**3B**	**NG**	**105.4**	**218.4**	**274.1**	

Appendix C: Generation Zones