nationalgrid

Final Tariff Information

Final TNUoS tariffs for 2014/15

This paper presents final Transmission Network Use of System (TNUoS) tariffs for 2014/15, which apply to generators and suppliers.

January 2014

Contents

Any Questions?

Contact:
Damian Clough

Damian.Clough@nationalgrid.com

01926 656416

1 Executive Summary

National Grid sets Transmission Network Use of System (TNUoS) tariffs for Generation and Demand annually at the end of January. The tariffs reflect the impact customers have on the cost to maintain and invest in the Transmission network. Throughout 2013, National Grid has provided updated forecasts of TNUoS tariffs including a separate forecast based on Ofgem's minded to position on CUSC Modification Proposal CMP213 (Workgroup Alternative CUSC Modification 2 (**WACM2**)).

On the 16th December 2013, Ofgem published a document titled **Project TransmiT: Update on progress and next steps**[1] which stated CMP213 will not be implemented in April 2014. Final tariffs for 2014/15 are therefore based on the current methodology.

Wider Generation and Demand tariffs, are made up of two underlying elements, which when added together make up the overall wider tariff; the Locational and Residual elements. The Locational element provides a signal to customers about the impact they have on transmission costs. The Residual element ensures that National Grid collects the total revenue allowed by Ofgem for all transmission companies based on their price controls.

Residual: Since 2013/14 there have been **5.5GW** of generation reductions notified for 2014/15 offset by **1.6GW** of generation increases, resulting in an overall reduced generation charging base. The demand charging base at Peak is forecast to reduce from 2013/14 levels due to energy efficiencies and customer behaviour.

Allowed revenues have increased for all Transmission Owners (TOs), due to network investment to aid the future connection of renewable generation and replace existing infrastructure as well as inflationary increases. This coupled with the reduction in charging bases causes the generation residual to increase by **£1.00** and demand residual to increase by **£4.64/kW**. If there is no change in the locational element of the charge as described below, charges will increase by the relevant residual element above. The increase in the residuals causes the small generators discount (Licence Condition C13) to increase to **£8.96/kW.**

Locational: The proportion of contracted Generation compared to forecast demand has decreased more in the south than seen in the north. This has generally led to northern parts of Great Britain seeing an above average increase in their generation tariffs and southern parts of GB seeing a below average decrease. Regional variations in Demand tariffs are generally less pronounced than generation, with changes in tariffs being dominated by the change in the residual element. Notable exceptions occur where large Generation or Demand changes occur on the periphery of the transmission system, which can change tariffs in those generation or demand zones more than zones located next to them.

Local Substation Tariffs and Local Circuit Tariffs which apply to Generation customers only, if all other factors stay the same, will have risen by an inflationary rate of 3.09%. Local circuit, Generation and Demand changes may have caused individual Local Tariffs to change.

[1] https://www.ofgem.gov.uk/ofgem-publications/85131/projecttransmitupdateonprogressandnextsteps.pdf

2 Tariff Summary

This section shows the Generation and Demand tariffs which will apply for 2014/15 only. For more information on how these tariffs were calculated and why they may have changed from the 2013/14 and previous forecasts, please read the rest of the document.

2.1 Generation Tariffs

Wider Tariffs (£/kW)

Zone Name		Final 2014/15
1	North Scotland	27.68
2	East Aberdeenshire	22.97
3	Western Highlands	28.35
4	Skye and Lochalsh	33.79
5	Eastern Grampian and Tayside	24.02
6	Central Grampian	21.97
7	Argyll	20.85
8	The Trossachs	18.42
9	Stirlingshire and Fife	18.02
10	South West Scotland	16.46
11	Lothian and Borders	14.18
12	Solway and Cheviot	12.73
13	North East England	9.87
14	North Lancashire and The Lakes	9.15
15	South Lancashire, Yorkshire and Humber	7.61
16	North Midlands and North Wales	6.17
17	South Lincolnshire and North Norfolk	4.65
18	Mid Wales and The Midlands	3.55
19	Anglesey and Snowdon	8.57
20	Pembrokeshire	6.55
21	South Wales	3.78
22	Cotswold	0.75
23	Central London	-3.78
24	Essex and Kent	1.43
25	Oxfordshire, Surrey and Sussex	-0.83
26	Somerset and Wessex	-2.71
27	West Devon and Cornwall	-4.70

Small Generators Discount (£/kW) = 8.96

Local Substation (£/kW)

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.176	0.100	0.072
<1320 MW	Redundancy	0.387	0.239	0.174
>=1320 MW	No redundancy	-	0.315	0.228
>=1320 MW	Redundancy	-	0.517	0.377

Local Circuit Tariff (£/kW)

Substation	14/15	Substation	14/15	Substation	14/15
Achruach	3.02	Didcot	0.22	Kilbraur	1.70
Aigas	0.57	Dinorwig	2.10	Killingholme	0.48
An Suidhe	0.00	Edinbane	5.98	Kilmorack	0.17
Arecleoch	0.27	Ewe Hill	2.27	Langage	0.58
Baglan Bay	0.57	Fallago	0.95	Lochay	0.32
Black Law	0.87	Farr Windfarm	2.05	Luichart	0.99
Bodelwyddan	-0.02	Ffestiniogg	0.22	Marchwood	0.33
Carraig Gheal	3.85	Finlarig	0.28	Mark Hill	-0.77
Carrington	0.13	Foyers	0.67	Millennium Wind	1.42
Clyde (North)	0.10	Glendoe	1.61	Mossford	3.47
Clyde (South)	0.11	Glenmoriston	1.15	Nant	2.19
Corriemoillie	2.40	Gordonbush	3.44	Quoich	3.79
Coryton	0.05	Griffin Wind	1.39	Rocksavage	0.02
Cruachan	1.67	Hadyard Hill	2.41	Saltend South	0.30
Crystal Rig	0.36	Harestanes	4.43	Spalding	0.27
Culligran	1.52	Hartlepool	0.52	Sth Humber Bank	0.74
Deanie	2.49	Hedon	0.17	Whitelee	0.09
Dersalloch	1.60	Invergarry	1.24	Whitelee Extension	0.26

Offshore Local Tariffs (£/kW)

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.404	26.758	8.294
Robin Rigg West	-0.404	26.758	8.294
Gunfleet Sands 1 & 2	15.287	14.035	2.623
Barrow	7.064	36.956	0.918
Ormonde	21.837	40.680	0.324
Walney 1	18.846	37.532	0.000
Walney 2	18.709	37.863	0.000
Sheringham Shoal	21.124	24.774	0.539
Greater Gabbard	13.260	30.469	
London Array	8.997	30.644	

2.2 Demand Tariffs

Zone No.	Zone Name.	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	16.17	2.19
2	Southern Scotland	21.24	2.95
3	Northern	26.94	3.67
4	North West	29.64	4.24
5	Yorkshire	30.25	4.11
6	N Wales & Mersey	29.72	4.20
7	East Midlands	33.10	4.58
8	Midlands	33.78	4.74
9	Eastern	34.63	4.75
10	South Wales	32.32	4.27
11	South East	37.66	5.17
12	London	38.55	5.14
13	Southern	38.79	5.38
14	South Western	38.70	5.24

3 Introduction

3.1 Background

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers (for Demand). These tariffs serve two purposes: to provide information to customers about 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 provide information about the cost of connecting in different parts of the network, National Grid determines a locationally varying component of TNUoS tariffs using a model of power flows on the transmission system. This model considers the impact that increases in generation and demand have on power flows at times of peak demand. Where a change in demand or generation increases power flows, tariffs reflect the need to maintain existing assets or invest going forward. Where either demand or generation locating in a particular area leads to lower flows on the transmission system, this benefit is also reflected in tariffs i.e. demand charges are lower in the north of Great Britain. In order to calculate likely flows on the network, information about the generation and demand connected to the network is required in conjunction with the electrical characteristics of the circuits that link these.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction (e.g. voltage and cable / overhead line) and the costs incurred in different Transmission Owner (TO) regions. Onshore, these costs are based on 'standard' conditions and are intended to be more forward looking. This means that they reflect the cost of replacing assets at current rather than historical cost so they reflect the historical 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 components of TNUoS tariffs do not recover the full revenue that onshore and offshore transmission owners have been allowed in their price controls. Therefore, to ensure the correct total revenue recovery, separate non-locational "residual" tariff elements are included in both the generation and demand tariffs. The residuals are also set to ensure that 27% of total transmission revenue is recovered from generators, and 73% from demand. This ratio is fixed in the charging methodology.

The main 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 local charges are therefore locational and specific to individual generators.

4 Updates to the Charging Model for 2014/15

In order to calculate generation and demand tariffs for 2014/15 a number of changes must be made to the model which was used to calculate tariffs for 2013/14.

The charging methodology which can be found in section 14 of the CUSC[2] dictates what information should be used to set tariffs; the sources of information; and when the information becomes fixed. The forecasts of tariffs for 2014/15 have changed throughout the year as these information sources were updated.

The inputs fall into the following categories:

- generation, demand, and the transmission network, which affect the locational element of tariffs;
- the total revenue to collect and the charging bases, which affect the residual element of tariffs; and
- various model parameters, such as unit investment costs

As 2014/15 is the second year of the price control, generation zone boundaries, expansion factors and network security factors remain fixed. These are normally only changed at the start of price controls.

4.1 Changes to inputs throughout 2013/14

The table below shows how the various inputs to the model have changed throughout the year.

	2013/14	Initial View	April Quarterly Update	July Quarterly Update	November Quarterly Update	Draft Tariffs	Final Tariffs
Generation (GW)	82084	88318	82383	80045	79731	78200	78200
Source	Contracted Generation 31st Oct 2012	Contracted Generation 31st Oct 2012	Contracted Generation 1st April 2013	Contracted Generation 8th July 2013	Contracted Generation 1st Oct 2013	Contracted Generation 31st Oct 2013	Contracted Generation 31st Oct 2013
Demand (GW)	60216	61299	61299	56578	56574	56617	56617
Source				Updated DNO Forecasts and Embedded Generation	Updated Embedded	Updated Embedded	
Circuit	2012/13 View	2012/13 View	2012/13 View	2012/13 View	2013/14 View	2013/14 View	2013/14 View
TNUoS Revenue (£m)	2153.2	2433	2433	2430.9	2498	2451.9	2477.3
Gen Base	75.141	81.252	75.549	73.989	73.684	73.367	73.031
Demand Bases	Peak Demand 56, HH 16.1, NHH 28.6TWh	Peak Demand 56, HH 16.1, NHH 28.6TWh	Peak Demand 56, HH 16.1, NHH 28.6TWh	Peak Demand 56, HH 16.1, NHH 28.6TWh	Peak Demand 56, HH 16.1, NHH 28.6TWh	Reduction of Peak demand to 55.3 and HH to 15.9. NHH 28.6TWh	Peak demand 55.3 and HH 15.9. NHH 28.6TWh

The Quarterly Updates can be found at the following link.

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

[2] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/The-CUSC/

4.2 Changes influencing the locational element of tariffs

4.2.1 Generation

Information about generation capacities for 2014/15 has been updated using the contracted background as of 31 October 2013. The generation used in the model is that which is contracted to be available at peak demand in 2014/15. There has been a net decrease in modelled generation of 3.9GW between 2013/14 and 2014/15. This is comprised of TEC increases totalling 1.6GW offset by 5.5GW of TEC reductions.

Contracted generation has reduced throughout the year from that which was forecasted at our Initial view of tariffs in January. National Grid uses the contracted generation background at the time of the forecast.

Appendix A lists the changes to the contracted generation that have occurred since tariffs were set in 2013/14.

4.2.2 Demand

Information for the 2014/15 peak demand at each Grid Supply Point (GSP) has been sourced from information received from the Distribution Network Operators (DNOs) (the "Week 24" submissions made under the Grid Code) and directly connected demand sites such as steelworks and other heavy industry. This is used to determine power flows on the network at peak and so contributes to the locational element of the charges (the difference between zonal charges).

The updated information shows a decrease in peak demand[3] between 2013/14 and 2014/15 of about 3.6GW. The volume and location of demand determines the quantity of generation required to satisfy demand and subsequent power flows on the Transmission network. If demand reduces in an area of the network without a subsequent decrease in nearby generation then this may increase generation tariffs in the locality with an opposite effect on local demand tariffs.

Compared to 2013/14, forecast peak demand for 2014/15 has dropped significantly across the majority of DNO's in England and Wales, whereas forecast peak demand in Scotland remains fairly static or has slightly increased. The drop in peak demand reflects work done by the DNO's over the past year to analyse outturn demand and the real effect of embedded generation at peak within their networks. Although there is a step change in demand forecasts, these forecasts are consistent with actual peak demands and future forecasts being received this year, and so are not considered a one off anomaly. Appendix B provides the zonal demand information.

4.2.3 Transmission network

A number of network changes have to be implemented in order to connect new generation and accommodate changes in power flows on the network. The network information takes into account the existing network and planned investments for 2014/15, which have been provided by each TO for its respective network.

[3] The demand used for the peak is the net transmission demand i.e. actual demand less exemptible generation.

Following the implementation of CMP203[4] (TNUoS Charging Arrangements for Infrastructure Assets Subject to One-Off Charges) the following adjustments have been made:

Circuit	Adjustment
East Kilbride South – Whitelee	Cable amended to OHL
East Kilbride South –Whitelee Extension	Cable amended to OHL
Elvanfoot – Clyde North	Cable amended to OHL
Elvanfoot – Clyde South	Cable amended to OHL
Wishaw - Blacklaw	Cable amended to OHL

The purpose of these adjustments is to reflect the fact that certain customers have paid an additional one-off charge in relation to the circuits indentified above, which are also subject to ongoing TNUoS charges.

4.3 Changes to ensure the correct revenue recovery

4.3.1 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. This means that each TO's revenue is set at the price review, but then adjusted during the price control period depending on its performance against incentives, its innovation and the volume of connections and transmission capacity it delivers. Connections and capacity are driven by customer activity.

Onshore TOs may also receive revenue under the Transmission Investment for Renewable Generation incentive (TIRG). This incentive is set by Ofgem to fund specific infrastructure projects required to connect renewable generation.

Under previous price controls, the revenue adjustments, together with corrections for under/over recovery, were lagged by one year. This required each TO to forecast its performance and revenues within year, to set TNUoS tariffs for the following year. Errors in these forecasts could then lead to under/over recovery in the following year. The RIIO price control generally lags adjustments by two years. This allows performance and revenues in a particular year to be accurately accounted for in the following year and the corresponding revenue adjustments incorporated into tariffs the year after that.

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 are relatively predictable, the revenue for new OFTOs has to be forecast.

[4] CMP203 amended circuit information where a one-off charge has been paid by a user.

The table on the following page shows the final revenue forecast for 2013/14 upon which tariffs for 2013/14 were set. It also shows the Final revenue forecast for 2014/15 and how this has changed since the initial view in January 2013.

	2013/14 TNUoS Revenue	2014/15 TNUoS Revenue					
£m Nominal	**Jan 2013 Final**	Jan 2013 Initial View	April 2013 Update	July 2013 Update	Nov 2013 Update	Dec 2013 Draft	**Jan 2014 Final**
National Grid	**1,587.3**	1,749.5	1,749.5	1,770.9	1,767.5	1,762.4	**1,761.9**
Scottish Power	**271.3**	293.0	293.0	313.5	320.8	311.6	**312.2**
Scottish Hydro Electricity	**172.5**	185.0	185.0	163.1	215.0	203.6	**214.0**
Offshore	**165.5**	232.3	232.3	211.0	206.3	200.2	**218.4**
Network Innovation Competition	**-**	13.5	13.5	15.7	32.5	18.0	**17.8**
Maximum Revenue	**2,196.6**	2,473.3	2,473.3	2,474.2	2,542.1	2,495.8	**2,524.3**
Pre-vesting connections	**43.3**	40.0	40.0	43.3	44.1	43.9	**47.0**
TNUoS	**2,153.3**	2,433.3	2,433.3	2,430.9	2,498.0	2,451.9	**2,477.3**
Maximum Revenue	**2,196.6**	2,473.3	2,473.3	2,474.2	2,542.1	2,495.8	**2,524.3**

Overall revenues have increased by 14.9% on 2013/14. This includes the effect of inflation (3.6%). A large proportion of this is due to year-on-year increases in allowed revenue for onshore TOs. The eight year RIIO price controls determined by Ofgem at the end of 2012 have larger increases in the early years to fund network investment. Revenue increases in Scotland are proportionally higher due to TIRG revenues.

Onshore TO revenue forecasts have generally increased over the year as onshore TOs have re-forecasted their allowed revenues under the RIIO price control and TIRG incentives. Recent changes have incorporated directions by Ofgem to reflect past performance.

Offshore Transmission Owners (OFTOs) revenues are forecast to rise due to inflationary increases in existing OFTO revenue and new OFTOs due to be appointed in 2014/15. 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 and Thanet; and more recently West of Duddon Sands has been included leading to an increase in OFTO revenue.

Ofgem can award up to £27m (2009/10 prices) per year for innovation projects under the Network Innovation Competition Fund. National Grid collects the revenue for this fund on behalf of the successful bidders. At the end of 2013 Ofgem awarded funding worth £17.8m in 2014/15.

Revenues are recovered through TNUoS charges and ongoing connection charges for assets already installed when the industry was privatised (Pre-vesting connections). Pre-vesting connection income of £47.0m has been calculated for 2014/15 and deducted to leave the revenue to be recovered from TNUoS charges.

4.3.2 Charging bases for 2014/15

The previously discussed figures in the model used to set locational signals are based on objectively published information e.g. the contracted generation for peak as at 31 October 2013. However, in order to ensure correct revenue recovery National Grid has to take a view on the actual generation and demand that will incur charges in the following year. This section discusses the volumes of demand and generation that National Grid has forecast to pay charges in 2014/15. The table below shows the various charging bases and how they have changed from the previous year.

CHARGING BASE	CHARGING YEAR 2013/14	2014/15	CHANGE
GENERATION (GW)	75.1	73	-2.1
DEMAND			
PEAK (GW)	56	55.3	-0.7
HH (GW)	16.1	15.9	-0.2
NHH (TWh)	28.6	28.6	0

Generation

The generation charging base for 2014/15 has been updated using the final contracted background for 2014/15. The chargeable generation for 2014/15 is 73GW which is 93.4% of the final contracted position for 2014/15. The reduction occurs due to adjustments for interconnector capacity discussed below; expected delays in the completion of new power stations; and generation located in negative tariff zones not generating up their contracted transmission entry capacity (TEC). As the contracted background cannot be adjusted any possible delays in the completion of new power stations can only be taken into account in the generation charging base thus affecting the residual element of the generation charge.

Demand

The demand charging base and the split between HH and NHH demand have been reviewed. We have assumed a peak system demand of 55.3GW. This is a reduction on the previous year from 56GW, and is line with forecasts in the 2013 Electricity Ten Year Statement (E-TYS) and actual metering data. Our view of half-hourly demand at Triad has also decreased to 15.9GW. Non Half Hourly Energy consumption is forecasted to remain at 28.6TW (sum of daily demand between 4pm and 7pm).

Adjustments for Interconnectors

When determining the power flows on the transmission system at peak demand, the interconnectors are included within the charging model. However, since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases. Therefore, when calculating the generation charging base from the contracted TEC background, the following reductions are needed to reflect the charging treatment of interconnectors.

Interconnector	Zone	Adjustment to charging base (MW)
French Interconnector	24	1988
Britned	24	1200
East-West	16	500
Moyle	10	80

The revenues associated with the impact of flows by interconnectors is dealt with through the Inter-TSO Compensation fund (ITC) established under the European Electricity Regulation and reflected directly in National Grid's transmission licence as a pass-through revenue item.

4.4 Changes to Model parameters

There are a number of parameters in the charging model that are fixed during a price control period to provide stability for customers. These include generation zone boundaries, the expansion factors, and the network security coefficient. 2014/15 is the second year of the current price control so these remain the same as for 2013/14.

4.4.1 The cost of network investments

The charging model contains information about the unit cost of investing in the transmission network, specifically the expansion constant and expansion factors. The expansion constant represents the cost of transporting 1MW over 1km of 400kV overhead line (OHL). During a price control period this number is only changed by RPI (May to October average). The expansion constant is inflated from £12.514404/MWkm in 2013/14 to £12.901218/MWkm in 2014/15. Expansion Factors as can be found in the latest charging statement are fixed for the price control therefore remain unchanged from 2013/14.

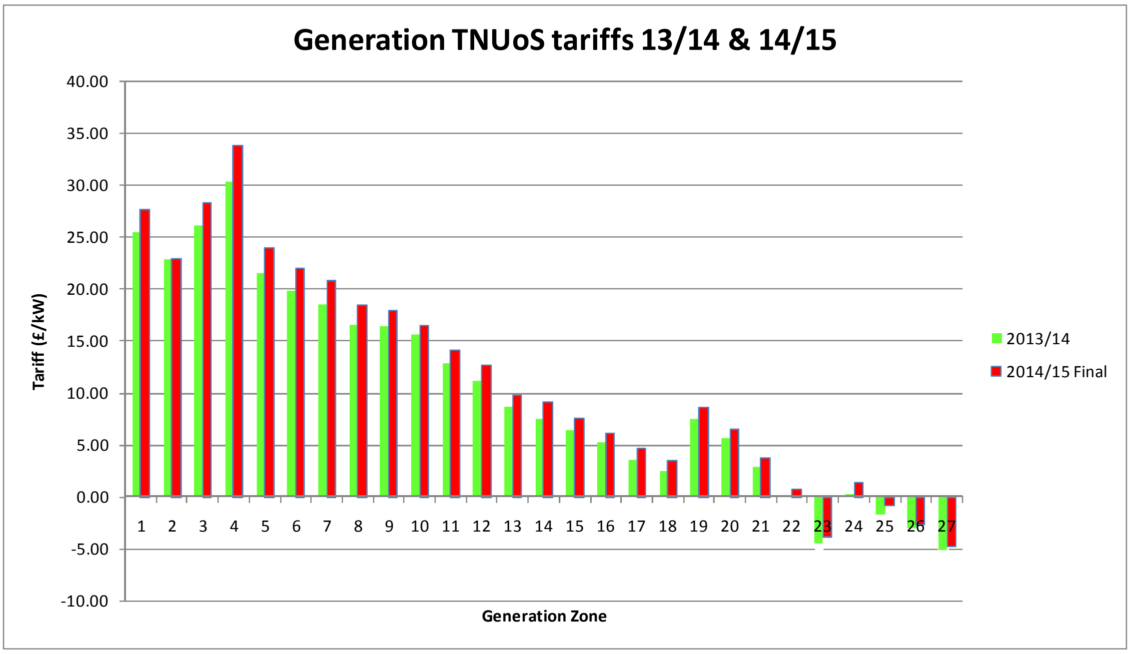
5 Final generation tariffs for 2014/15

Based on the changes outlined in this report, the following section provides details of the wider and local generation tariffs for 2014/15.

5.1 Wider zonal generation tariffs

The following table shows the generation zonal TNUoS tariffs in (£/kW) and how they have changed from the previous year and draft tariffs produced in December. The chart below that shows the same information in graphical form.

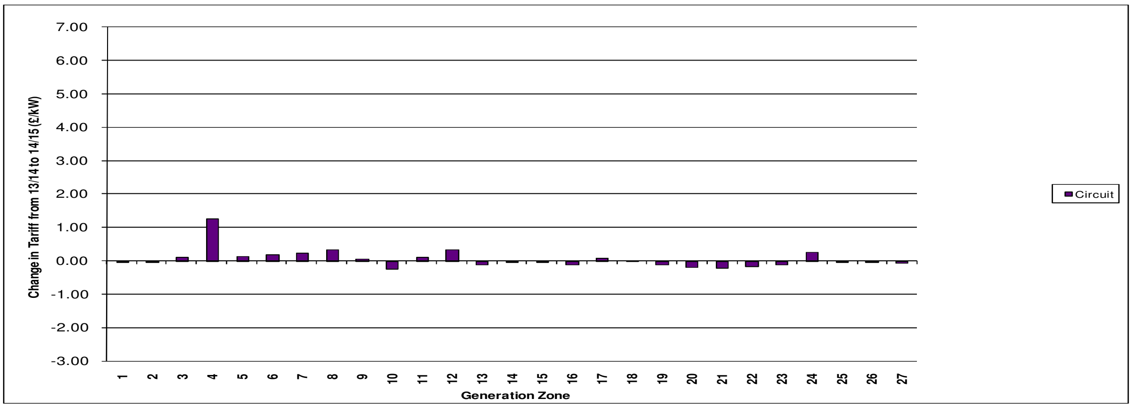
Zone Name		2013/14	Final 2014/15	Change compared to…	
				2013/14	Draft 14/15
1	North Scotland	25.42	27.68	2.26	0.06
2	East Aberdeenshire	22.8	22.97	0.17	0.06
3	Western Highlands	26.15	28.35	2.20	0.06
4	Skye and Lochalsh	30.25	33.79	3.54	0.06
5	Eastern Grampian and Tayside	21.55	24.02	2.47	0.06
6	Central Grampian	19.75	21.97	2.22	0.06
7	Argyll	18.52	20.85	2.33	0.06
8	The Trossachs	16.49	18.42	1.93	0.06
9	Stirlingshire and Fife	16.4	18.02	1.62	0.06
10	South West Scotland	15.53	16.46	0.93	0.06
11	Lothian and Borders	12.84	14.18	1.34	0.06
12	Solway and Cheviot	11.07	12.73	1.66	0.06
13	North East England	8.64	9.87	1.23	0.06
14	North Lancashire and The Lakes	7.48	9.15	1.67	0.06
15	South Lancashire, Yorkshire and Humbe	6.34	7.61	1.27	0.06
16	North Midlands and North Wales	5.18	6.17	0.99	0.06
17	South Lincolnshire and North Norfolk	3.49	4.65	1.16	0.06
18	Mid Wales and The Midlands	2.44	3.55	1.11	0.06
19	Anglesey and Snowdon	7.41	8.57	1.16	0.06
20	Pembrokeshire	5.57	6.55	0.98	0.06
21	South Wales	2.92	3.78	0.86	0.06
22	Cotswold	0.04	0.75	0.71	0.06
23	Central London	-4.44	-3.78	0.66	0.06
24	Essex and Kent	0.19	1.43	1.24	0.06
25	Oxfordshire, Surrey and Sussex	-1.69	-0.83	0.86	0.06
26	Somerset and Wessex	-3.05	-2.71	0.34	0.06
27	West Devon and Cornwall	-5.17	-4.70	0.47	0.06



The following section highlights the impacts on locational tariffs when the inputs previously described in section 4 are made to the 13/14 model independently, with the changes subsequently added to each other.

Circuit Changes

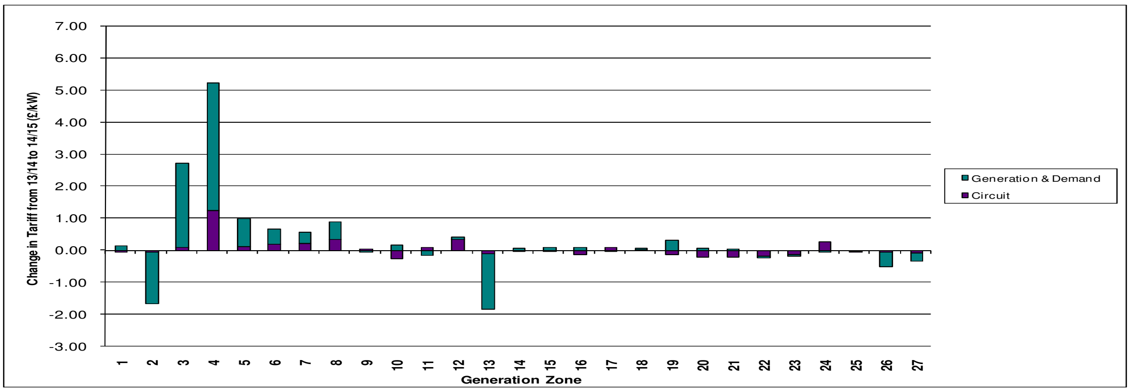
Ordinarily circuit changes have limited effect on charges. Where the change affects a Generator spur or changes flows along circuits then this can affect tariffs.



Generation & Demand

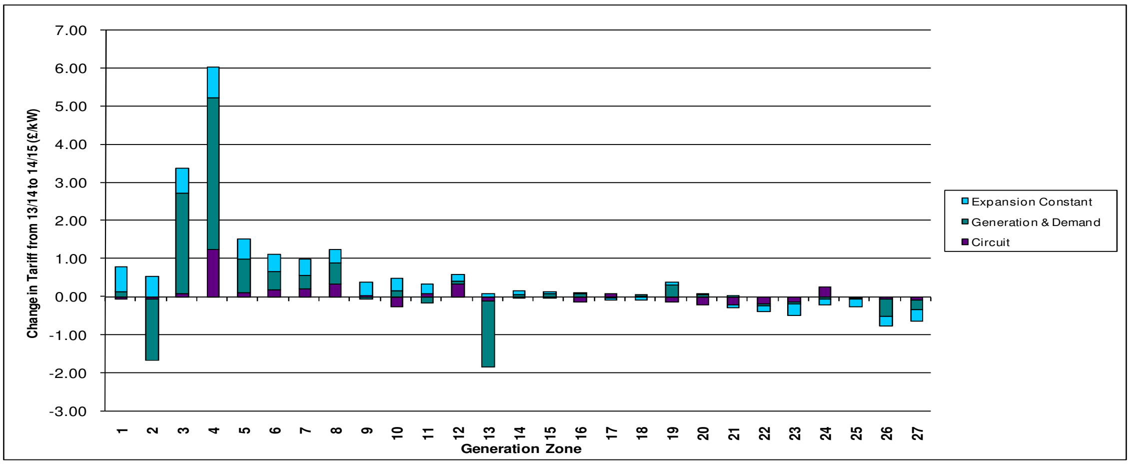
The largest driver behind locational tariff changes in the model are generation and demand changes but particularly contracted generation changes (see Appendix A and B). Noticeable changes are discussed in more detail below;

- Peterhead TEC reduction of 780MW drops locational charges in **Zone 2**
- In **Zone 4** (in which there is one generator) and, to a lesser extent in **Zone 3**, the increase in the tariff has been caused by power flows reversing direction on a long radial spur. The increase in the current embedded generation forecast in this area has resulted in more circuits exporting thus increasing the tariff.
- **Zone 13** sees a reduction due to demand changes in the area and generation changes to the North
- Where there are no specific TEC reductions, coupled with demand remaining fairly stable, power flows from the north to south have increased pushing generation tariffs up as seen in most zones in Scotland, with the opposite affect in the South



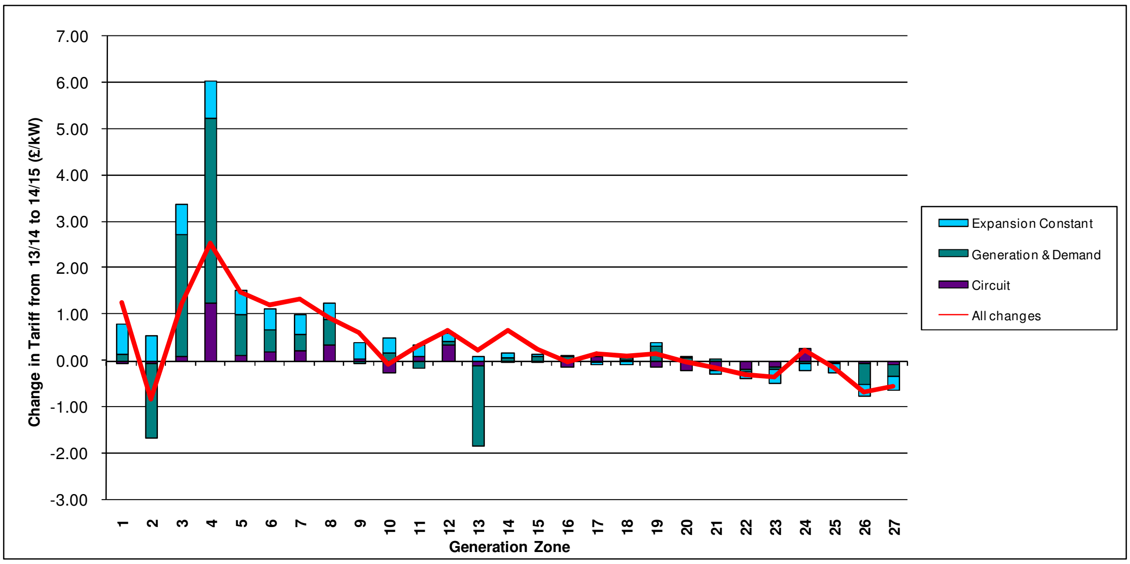
Expansion Constant

The Expansion Constant has increased from the previous year due to RPI. The locational tariffs represent the effect on flows on the system in terms of distance (MWkm). The Expansion Constant works out the average cost of that distance per km. Therefore those Generation Zones which have a larger affect on flows on the system are affected more by the Expansion Constant increasing.



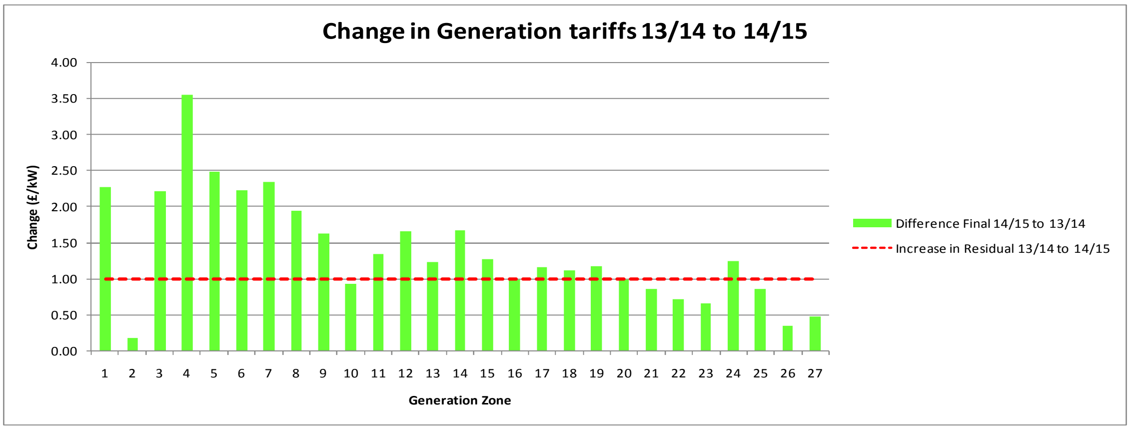
All Changes

Changes to locational prices are a combination of all inputs. The graph below shows the final change in locational prices when all inputs to the model are made at the same time. When all inputs are combined together, they can sometimes counter each other, as seen in zone 13 or exaggerate the individual changes i.e. zone 14, so although a particular input can often be pinpointed to explain a change in tariffs sometimes it is a combination of various inputs that result in the change.



Impact on Wider Tariffs (Locational + Residual)

The charts on the previous page show the effect various inputs have on locational charges. The chart below shows the changes in tariffs between Final 14/15 tariffs (Green Bars) and 13/14 tariffs. The red line highlights the increase in the residual. Changes above or below this line are caused by the inputs mentioned earlier in this section.



Summary explanation of changes in tariffs between Final 14/15 and 13/14

Generation tariffs have risen on average by £1.01/kW[5] due to a rise in the residual resulting from an increase in allowed revenues and a reduction in the charging base. The mix of generation to demand as a result of demand and generation changes results in an increase in North to South flows. Where there are no significant changes in capacity or demand this results in an increase in tariffs in the North and Midlands with a resulting decrease in tariffs in the South. This change is exaggerated by the increase in the Expansion Constant.

[5] Total Revenue collected from Wider Generation charges divided by generation base

Detailed explanation of changes

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the forecast tariff changes:

- ❑ The generation **residual element**, which ensures the correct total revenue is recovered from generation, has increased by £1.00/kW to £5.81/kW. The increase is due to a reduction in the charging base and an increase in allowed revenues, as shown in the table on the following page.

Item (£m, unless stated)		**13/14**	**14/15**	**Δ**
Revenue recoverable through TNUoS	*A*	2,153	2,477	324
Revenue to collect from generation	*B = 0.27 x A*	581	669	88
Revenue from zonal tariffs	*C*	55	54	-1
Revenue from onshore local tariffs	*D*	34	31	-3
Revenue from offshore local tariffs	*E*	131	160	29
Revenue to recover from residual	*F = B-C-D-E*	361	424	63
Generation charging base (GW)	*G*	75.1	73.0	-2.1
Residual (£/kW)	*F / G*	**4.81**	**5.81**	**1.00**

- ❑ In **Zone 4** (in which there is one generator) and, to a lesser extent in **Zone 3**, the increase in the tariff has been caused by power flows reversing direction on a long radial spur. The increase in the current embedded generation forecast in this area has resulted in more circuits exporting thus increasing the tariff.

- ❑ **Zone 2** sees a reduction in tariffs due to the reduction in Capacity at Peterhead (780MW) the major generator in the area

- ❑ the generation tariff in **Zone 24** has increased in relation to the zones around it due to rewiring work around London which affects flows

Summary explanation of changes in tariffs between Draft tariffs for 14/15 and Final tariffs for 14/15

There have been no changes to inputs into the model which affect the locational element of the tariff since Draft tariffs were published before Christmas. Any changes to tariffs result from an increase in allowed revenues and reduction in the generation charging base.

Detailed explanation of changes

Whilst the above is a high-level summary of the changes, the following provides a more detailed explanation of the forecast tariff changes:

- The generation **residual element**, which ensures the correct total revenue is recovered from generation, has increased by £0.05/kW to £5.81/kW. The increase is due to a slight increase in allowed revenues and reduction in the generation charging base due to further information

Item (£m, unless stated)		**Draft**	**Final**	**Δ**
Revenue recoverable through TNUoS	*A*	2,452	2,477	25
Revenue to collect from generation	*B = 0.27 x A*	662	669	7
Revenue from zonal tariffs	*C*	54	54	0
Revenue from onshore local tariffs	*D*	31	31	0
Revenue from offshore local tariffs	*E*	154	160	6
Revenue to recover from residual	*F = B-C-D-E*	423	424	1
Generation charging base (GW)	*G*	73.4	73.0	-0.4
Residual (£/kW)	*F / G*	**5.76**	**5.81**	**0.05**

5.2 Onshore local circuit tariffs

In addition to changes in the wider zonal generation charges, there have been changes in the local circuit charges that onshore generators not connected to the MITS are liable to pay. Local circuit tariffs may have changed from their level in 2013/14 for several reasons, these include:

- changes to flows on the local circuits (“Flows”);
- circuit changes
- Expansion Constant (for local Circuits with long lengths of circuit the effect will be greater)

The table below presents the local circuit tariffs for 2014/15 (£/kW), the changes in (£/kW) since 2013/14, and the main driver for the changes where these are most significant.

Substation	**13/14**	**14/15**	**Change**	**Reason for Change**
Achruach	-	3.02	-	New
Aigas	0.53	0.57	0.04	
An Suidhe	1.17	0.00	-1.17	Flows
Arecleoch	0.07	0.27	0.20	Circuit
Baglan Bay	0.55	0.57	0.02	
Black Law	0.85	0.87	0.02	
Bodelwyddan	-0.02	-0.02	0.00	
Carraig Gheal	3.73	3.85	0.12	Expansion Constant
Carrington	-	0.13	-	New
Clyde (North)	0.09	0.10	0.01	
Clyde (South)	0.11	0.11	0.00	
Corriemoillie	2.83	2.40	-0.43	Flows
Coryton	0.29	0.05	-0.24	Flows

Substation	13/14	14/15	Change	Reason for Change
Cruachan	1.52	1.67	0.15	Circuit
Crystal Rig	0.35	0.36	0.01	
Culligran	1.47	1.52	0.05	
Deanie	2.41	2.49	0.08	
Dersalloch	1.55	1.60	0.05	
Didcot	0.22	0.22	0.00	
Dinorwig	2.04	2.10	0.06	
Edinbane	5.81	5.98	0.17	Expansion Constant
Ewe Hill	2.35	2.27	-0.08	
Fallago	0.92	0.95	0.03	
Farr Windfarm	1.9	2.05	0.15	Expansion Constant
Ffestiniogg	0.21	0.22	0.01	
Finlarig	0.27	0.28	0.01	
Foyers	0.65	0.67	0.02	
Glendoe	1.56	1.61	0.05	
Glenmoriston	1.12	1.15	0.03	
Gordonbush	3.47	3.44	-0.03	
Griffin Wind	2.72	1.39	-1.33	Circuit
Hadyard Hill	2.46	2.41	-0.05	
Harestanes	4.3	4.43	0.13	Expansion Constant
Hartlepool	0.5	0.52	0.02	
Hedon	0.15	0.17	0.02	
Invergarry	-0.58	1.24	1.82	Flows
Kilbraur	1.72	1.70	-0.02	
Killingholme	0.46	0.48	0.02	
Kilmorack	0.15	0.17	0.02	
Langage	0.56	0.58	0.02	
Lochay	0.31	0.32	0.01	
Luichart	0.96	0.99	0.03	
Marchwood	0.32	0.33	0.01	
Mark Hill	-0.74	-0.77	-0.03	
Millennium Wind	1.38	1.42	0.04	
Mossford	3.17	3.47	0.30	Flows
Nant	-1.04	2.19	3.23	Flows
Quoich	1.68	3.79	2.11	Flows + Circuit
Rocksavage	0.01	0.02	0.01	
Saltend South	0.29	0.30	0.01	
Spalding	0.26	0.27	0.01	
Sth Humber Bank	0.71	0.74	0.03	
Whitelee	0.09	0.09	0.00	
Whitelee Extension	0.25	0.26	0.01	

5.3 Onshore local substation tariffs

All transmission connected generation is liable to pay a local substation charge. The following table shows the 2014/15 onshore local substation tariffs that apply to all transmission connected generators where the first transmission substation is onshore. The substation tariffs have been updated from 2013/14 by RPI. The tariff in £/kW depends on the substation rating, connection type, and connection voltage of the substation. TEC changes have resulted in some substations ratings changing from 2013/14 levels. If you are unsure which Local Substation Tariff may apply to you, please contact National Grid.

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.176	0.100	0.072
<1320 MW	Redundancy	0.387	0.239	0.174
>=1320 MW	No redundancy	-	0.315	0.228
>=1320 MW	Redundancy	-	0.517	0.377

5.4 Offshore local tariffs

Offshore local circuit and substation tariffs apply to generators connected to an offshore transmission network. In addition, where an offshore transmission network connects to an onshore distribution network, an Embedded Transmission Use of System (ETUoS) tariff is applicable. This is in addition to any ongoing distribution use of system changes that are passed through to the offshore generator on a monthly basis.

National Grid has updated these tariffs by inflation. The table below shows the local offshore tariffs for existing offshore generators.

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.404	26.758	8.294
Robin Rigg West	-0.404	26.758	8.294
Gunfleet Sands 1 & 2	15.287	14.035	2.623
Barrow	7.064	36.956	0.918
Ormonde	21.837	40.680	0.324
Walney 1	18.846	37.532	0.000
Walney 2	18.709	37.863	0.000
Sheringham Shoal	21.124	24.774	0.539
Greater Gabbard	13.260	30.469	
London Array	8.997	30.644	

In those cases where an OFTO has yet to be appointed, National Grid has sought information from the Preferred Bidders (or developers) of offshore transmission projects. Where information has been provided, this has been on a confidential basis to enable onshore tariffs to be calculated and to provide illustrative tariffs to relevant offshore generators. National Grid expects to publish these tariffs once the OFTO has been appointed.

5.5 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals, is forecast to increase from £7.55/kW to **£8.96/kW.**

6 Final demand tariffs for 2014/15

The following tables show the forecast changes to half-hourly (HH) and non half-hourly (NHH) demand tariffs from 2013/14 and Draft tariffs for 2014/15

Half-hourly demand tariffs (£/kW)

Zone Name		2013/14	Final 2014/15	Change compared to… 2013/14	Draft 14/15
1	Northern Scotland	11.05	16.17	5.12	0.33
2	Southern Scotland	16.79	21.24	4.45	0.33
3	Northern	22.35	26.94	4.59	0.33
4	North West	25.18	29.64	4.46	0.33
5	Yorkshire	25.49	30.25	4.76	0.33
6	N Wales & Mersey	25.63	29.72	4.09	0.33
7	East Midlands	28.21	33.10	4.89	0.33
8	Midlands	29.20	33.78	4.58	0.33
9	Eastern	29.89	34.63	4.74	0.33
10	South Wales	27.54	32.32	4.78	0.33
11	South East	32.83	37.66	4.83	0.33
12	London	34.08	38.55	4.47	0.33
13	Southern	33.75	38.79	5.04	0.33
14	South Western	33.55	38.70	5.15	0.33

Non half-hourly demand tariffs (p/kWh)

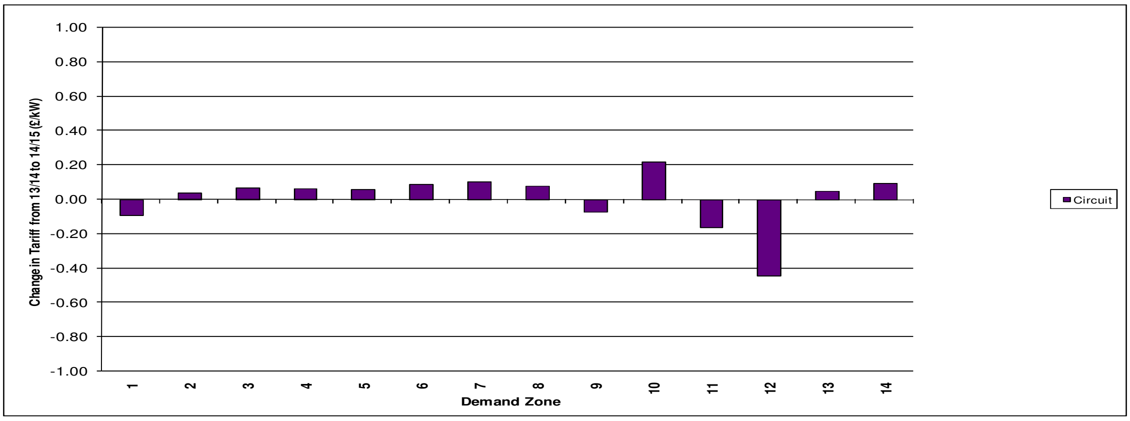
Zone Name		2013/14	Final 2014/15	Change compared to… 2013/14	Draft 14/15
1	Northern Scotland	1.52	2.19	0.67	0.04
2	Southern Scotland	2.36	2.95	0.59	0.05
3	Northern	3.08	3.67	0.59	0.04
4	North West	3.65	4.24	0.59	0.05
5	Yorkshire	3.51	4.11	0.60	0.04
6	N Wales & Mersey	3.67	4.20	0.53	0.05
7	East Midlands	3.96	4.58	0.62	0.05
8	Midlands	4.15	4.74	0.59	0.05
9	Eastern	4.15	4.75	0.60	0.05
10	South Wales	3.69	4.27	0.58	0.04
11	South East	4.56	5.17	0.61	0.05
12	London	4.60	5.14	0.54	0.04
13	Southern	4.74	5.38	0.64	0.05
14	South Western	4.60	5.24	0.64	0.04

Inputs into the model

As already discussed in section 4 a number of inputs are made to the model throughout the year. The effect on the locational element of demand tariffs is the opposite of generation tariffs. However as demand zones cover larger and different areas to the generation zones these changes tend to be more smoothed out when compared to generation changes.

Circuit Changes

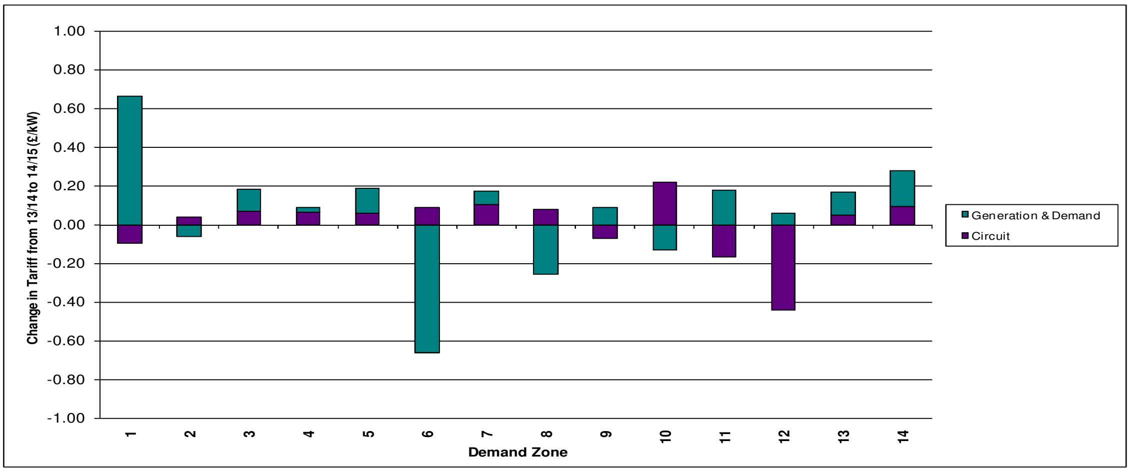
Ordinarily circuit changes have limited affect on charges. Where the change affects a Generator spur or changes flows along circuits then this can affect tariffs. The change in zone 12 reflects rewiring work around London



Generation & Demand

The largest driver behind locational tariff changes in the model is Generation & Demand changes but particularly Generation changes. Appendix A and B shows how Generation and Demand has changed throughout the year. Appendix A shows the difference between contracted generation in 2013/14 and 2014/15, whereas Appendix B shows demand changes. Noticeable changes on the graph are discussed in more detail below;

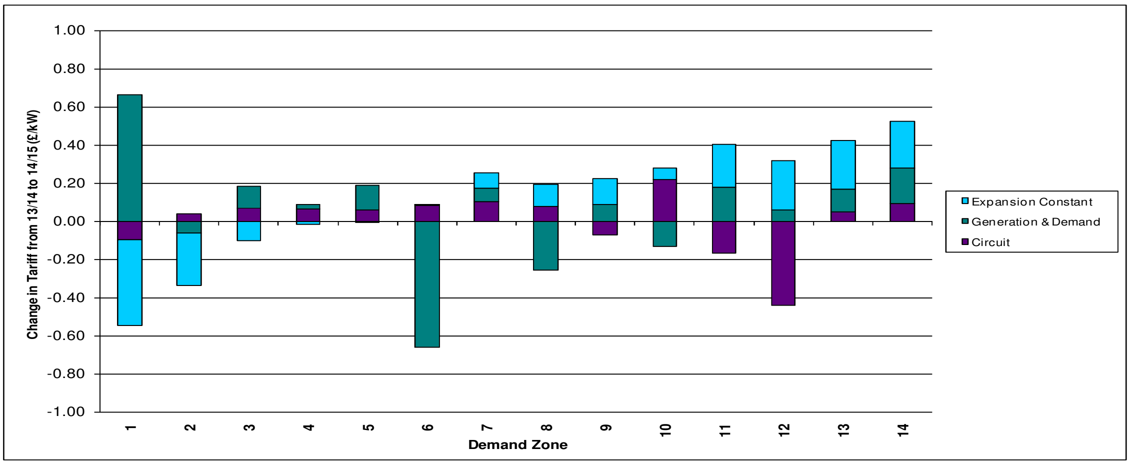
- Peterhead TEC reduction of 780MW increases locational charges in **Zone 1**
- Forecast demand Zone 6 reduced by more than the average due to DNO's forecasts of embedded generation in the demand zone.



Expansion Constant

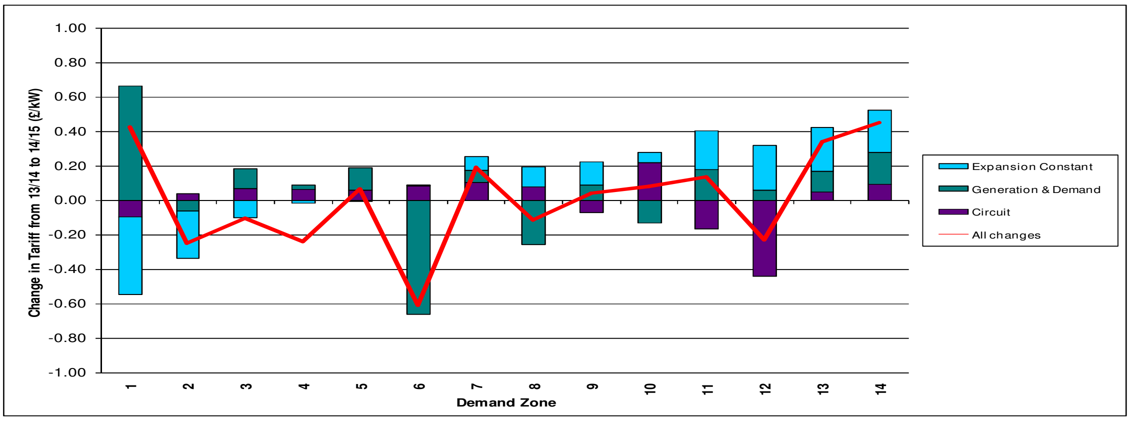
The Expansion Constant has increased from the previous year due to RPI. The locational tariffs represent the effect on flows on the system in terms of distance (MWkm). The Expansion

Constant works out the average cost of that distance per km. As mentioned before those Generation Zones which have a larger affect on flows on the system are affected more by the Expansion Constant increasing. The reverse happens with demand zones.

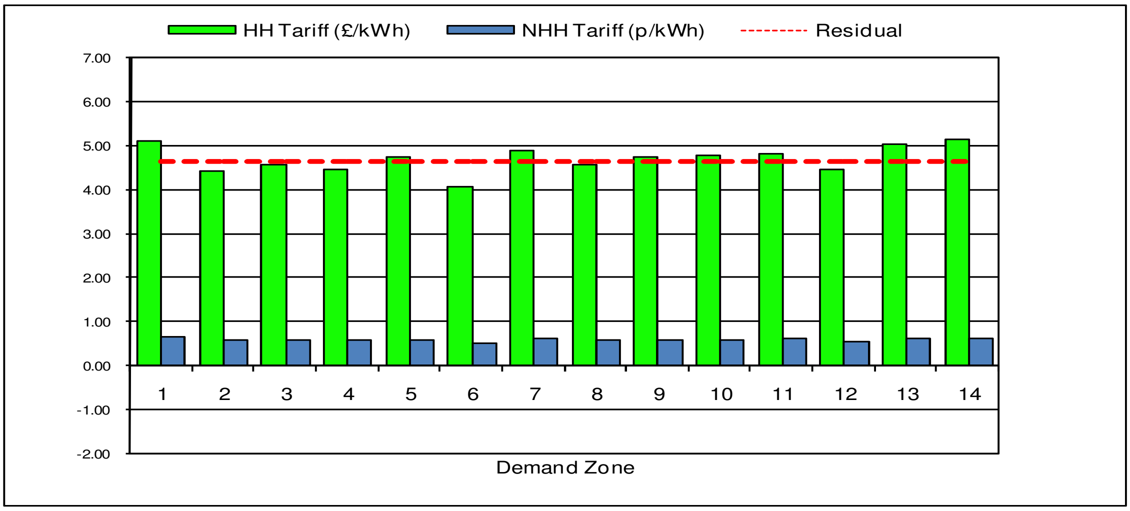


All Changes

Changes to locational prices are a combination of all inputs. The graph below shows the final change in locational prices. When all inputs are combined together, they can sometimes counter each other, exaggerate the individual changes or one input may be the dominant driver.



The chart below shows the changes in tariffs between Final 14/15 tariffs and 13/14 tariffs. The red line highlights the increase in the residual which affects HH tariffs. Changes above or below this line are caused by the inputs mentioned earlier in this section.



Summary explanation of changes in tariffs between Final 14/15 and 13/14

Forecast demand tariffs are expected to increase in all zones and on average[6] by £4.70/kW. This is because recovery is forecast to increase. The reduction in demand and generation is fairly evenly spread across the demand zones resulting in minimal change other than the residual. Where generation drops greater than demand, tariffs increase such as Zone 1, and where demand drops greater than generation, tariffs decrease such as Zone 6.

Detailed explanation of changes compared to 2013/14

A more detailed explanation of the main changes in demand tariffs follows:

- The **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures correct revenue recovery, has increased by £4.64/kW to £30.05/kW. This reflects the expected increase in the total allowed revenue, and drop in the charging base.

Item (£m, unless stated)		**13/14**	**14/15**	**Δ**
Revenue recoverable through TNUoS	*A*	2,153	2,477	324
Revenue to collect from demand	*B = 0.73 x A*	1,572	1,808	236
Revenue from zonal charges	*C*	149	147	-2
Revenue from residual	*D = B - C*	1,423	1,661	238
Charging Base (GW)	*E*	56	55.3	-0.7
Residual (£/kW)	*D / E*	**25.41**	**30.05**	**4.64**

- the increases in **Zone 1** is mainly driven by the TEC reduction at Peterhead (780MW)

[6] Weighted average based on peak demand in each zone.

- **Zone 6** forecast peak demand has dropped above average which can be seen in appendix B

- **Zone 12** sees a decrease due to rewiring work

As the forecast proportion of HH and NHH demand in each zone has remained constant, the trend in NHH tariffs mirrors that of HH tariffs.

Summary explanation of changes in tariffs between Draft tariffs for 14/15 and Final tariffs for 14/15

Inputs to the model which sets locational prices were fixed for the year when setting draft tariffs. Therefore any changes to tariffs since draft tariffs were published are due to a change in allowed revenues.

Detailed explanation of changes compared to Draft Tariffs

A more detailed explanation of the main changes in demand tariffs follows:

- The **residual tariff** element of HH demand tariffs, which is the same in each zone and ensures correct revenue recovery, has increased by £0.35/kW to £30.05/kW. This reflects the expected increase in the total allowed revenue and the decrease in the charging base.

Item (£m, unless stated)		**Draft**	**Final**	**Δ**
Revenue recoverable through TNUoS	*A*	2,452	2,477	25
Revenue to collect from demand	*B = 0.73 x A*	1,790	1,808	18
Revenue from zonal charges	*C*	147	147	-
Revenue from residual	*D = B - C*	1,643	1,661	18
Charging Base (GW)	*E*	55.3	55.3	-
Residual (£/kW)	*D / E*	**29.70**	**30.05**	**0.35**

As the forecast proportion of HH and NHH demand in each zone has remained constant, the trend in NHH tariffs mirrors that of HH tariffs.

7 Comments & Feedback

Comments & Feedback

National Grid welcomes comments and feedback on the information contained in this report. 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
Damian.Cough@nationalgrid.com
National Grid
Warwick Technology Park
Warwick
CV34 6DA

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

8 Appendices

Appendix A Generation changes for 2014/15

Appendix B Zonal generation and demand changes for 2014/15

Appendix C Generator to zone mapping tables

Appendix A: Generation changes for 2014/15

Please note Contracted Modelled Generation has not changed between Draft and Final tariffs for 2014/15

TEC REGISTER NAME	Zone	13/14 Modelled Generation	14/15 Modelled Generation Final	Difference between Final and 13/14
Aberthaw	21	1620.00	1620.00	0.00
AChruach Wind Farm	7	0.00	49.90	49.90
Afton Wind Farm	10	68.00	0.00	-68.00
Aigas	1	20.00	20.00	0.00
An Suidhe Wind Farm, Argyll (SRO)	7	20.70	20.70	0.00
Andershaw	11	45.00	0.00	-45.00
Arecleoch	10	120.00	120.00	0.00
Baglan Bay	21	552.00	552.00	0.00
Barking	24	950.00	950.00	0.00
Barrow Offshore Wind Farm	14	90.00	90.00	0.00
Barry Power Station	21	142.00	142.00	0.00
Black Law	11	121.00	118.00	-3.00
Blackcraig Wind Farm	10	71.30	0.00	-71.30
Blacklaw Extension	11	69.00	0.00	-69.00
Brigg	16	260.00	155.00	-105.00
Enfield	24	408.00	408.00	0.00
Britned	24	1200.00	1200.00	0.00
Carraig Gheal Wind Farm	7	46.00	46.00	0.00
Carrington Power Station	16	0.00	910.00	910.00
Clunie	5	61.20	61.20	0.00
Clyde (North)	11	220.80	220.80	0.00
Clyde (South)	11	128.80	128.80	0.00
Connahs Quay	16	1380.00	1380.00	0.00
Corby	18	401.00	401.00	0.00
Coryton	24	800.00	800.00	0.00
Cottam	16	2000.00	2000.00	0.00
CDCL	16	395.00	395.00	0.00
Cowes	26	145.00	145.00	0.00
Cruachan	8	440.00	440.00	0.00
Crystal Rig 2	11	138.00	138.00	0.00
Culligran	1	19.10	19.10	0.00
Damhead Creek	24	805.00	805.00	0.00
Deanie	1	38.00	38.00	0.00
Deeside	16	515.00	515.00	0.00
Dersalloch	10	69.00	69.00	0.00
Didcot B	25	1550.00	1550.00	0.00
Didcot A GTs	25	100.00	0.00	-100.00
Dinorwig	19	1644.00	1644.00	0.00

TEC REGISTER NAME	Zone	13/14 Modelled Generation	14/15 Modelled Generation Final	Difference between Final and 13/14
Drax	15	3906.00	3906.00	0.00
Dungeness B	24	1081.00	1081.00	0.00
Dunlaw Extension	11	29.75	29.75	0.00
East West Interconnector	16	500.00	500.00	0.00
Edinbane Wind, Skye	4	41.40	41.40	0.00
Eggborough	15	1940.00	1940.00	0.00
Errochty	5	75.00	75.00	0.00
Ewe Hill	12	18.00	12.00	-6.00
Fallago	11	144.00	144.00	0.00
Farr Wind Farm, Tomatin	1	92.00	92.00	0.00
Fasnakyle G1 & G3	3	46.00	46.00	0.00
Fawley	26	75.00	75.00	0.00
Fawley CHP	26	158.00	158.00	0.00
Ferrybridge C	15	1986.00	1014.00	-972.00
Ffestiniog	16	360.00	360.00	0.00
Fiddlers Ferry	15	1987.00	1987.00	0.00
Finlarig	6	16.50	16.50	0.00
Foyers	1	300.00	300.00	0.00
IFA Interconnector	24	1988.00	2000.00	12.00
Glendoe	3	100.00	99.90	-0.10
Glenmoriston	3	37.00	37.00	0.00
Gordonbush Wind	1	70.00	70.00	0.00
Grain	24	2645.00	1524.00	-1121.00
BP Grangemouth	9	120.00	120.00	0.00
Great Yarmouth	18	420.00	405.00	-15.00
Greater Gabbard Offshore Wind Farm	18	500.00	500.00	0.00
Griffin Wind Farm	5	188.60	188.60	0.00
Gunfleet Sands Offshore Wind Farm	18	99.90	99.90	0.00
Gunfleet Sands II Offshore Wind Farm	18	64.00	64.00	0.00
Gwynt Y Mor Offshore Wind Farm - Stage 3	16	432.00	565.00	133.00
Hadyard Hill	10	117.00	117.00	0.00
Harestanes	12	142.00	126.00	-16.00
Hartlepool	13	1207.00	1207.00	0.00
Heysham Power Station	14	2406.00	2406.00	0.00
Hinkley Point B	26	1261.00	1261.00	0.00
Humber Gateway Offshore Wind Farm	15	220.00	220.00	0.00
Hunterston	10	1074.00	1074.00	0.00
Immingham	15	1218.00	1218.00	0.00
Immingham Renewable Power Station	15	290.00	0.00	-290.00
Indian Queens	27	140.00	140.00	0.00
Invergarry	3	20.00	20.00	0.00
Ironbridge	18	964.00	964.00	0.00

TEC REGISTER NAME	Zone	13/14 Modelled Generation	14/15 Modelled Generation Final	Difference between Final and 13/14
Keadby	16	735.00	735.00	0.00
Strath Brora Wind, Brora	1	67.00	67.00	0.00
Killingholme 2	15	665.00	665.00	0.00
Killingholme	15	900.00	900.00	0.00
Kilmorack	1	20.00	20.00	0.00
Langage	27	905.00	905.00	0.00
Lincs Offshore Wind Farm	17	250.00	250.00	0.00
Little Barford	18	740.00	740.00	0.00
Littlebrook	24	800.00	800.00	0.00
Lochay	6	47.00	47.00	0.00
Lochluichart	1	51.00	69.00	18.00
London Array Stages 1- 4	24	630.00	630.00	0.00
Longannet	9	2260.00	2260.00	0.00
Luichart	1	34.00	34.00	0.00
Marchwood	26	900.00	900.00	0.00
Margree	10	42.50	0.00	-42.50
Mark Hill Wind Farm	10	56.00	56.00	0.00
Medway Power Station	24	700.00	700.00	0.00
Millennium Wind (Stage 3), Ceannacroc	3	65.00	65.00	0.00
Mossford	1	18.66	18.66	0.00
Auchencrosh (Interconnector CCT)	10	80.00	80.00	0.00
Nant	7	15.00	15.00	0.00
Neilston	10	80.00	0.00	-80.00
Newfield Wind Farm	12	60.00	0.00	-60.00
Ormonde Offshore Wind Farm	14	150.00	150.00	0.00
Orrin	1	18.00	18.00	0.00
Pembroke Power Station	20	2199.00	2199.00	0.00
Pencloe	10	63.00	0.00	-63.00
Peterborough	17	230.00	245.00	15.00
Peterhead	2	1180.00	400.00	-780.00
Quoich	3	18.00	18.00	0.00
Ratcliffe on Soar	18	2021.00	2021.00	0.00
Robin Rigg East	12	92.00	92.00	0.00
Robin Rigg West	12	92.00	92.00	0.00
Rocksavage	16	810.00	810.00	0.00
Roosecote	14	152.00	0.00	-152.00
Rugeley	18	1018.00	1018.00	0.00
Rye House	24	715.00	715.00	0.00
Saltend	15	1100.00	1100.00	0.00
Seabank	22	1234.00	1234.00	0.00
Sellafield	14	155.00	155.00	0.00
Severn Power	21	850.00	850.00	0.00
Sheringham Shoal Offshore Windfarm	18	315.00	315.00	0.00

TEC REGISTER NAME	Zone	13/14 Modelled Generation	14/15 Modelled Generation Final	Difference between Final and 13/14
Shoreham	25	420.00	420.00	0.00
Sizewell B	18	1212.00	1212.00	0.00
Sloy G2 and G3	8	80.00	80.00	0.00
South Humberbank	15	1285.00	1285.00	0.00
Spalding	17	880.00	880.00	0.00
Stacain Wind Farm	8	42.50	0.00	-42.50
Staythorpe C	16	1728.00	1728.00	0.00
Sutton Bridge	17	819.00	819.00	0.00
Taylors Lane	23	144.00	144.00	0.00
Teesside	13	45.00	0.00	-45.00
Thanet Offshore Windfarm	24	300.00	300.00	0.00
Tilbury B	24	810.00	0.00	-810.00
Toddleburn Wind Farm	11	27.60	27.60	0.00
Torness	11	1215.00	1215.00	0.00
Ulzieside	10	30.00	0.00	-30.00
Uskmouth	21	345.00	0.00	-345.00
Walney I Offshore Wind Farm	14	182.00	182.00	0.00
Walney II Offshore Wind Farm	14	182.00	182.00	0.00
West Burton A	16	1987.00	1987.00	0.00
West Burton B	16	1305.00	1305.00	0.00
West of Duddon Sands Offshore Wind Farm	14	204.00	382.00	178.00
Westermost Rough	15	0.00	205.00	205.00
Whitelee	10	322.00	305.00	-17.00
Whitelee Extension	10	238.00	206.00	-32.00
Whiteside Hill	10	27.00	0.00	-27.00
Wilton	13	99.00	141.00	42.00
Wylfa	19	490.00	450.00	-40.00
	Totals	**82084.31**	**78199.81**	**-3884.50**

Appendix B: Zonal generation and demand information

Generation changes (MW)

Zone	Zone Name	Modelled Generation 13/14	Modelled Generation 14/15 Final	Difference between 13/14 and Final 14/15
1	North Scotland	747.76	**765.76**	18.00
2	East Aberdeenshire	1180.00	**400.00**	-780.00
3	Western Highlands	286.00	**285.90**	-0.10
4	Skye and Lochalsh	41.40	**41.40**	0.00
5	Eastern Grampian and Tayside	324.80	**324.80**	0.00
6	Central Grampian	63.50	**63.50**	0.00
7	Argyll	81.70	**131.60**	49.90
8	The Trossachs	562.50	**520.00**	-42.50
9	Stirlingshire and Fife	2380.00	**2380.00**	0.00
10	South West Scotland	2457.80	**2027.00**	-430.80
11	Lothian and Borders	2138.95	**2021.95**	-117.00
12	Solway and Cheviot	404.00	**322.00**	-82.00
13	North East England	1351.00	**1348.00**	-3.00
14	North Lancashire and The Lakes	3521.00	**3547.00**	26.00
15	South Lancashire, Yorkshire and Humber	15497.00	**14440.00**	-1057.00
16	North Midlands and North Wales	12407.00	**13345.00**	938.00
17	South Lincolnshire and North Norfolk	2179.00	**2194.00**	15.00
18	Mid Wales and The Midlands	7754.90	**7739.90**	-15.00
19	Anglesey and Snowdon	2134.00	**2094.00**	-40.00
20	Pembrokeshire	2199.00	**2199.00**	0.00
21	South Wales & Gloucester	3509.00	**3164.00**	-345.00
22	Cotswolds	1234.00	**1234.00**	0.00
23	Central London	144.00	**144.00**	0.00
24	Essex and Kent	13832.00	**11913.00**	-1919.00
25	Oxfordshire, Surrey and Sussex	2070.00	**1970.00**	-100.00
26	Somerset and Wessex	2539.00	**2539.00**	0.00
27	West Devon and Cornwall	1045.00	**1045.00**	0.00
	Totals and Differences	**82084.31**	**78199.81**	**-3884.50**

Demand changes (MW)

Zone	Zone Name	13/14	14/15	Diff	%
1	Northern Scotland	1,247	882	-365	-29%
2	Southern Scotland	3,921	3,770	-151	-4%
3	Northern	2,676	2,939	263	10%
4	North West	4,242	4,011	-231	-5%
5	Yorkshire	5,213	4,787	-426	-8%
6	N Wales & Mersey	3,553	2,546	-1,007	-28%
7	East Midlands	5,699	5,188	-511	-9%
8	Midlands	5,144	4,808	-336	-7%
9	Eastern	6,925	6,693	-232	-3%
10	South Wales	2,169	2,120	-49	-2%
11	South East	4,188	3,883	-305	-7%
12	London	6,053	5,944	-109	-2%
13	Southern	6,387	6,236	-151	-2%
14	South Western	2,801	2,810	9	0%
	Total Demand (MW)	**60,218**	**56,617**	**-3,601**	**-6%**

Appendix C: Generation Zones