Tariff Information Paper

Forecast TNUoS tariffs from 2014/15 to 2018/19

This information paper provides a forecast of Transmission Network Use of System (TNUoS) tariffs from 2014/15 to 2018/19. These tariffs apply to generators and suppliers.

This annual publication is intended to show how tariffs may evolve over the next five years. The forecast tariffs for 2015/16 will be refined throughout the year.

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Contents

Any Questions?

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1. Executive Summary

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. The resulting charges reflect the use and impact that customers have on the transmission network. In order that customers can appropriately respond to transmission charges, National Grid produces a variety of tariff forecasts. This document contains tariffs from 2014/15 to 2018/19. Tariffs for 2014/15 have been set and are fixed. Tariffs for 2015/16 were discussed in more detail in the April view of TNUoS tariffs for 2015/16[1].

We have included forecasts based on the current charging methodology and Diversity 1 which forms part of Ofgem's minded to position of Working-group Alternative Code Modification 2 under CUSC Modification Proposal CMP213 (Project Transmit). Both forecasts take account of the Western HVDC link from 2016/17 in line with the proposed methodology forming a second part of CMP213 Work Group Alternative WACM2. Forecasts take into account changes in Generation and Demand connected to the transmission system; changes in the transmission network due to investments undertaken by transmission owners (TOs); and changes in the revenues required to undertake this work.

Previous forecasts have used contracted Transmission Entry Capacity (TEC) to determine the locational element of tariffs. This has tended to over-estimate TEC so this year a view has been taken as to what generation is considered likely to connect. This view has been based upon market intelligence, e.g. if timescales to build a project are unrealistic given that planning permission for a power station has not been achieved it has been assumed that the project will apply to delay its connection date and the expected generation will not connect according to contracted timescales. As this view is based upon commercially sensitive information Generation has not been broken down to individual station level.

Tariffs have been based upon the forecast combined revenue allowances of onshore and offshore Transmission Owners. These revenues include a forecast of inflation, changes to onshore TO allowed revenue under RIIO price controls and a forecast of offshore transmission owners' revenue.

Currently an EU regulation limits the average annual use of system charges that generators pay to €2.5/MWh. With rising revenues this limit is expected to be reached in 2015/16. The April view of 2015/16 TNUoS tariffs assumed that the proportion paid by Generation would reduce in accordance with CUSC Modification Proposal CMP224. That proposal is still being considered but ACER published an opinion in late April that may affect this limit. We have therefore changed our central view of the proportions for Generation and Demand to 27:73 as in the current charging methodology. However, both scenarios are presented in this document given the uncertainty.

Locational Generation and Demand tariffs see increased locational variances in 2016/17 due to the completion of the Western HVDC link. This link between Hunterston in Western Scotland and

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

Deeside in North Wales is being built to aid the delivery of renewable energy between Scotland and England & Wales. The HVDC link generally increases Generation tariffs in the North and decreases Generation tariffs in the South, with the opposite effect on Demand tariffs.

In 2018/19 new offshore wind farms in Scotland increase North to South flows, generally increasing Generation tariffs in the North and decreasing Generation tariffs in the South, with the opposite effect on Demand tariffs. Certain zones do reverse this trend where large scale Generation projects connect.

2. Structure of this Document

Section 3 contains forecast tariffs from 2015/16 to 2018/19. Forecasts are provided for the current methodology and also for the Diversity 1 methodology forming part of CMP213 WACM 2. Ofgem's further consultation on CMP213, published on 25 April, indicates it is minded to implement WACM2 from 2016/17.

Section 4 discusses the key drivers for tariff changes over the next five years. As well as changes to the Generation and Demand background, the commissioning of the Western HVDC link is a significant change. The methodology for the incorporation of this circuit technology into the TNUoS charging methodology is part of CMP213. We have used the proposed methodology under CMP213 WACM2 to calculate its impact using both current and Diversity methodologies. Additionally there are also a number of separate charging methodology changes under consideration, the impact of which are discussed here.

Sections 5 and 6 discuss the forecast Generation and Demand tariffs under the current methodology.

Sections 7 and 8 discuss changes to the proportions of revenue recovered from generation and demand and how this and changes to revenue impact the residual element of tariffs.

Sections 9 and 10 provide details of how additional information may be obtained, including the load flow model. The timetable for future updates this year and how to provide feedback to National Grid on the content of this document are also included.

3. Five Year Tariff Forecast Tables

This section contains information on Generation and Demand Tariffs from 2014/15 to 2018/19 under the Current Methodology. Tariffs for 2014/15 are as detailed in the Statement of Use of System Charges Issue 10 Revision 1 effective from 1 April 2014[2].

Our central view of tariffs is that 27% of revenue will be recovered from Generation and 73% from Demand in line with current charging methodology. This is a change to the April view of TNUoS tariffs for 2015/16[3] which assumed a lower proportion for generation and is presented in Appendix C. See Sections 7 and 8 for more information.

This section also contains forecast Generation and Demand tariffs from 2015/16 using the Diversity 1 methodology which forms part of CMP213 WACM 2. Ofgem published their further consultation on CMP213 on 25 April which indicated that it was minded to implement WACM2 from 2016/17; however, we have included tariffs from 2015/16 for completeness.

Onshore Local Circuit and Substation tariffs are discussed in Sections 5.4 and 5.5. Offshore Local tariffs are inflated by RPI once set. Future offshore tariffs are dependent on asset costs and asset transfer date. If you would like to discuss these further please contact mary.owen@nationalgrid.com, 01926 653845.

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[2] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Statement-of-Use-of-System-Charges/

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

3.1 Generation Tariffs – Current Methodology

The tariffs detailed below are based on current methodology with the proposed methodology under CMP213 WACM2 for HVDC cables from 2016/17 onwards as described in Section 4.2.

Table 1 – Generation Tariffs under Current Methodology

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	North Scotland	27.68	26.86	36.98	38.17	37.78
2	East Aberdeenshire	22.97	22.53	32.90	34.02	34.55
3	Western Highlands	28.35	25.02	35.33	36.48	35.74
4	Skye and Lochalsh	33.79	30.47	40.97	42.28	33.20
5	Eastern Grampian and Tayside	24.02	23.40	33.93	35.06	34.74
6	Central Grampian	21.97	22.40	33.57	34.71	33.89
7	Argyll	20.85	22.34	33.99	35.16	33.88
8	The Trossachs	18.42	19.09	30.58	31.65	30.59
9	Stirlingshire and Fife	18.02	18.26	28.94	29.72	28.04
10	South West Scotland	16.46	17.12	29.88	30.66	28.94
11	Lothian and Borders	14.18	14.33	22.26	22.94	21.72
12	Solway and Cheviot	12.73	12.79	19.19	19.84	17.65
13	North East England	9.87	9.56	12.34	12.51	11.85
14	North Lancs and The Lakes	9.15	8.91	9.63	9.60	8.29
15	South Lancs, Yorks and Humber	7.61	7.23	6.91	6.88	5.28
16	North Midlands and North Wales	6.17	5.70	3.98	3.73	1.90
17	South Lincs and North Norfolk	4.65	3.93	3.08	2.90	0.87
18	Mid Wales and The Midlands	3.55	2.97	1.67	1.40	-0.35
19	Anglesey and Snowdon	8.57	8.26	4.50	4.16	3.24
20	Pembrokeshire	6.55	6.13	4.66	4.45	1.16
21	South Wales	3.78	3.54	1.91	1.55	-2.37
22	Cotswold	0.75	0.30	-1.36	-1.79	-5.15
23	Central London	-3.78	-4.28	-5.53	-6.03	-8.23
24	Essex and Kent	1.43	0.16	-1.21	-2.12	-4.02
25	Oxfordshire, Surrey and Sussex	-0.83	-1.50	-3.05	-3.65	-5.89
26	Somerset and Wessex	-2.71	-3.53	-5.26	-5.90	-8.76
27	West Devon and Cornwall	-4.70	-5.53	-7.68	-8.33	-12.21

3.2 Generation Tariffs – Diversity 1

Under the proposed CMP213 Diversity 1 methodology, the tariff paid by a generator depends on the zone into which the generator connects; whether the generator is conventional or intermittent; and the generator's specific annual load factor. It is built up from four tariff elements as follows:

- **System Peak:** Payable by conventional generators only
- **Shared Year Round:** Payable by all generators scaled by each generator's specific annual load factor
- **Not Shared Year Round**: Payable by all. (Where no tariff is shown in the tables use £0/kW.)
- **Residual:** Payable by all

To illustrate the combined effect of these elements we have included examples of the tariff that would be paid by:

- A conventional generator with an annual load factor of 70%
- An intermittent generator with an annual load factor of 30%.

Table 2 – 2015/16 Generation Tariffs under Diversity 1

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.91	13.71	6.21	3.21	21.92	13.53
2	East Aberdeenshire	3.88	8.07	6.21	3.21	18.94	11.84
3	Western Highlands	2.95	11.99	6.01	3.21	20.56	12.81
4	Skye and Lochalsh	-2.64	11.99	5.88	3.21	14.84	12.68
5	Eastern Grampian and Tayside	2.56	10.92	5.66	3.21	19.06	12.14
6	Central Grampian	4.44	10.46	5.40	3.21	20.36	11.74
7	Argyll	3.59	8.44	7.59	3.21	20.29	13.33
8	The Trossachs	3.66	8.44	4.16	3.21	16.93	9.90
9	Stirlingshire and Fife	3.86	7.88	4.00	3.21	16.58	9.57
10	South West Scotland	2.89	9.32	4.00	3.21	16.62	10.00
11	Lothian and Borders	3.00	9.32	0.06	3.21	12.78	6.06
12	Solway and Cheviot	1.60	5.63	2.77	3.21	11.52	7.66
13	North East England	3.23	3.11	1.09	3.21	9.71	5.23
14	North Lancashire and The Lakes	1.70	3.11	1.81	3.21	8.89	5.95
15	South Lancashire, Yorkshire and Humber	3.97	0.93		3.21	7.82	3.48
16	North Midlands and North Wales	3.54	-0.09		3.21	6.69	3.18
17	South Lincolnshire and North Norfolk	1.92	-0.44		3.21	4.82	3.07
18	Mid Wales and The Midlands	1.32	-0.35		3.21	4.28	3.10
19	Anglesey and Snowdon	4.95	1.18		3.21	8.98	3.56
20	Pembrokeshire	7.84	-3.49		3.21	8.61	2.16
21	South Wales & Gloucester	5.38	-3.51		3.21	6.13	2.15
22	Cotswold	2.13	2.17	-5.57	3.21	1.29	-1.71
23	Central London	-3.99	2.17	-4.86	3.21	-4.14	-1.01
24	Essex and Kent	-4.62	2.17		3.21	0.10	3.86
25	Oxfordshire, Surrey and Sussex	-1.83	-2.08		3.21	-0.08	2.58
26	Somerset and Wessex	-2.01	-3.29		3.21	-1.11	2.22
27	West Devon and Cornwall	-0.04	-3.92		3.21	0.42	2.03

Table 3 – 2016/17 Generation Tariffs under Diversity 1

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	1.97	18.68	11.95	3.29	30.28	20.84
2	East Aberdeenshire	2.73	13.42	11.95	3.29	27.35	19.26
3	Western Highlands	2.07	17.52	11.57	3.29	29.19	20.11
4	Skye and Lochalsh	-1.98	17.52	13.16	3.29	26.74	21.71
5	Eastern Grampian and Tayside	2.05	16.38	10.90	3.29	27.71	19.10
6	Central Grampian	3.88	16.35	10.88	3.29	29.49	19.07
7	Argyll	2.97	14.73	12.69	3.29	29.26	20.39
8	The Trossachs	3.04	14.73	9.38	3.29	26.01	17.08
9	Stirlingshire and Fife	3.04	13.80	8.93	3.29	24.92	16.36
10	South West Scotland	2.79	16.79	8.93	3.29	26.76	17.26
11	Lothian and Borders	2.53	16.79	0.50	3.29	18.06	8.82
12	Solway and Cheviot	1.52	9.27	5.67	3.29	16.97	11.73
13	North East England	3.02	4.06	3.10	3.29	12.25	7.61
14	North Lancashire and The Lakes	1.41	4.06	2.12	3.29	9.65	6.62
15	South Lancashire, Yorkshire and Humber	3.87	0.97		3.29	7.84	3.58
16	North Midlands and North Wales	3.22	-1.03		3.29	5.79	2.98
17	South Lincolnshire and North Norfolk	0.92	0.16	0.00	3.29	4.32	3.33
18	Mid Wales and The Midlands	1.06	-0.82		3.29	3.77	3.04
19	Anglesey and Snowdon	3.53	-0.62		3.29	6.38	3.10
20	Pembrokeshire	8.22	-5.01		3.29	8.00	1.78
21	South Wales & Gloucester	5.85	-5.17		3.29	5.52	1.74
22	Cotswold	2.56	0.81	-5.92	3.29	0.49	-2.39
23	Central London	-2.70	0.81	-4.84	3.29	-3.70	-1.32
24	Essex and Kent	-4.21	0.81		3.29	-0.36	3.53
25	Oxfordshire, Surrey and Sussex	-1.46	-3.39		3.29	-0.55	2.27
26	Somerset and Wessex	-1.75	-5.17		3.29	-2.09	1.73
27	West Devon and Cornwall	-1.26	-7.33		3.29	-3.10	1.09

Table 4 - 2017/18 Generation Tariffs under Diversity 1

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	3.09	16.89	12.61	3.07	30.60	20.75
2	East Aberdeenshire	3.81	11.36	12.61	3.07	27.44	19.09
3	Western Highlands	3.20	15.55	12.09	3.07	29.24	19.82
4	Skye and Lochalsh	-0.97	15.55	13.74	3.07	26.72	21.47
5	Eastern Grampian and Tayside	3.13	14.45	11.40	3.07	27.70	18.80
6	Central Grampian	5.00	14.35	11.31	3.07	29.43	18.68
7	Argyll	4.12	12.68	13.10	3.07	29.16	19.97
8	The Trossachs	4.18	12.68	9.67	3.07	25.79	16.54
9	Stirlingshire and Fife	4.15	11.79	9.22	3.07	24.69	15.82
10	South West Scotland	3.99	14.27	9.22	3.07	26.26	16.56
11	Lothian and Borders	3.56	14.27	1.86	3.07	18.48	9.21
12	Solway and Cheviot	2.34	7.73	5.59	3.07	16.41	10.98
13	North East England	3.30	3.76	3.13	3.07	12.12	7.32
14	North Lancashire and The Lakes	3.06	3.76	0.70	3.07	9.46	4.90
15	South Lancashire, Yorkshire and Humber	4.20	1.03		3.07	7.99	3.38
16	North Midlands and North Wales	3.98	-1.12		3.07	6.26	2.73
17	South Lincolnshire and North Norfolk	1.40	0.02	0.00	3.07	4.48	3.07
18	Mid Wales and The Midlands	1.45	-0.78		3.07	3.97	2.83
19	Anglesey and Snowdon	7.04	-3.83		3.07	7.42	1.92
20	Pembrokeshire	6.99	-3.78		3.07	7.41	1.93
21	South Wales & Gloucester	4.28	-3.94		3.07	4.59	1.88
22	Cotswold	0.93	1.58	-5.52	3.07	-0.42	-1.98
23	Central London	-5.24	1.58	-5.12	3.07	-6.20	-1.58
24	Essex and Kent	-4.72	1.58		3.07	-0.55	3.54
25	Oxfordshire, Surrey and Sussex	-2.53	-1.88		3.07	-0.77	2.50
26	Somerset and Wessex	-3.25	-3.92		3.07	-2.93	1.89
27	West Devon and Cornwall	-2.80	-6.16		3.07	-4.05	1.22

Table 5 - 2018/19 Generation Tariffs under Diversity 1

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.09	14.25	20.66	1.13	33.86	26.07
2	East Aberdeenshire	1.60	11.89	19.54	1.13	30.60	24.24
3	Western Highlands	2.61	13.59	19.28	1.13	32.53	24.49
4	Skye and Lochalsh	-1.69	13.59	21.05	1.13	30.00	26.26
5	Eastern Grampian and Tayside	3.77	13.08	17.95	1.13	32.02	23.01
6	Central Grampian	3.38	12.86	17.28	1.13	30.79	22.27
7	Argyll	2.71	12.23	18.67	1.13	31.07	23.47
8	The Trossachs	2.71	12.23	15.37	1.13	27.77	20.17
9	Stirlingshire and Fife	2.47	11.41	13.92	1.13	25.51	18.48
10	South West Scotland	2.97	12.60	14.21	1.13	27.13	19.12
11	Lothian and Borders	2.60	12.60	6.40	1.13	18.96	11.31
12	Solway and Cheviot	2.17	7.20	8.24	1.13	16.58	11.53
13	North East England	3.38	3.89	4.37	1.13	11.61	6.67
14	North Lancashire and The Lakes	1.53	3.89	2.89	1.13	8.28	5.19
15	South Lancashire, Yorkshire and Humber	4.03	1.21		1.13	6.01	1.50
16	North Midlands and North Wales	3.12	-0.97		1.13	3.57	0.84
17	South Lincolnshire and North Norfolk	2.57	-1.64		1.13	2.55	0.64
18	Mid Wales and The Midlands	1.04	-0.99		1.13	1.48	0.84
19	Anglesey and Snowdon	1.93	1.27		1.13	3.95	1.51
20	Pembrokeshire	8.32	-5.82		1.13	5.38	-0.61
21	South Wales & Gloucester	5.47	-6.24		1.13	2.24	-0.74
22	Cotswold	2.25	0.50	-6.57	1.13	-2.84	-5.28
23	Central London	-3.11	0.50	-5.03	1.13	-6.66	-3.75
24	Essex and Kent	-3.54	0.50		1.13	-2.06	1.28
25	Oxfordshire, Surrey and Sussex	-1.22	-3.72		1.13	-2.69	0.02
26	Somerset and Wessex	-1.94	-6.01		1.13	-5.02	-0.67
27	West Devon and Cornwall	-1.47	-8.27		1.13	-6.13	-1.35

3.3 Demand Tariffs - Current Methodology

The following tariffs are based on current methodology with the proposed methodology under CMP213 WACM2 for HVDC cables from 2016/17 onwards as described in section 4.2.

Table 6 – Half Hour Demand Tariffs under Current Methodology (£/kW)

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	Northern Scotland	16.17	18.61	12.67	13.05	16.89
2	Southern Scotland	21.24	22.29	15.95	16.61	21.50
3	Northern	26.94	28.67	30.44	31.64	36.07
4	North West	29.64	31.62	36.29	37.83	42.90
5	Yorkshire	30.25	32.29	37.14	38.68	43.80
6	N Wales & Mersey	29.72	31.68	38.92	40.63	45.59
7	East Midlands	33.10	35.17	40.78	42.38	48.05
8	Midlands	33.78	35.90	42.18	43.87	49.22
9	Eastern	34.63	37.09	42.59	44.32	49.96
10	South Wales	32.32	34.36	40.35	42.03	49.72
11	South East	37.66	39.84	45.81	48.01	54.04
12	London	38.55	42.25	47.65	49.97	55.98
13	Southern	38.79	41.02	46.90	48.80	54.86
14	South Western	38.70	40.70	47.09	48.99	56.70

Table 7 – Non Half-Hour Demand Tariffs under Current Methodology (p/kWh)

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	Northern Scotland	2.19	2.52	1.72	1.77	2.29
2	Southern Scotland	2.95	3.10	2.22	2.31	2.99
3	Northern	3.67	3.90	4.14	4.31	4.91
4	North West	4.24	4.53	5.20	5.42	6.14
5	Yorkshire	4.11	4.39	5.05	5.26	5.95
6	N Wales & Mersey	4.20	4.47	5.50	5.74	6.44
7	East Midlands	4.58	4.87	5.65	5.87	6.66
8	Midlands	4.74	5.04	5.92	6.16	6.91
9	Eastern	4.75	5.09	5.84	6.08	6.85
10	South Wales	4.27	4.54	5.33	5.55	6.57
11	South East	5.17	5.47	6.29	6.59	7.42
12	London	5.14	5.63	6.35	6.66	7.46
13	Southern	5.38	5.69	6.51	6.77	7.61
14	South Western	5.24	5.51	6.37	6.63	7.67

3.4 Demand Tariffs – Diversity 1

The following tariffs have been calculated using the Diversity 1 methodology which forms part of CMP213 WACM 2

Table 8 – Half-Hour Demand Tariffs under Diversity 1 (£/kW)

Zone	Zone Name	15/16	16/17	17/18	18/19
1	Northern Scotland	21.15	15.98	18.18	18.54
2	Southern Scotland	22.42	17.10	19.36	22.02
3	Northern	28.44	30.44	32.12	36.27
4	North West	31.52	36.15	37.87	43.05
5	Yorkshire	32.22	37.04	38.57	43.98
6	N Wales & Mersey	31.52	38.54	40.10	45.65
7	East Midlands	35.10	40.65	42.00	48.22
8	Midlands	35.65	41.80	43.56	49.48
9	Eastern	37.30	42.71	44.11	50.16
10	South Wales	33.67	39.54	41.46	48.18
11	South East	40.37	46.17	47.72	54.09
12	London	43.08	48.10	49.97	56.23
13	Southern	40.71	46.75	48.29	54.84
14	South Western	39.13	46.07	48.19	54.97

Table 9 – Non Half-Hour Demand Tariffs under Diversity 1 (p/kWh)

Zone	Zone Name	15/16	16/17	17/18	18/19
1	Northern Scotland	2.86	2.16	2.46	2.51
2	Southern Scotland	3.12	2.38	2.69	3.06
3	Northern	3.87	4.14	4.37	4.94
4	North West	4.51	5.18	5.42	6.16
5	Yorkshire	4.38	5.04	5.24	5.98
6	N Wales & Mersey	4.45	5.44	5.66	6.45
7	East Midlands	4.86	5.63	5.82	6.68
8	Midlands	5.00	5.87	6.11	6.94
9	Eastern	5.12	5.86	6.05	6.88
10	South Wales	4.45	5.22	5.48	6.37
11	South East	5.54	6.34	6.55	7.43
12	London	5.74	6.41	6.66	7.50
13	Southern	5.65	6.49	6.70	7.61
14	South Western	5.30	6.24	6.52	7.44

4. Key Drivers for Tariff Changes

Factors which affect tariffs include methodology, changes to the Transport model used to calculate the locational element and changes to the Tariff model used to calculate the residual element of tariffs. There are five main drivers behind tariff changes over the next five years:

- CMP213 (Project TransmiT) sharing proposals
- CMP213 (Project TransmiT) parallel HVDC proposals
- Contracted Generation
- Generation/Demand Revenue proportions
- Transmission Owner Revenues

4.1 CMP213 (Project TransmiT) sharing proposals

CMP213 is the CUSC modification proposal arising from Ofgem's wholesale review of gas and electricity transmission charging arrangements, Project TransmiT[4]. On conclusion of Ofgem's Significant Code Review (SCR) process as part of Project TransmiT National Grid were directed to raise a CUSC modification proposal (CMP213) seeking to consider three potential improvements to the TNUoS charging methodology[5]. The first of these potential improvements was to better reflect the impact of a specific generator on transmission investment requirements (commonly referred to as the 'sharing' element of the proposal). The CUSC process concluded last year and CMP213 is currently awaiting an Ofgem determination.

On 25th April 2014 Ofgem published a further consultation on CMP213 which restated the Regulator's minded to position to implement Working Group Alternative Modification WACM2, but now from April 2016. The sharing' element of WACM2 was the Diversity 1 methodology. Under Ofgem's minded to position, the current methodology would apply for 2014/15 and 2015/16 and the Diversity 1 methodology from 2016/17 onwards. As this is only a minded to position, we have provided forecasts under both methodologies from 2015/16 to 2018/19. Tariffs for 2014/15 have already been set using current methodology.

4.2 CMP213 (Project TransmiT) parallel HVDC proposals

The second element of CMP213 (Project TransmiT) was the consideration of parallel HVDC circuits within the TNUoS charging methodology as the current charging methodology does not prescribe how parallel HVDC circuits should be included in the Transport model.

CMP213 WACM2, Ofgem's current minded to position, provides a methodology for the treatment of parallel HVDC circuits within the TNUoS charging methodology. As the Western HVDC link is

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[4] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

[5] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

scheduled to be commissioned from 2016/17 we have applied this proposed methodology to tariffs under both current and Diversity 1 methodologies from 2016/17 onwards. The application of this proposed methodology for parallel HVDC circuits is described in Appendix A.

4.3 Contracted Generation

In previous publications, Generation data used to create the transport model has been based upon contracted TEC. Contracted Generation significantly affects tariff forecasts and it is recognised that contracted TEC has not always been a good representation due to station closures, Generation project delays and terminations. Therefore, this year the Generation data used within this forecast is National Grid's best view based upon contracted TEC (from the TEC register), and market intelligence. Market intelligence has been used to derive a view as to the likelihood of a number of new Generation projects progressing as planned. Where progression looked likely to vary from plan, the relevant market intelligence was used to produce a revised view as to how the project was likely to progress. The contracted TEC held for those projects was then adjusted in line with this view. The overall result of these adjustments is that National Grid's best view is less than the contracted TEC shown in the TEC register. We are unable to breakdown the modelled TEC as some of the information used to derive the data could be commercially sensitive.

Table 10 shows the total Generation TEC that has been included in the charging model from 2014/15 to 2018/19 and the contracted Generation for that year.

Table 10 – Contracted and Modelled TEC (GW)

	2014/15	2015/16	2016/17	2017/18	2018/19
Contracted TEC	77.2	80.3	91.1	101.6	119.6
Modelled TEC	77.2	79.5	82.5	85.7	95.7

4.4 Generation/Demand Revenue Proportions

Under the current charging methodology, tariffs are set to recover 27% of TNUoS revenue from Generation and 73% from Demand. EU Regulation ECR 838/2010 limits the amount that can be recovered from Generation to an average of €2.5/MWh per annum. With increasing revenues this limit is expected to be reached in 2015/16. CUSC modification proposal CMP224 is currently under consideration and seeks to adjust the balance of TNUoS charges between Generation and Demand to remain compliant with the regulation. However, ACER recently published an opinion that may affect this limit[6].

The tariffs in this forecast retain the existing proportions for revenue recovery from Demand and Generation in all years. Section 7 describes the methodology for calculating alternative proportions and Section 8 describes the methodology for calculating the consequential impact on Demand and

[6] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf

Generation residuals. Appendix C contains an example of how the tariffs could alter if a €2.5/MWh limit was applied.

4.5 Transmission Owners' Revenue

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs) in Great Britain. The tariffs have been calculated to recover the revenues shown in Table 11. The tariffs for 2014/15 have been set so the revenue assumptions for that year are unchanged. The revenue for 2015/16 is the same as that published in the April update of 2015/16 TNUoS tariffs.

Table 11 – Transmission Owner Revenues

	2014/15	2015/16	2016/17	2017/18	2018/19
National Grid	1,763.2	1851.6	2,146.3	2,218.0	2,440.1
Scottish Power Transmission	312.2	331.8	333.6	349.6	366.0
SHE Transmission	214.0	215.2	242.1	235.9	242.7
Offshore	218.4	276.4	291.6	335.6	515.3
Network Innovation Competition	17.8	16.6	17.3	18.2	18.4
Total	**2,524.3**	**2,691.6**	**3,031.1**	**3,157.3**	**3,582.5**
Pre-vesting connections	47.0	47.0	47.0	47.0	47.0
TNUoS	2,477.3	2,644.7	2,984.1	3,110.4	3,535.6
Total	**2,524.3**	**2,691.6**	**3,031.1**	**3,157.3**	**3,582.5**

All figures are in millions of pounds and nominal 'money of the day'. The inflation factors used are relative to 2009/10 (the price base for current price controls) and are detailed in Table 12.

Table 12 – Inflation Indices

2009/10	2014/15	2015/16	2016/17	2017/18	2018/19
1.0000	1.2051	1.2326	1.2819	1.3144	1.3652

4.5.1 Onshore Transmission Owners

The revenues of the Onshore Transmission Owners (TOs) are subject to RIIO price controls set by Ofgem in 2012. RIIO stands for Revenue = Incentives + Innovation + Outputs. This means that TO revenues are set at price review, but then adjusted during the price control period depending on performance against incentives, innovation and delivered output. Outputs consist of replaced transmission equipment and new capacity driven by customer requirements.

The RIIO price controls include incentives for Stakeholder Satisfaction, SF_6 Leakage, Reliability and Connections. They also include a Total expenditure Incentive Mechanism (TIM) which adjusts allowances to reflect variations in outputs against what was assumed at the price review. Actual expenditure is compared against these adjusted allowances with the difference shared between TO and customers. 2013/14 was the first year of the RIIO price control and the incentive payments arising from performance in that year will not be known until late 2014. There is therefore currently no track record of incentive performance under RIIO.

Onshore TOs have provided forecasts of revenues to 2018/19. These are subject to change as business plans and forecasts are developed. Revenues for each charging year are confirmed on 25 January before the charging year in question. National Grid's forecast is based upon Ofgem Final Proposals 'Best View.' This view is assumed to include additional revenues arising from incentives and the Network Innovation Allowance[7]. Scottish Power Transmission and SHE Transmission's forecasts are broadly similar to Ofgem's Final Proposals 'Base View' plus a forecast of additional revenue from incentives and the Network Innovation Allowance.

Where Onshore TOs are expected to receive revenues associated with Transmission Investment for Renewable Generation incentive (TIRG), this has been included. This incentive is set by Ofgem to fund specific infrastructure projects required to connect renewable Generation and is occasionally adjusted as projects incur unexpected costs or savings.

No allowances have been included for inflationary true-ups or under/over recovery of revenue from prior years, as these will not be apparent until the reconciliation process associated with earlier years is completed.

4.5.2 Offshore Transmission Owners

The revenues of offshore transmission owners (OFTOs) are determined by Ofgem in a competitive tender process. The revenue is confirmed when the network is transferred from the developer to the appointed OFTO. Prior to this there is uncertainty as to the value of the revenue stream and when it will start. Therefore, whilst the revenues for existing OFTOs are relatively predictable, the revenue for future OFTOs is a forecast. OFTO asset transfers have tended to within two years of the associated wind farm commissioning and this has been used to forecast future transfer dates. Transfer values have been extrapolated from previous values and sizes of wind farm.

Tariffs have been forecast using the central case shown in Table 13. The table also shows the effect of asset transfers being delayed by six months (low case) or advanced by six months (high case). No OFTOs are forecast to asset transfer during 2016/17.

[7] The Network Innovation Allowance allows Onshore Transmission Owners to claim a proportion of innovation expenditure up to a limit. This is separate from the Network Innovation Competition in which both Onshore and Offshore Transmission Owners competitively tender for funding.

Table 13 – Offshore Revenue Scenarios

£m Nominal	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Low			256.0	291.6	299.0	444.0
Central	165.5	218.4	276.4	291.6	335.6	515.3
High			282.4	291.6	427.5	551.4

4.5.3 Network Innovation Competition Fund

Ofgem can award up to £27m (2009/10 prices) per year under the Network Innovation Competition Fund. National Grid collects the revenue for this fund on behalf of the successful bidders. Ofgem awarded funding worth £17.8m for 2014/15. Tariffs have been forecast using the central case shown in Table 14 which assumes 50% of available funds are allocated in each year. A low case with no awards and high case with 100% award are also shown.

Table 14 – Network Innovation Competition Revenue Scenarios

£m Nominal	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Low			-	-	-	-
Central	-	17.8	16.7	17.3	18.2	18.4
High			33.3	34.6	35.5	36.9

4.5.4 Pre-Vesting Connections

The Scottish TO revenues shown in Table 11 are net of revenue due to connection assets and therefore represent the revenue recovered from TNUoS charges only. The National Grid revenue includes revenue from pre-vesting connection assets, i.e. those assets used to connect customers in England and Wales that existed at privatisation in 1990. Revenue from these assets has to be deducted to calculate the revenue to be recovered from TNUoS. Pre-vesting connection income is diminishing in real terms due to depreciation and replacement, but is broadly flat in nominal terms due to inflation.

4.5.5 Scenarios

At the March Transmission Charging Methodology forum, a request was made for Transmission Owners to provide scenarios around their forecasts. National Grid intends to work with the other TOs to develop such forecasts during the course of 2014 with a view to providing updates in its next five year forecast.

4.6 Other model inputs

The following inputs can also alter tariffs but are not main drivers within these forecasts or there has been no major change in how the inputs are derived.

4.6.1 Locational Demand

The locational model uses peak demands at each Grid Supply Point (GSP). The July 2013 Week 24 demand submissions provided by Distribution Network Operators and forecasts of directly connected demand sites such as steelworks and other heavy industry have been used. Zonal demand information is summarised in Table 15 and detailed in Appendix E. Please note that locational demand is not the same as the demand base used for charge setting.

Table 15 – Peak Half Hour Demand (GW)

2014/15	2015/16	2016/17	2017/18	2018/19
56.6	55.6	55.9	56.4	56.8

4.6.2 Transmission Network Changes

A number of provisional network changes have been made to connect new Generation and reinforce the network. These have been based on the network information provided by the TOs together with any minimal changes needed to connect Generation that is contracted to connect. The following projects are of particular note:

- Beauly-Denny reinforcement – This is included from 2015/16 and reduces Generation tariffs in the North of Scotland and increases demand tariffs in demand zones in Scotland.
- North London Reinforcement Project – This is included from 2016/17 and alters flows on the system and therefore tariffs. Flows on these new circuits are heavily determined by Generation, so if Generation changes from that forecast then the tariff can change.
- Western HVDC link – This is included from 2016/17. See section 4.2.

4.6.3 Expansion Constant

The charging methodology requires the expansion constant to be updated each year for inflation. For the purpose of preparing the tariff forecasts, the 2014/15 expansion constant has been increased by 3% each year. Table 16 shows the expansion constants used.

Table 16 – Expansion Constant

£/MWkm	14/15	15/16	16/17	17/18	18/19
Expansion Constant	12.901218	13.288255	13.686902	14.097509	14.520435

4.6.4 Generation Charging Base

The charging bases for each year are detailed in Table 27. The generator charging base for each year is based on the generator data used for the transport model. However, whilst interconnectors are included in the transport model for determining flows on the transmission system at peak demand, they are not liable for Generation or Demand TNUoS charges. Therefore, when calculating the Generation charging base the reductions in Table 17 are made to reflect the charging treatment.

Table 17 – Interconnector Adjustments

Interconnector	Zone	Adjustment (MW)
French Interconnector	24	2000
Britned	24	1200
Belgian Interconnector	24	1000 (from 2018/19)
East-West	16	500
Moyle	10	295 (from 2014/15), 80 (from 2017/18)

4.6.5 Demand Charging Base

The demand charging base and the split between Half-Hour (HH) and Non-Half-Hour (NHH) metered demand are unchanged from those used for setting charges for 2014/5. This assumes a peak system demand of 55.3GW; HH demand at triad of 15.9GW; and chargeable NHH demand of 28.6TWh[8]. The demand bases are unchanged because forecasts currently indicate minimal growth.

It should be noted that actual peak demand and the timing of the triads in any given year depends on a number of factors including prevailing weather and behaviour of commercial and industrial loads.

Outturn demand for 2013/14 shows system peaks to be around 50GW, HH demand around 15GW and chargeable NHH demand around 27.6TWh. This is significantly lower than was forecast when the 2013/14 tariffs were set and we are examining the factors behind the decrease, e.g. weather, consumer behaviour and embedded Generation. However, we are not currently forecasting a long term decrease in demand.

Changes to the demand charging base impact the residual element of demand tariffs. Section 8 shows how this is calculated to allow customers to model the impact on demand tariffs of their own forecasts of future demand.

The proportions of revenue expected to be recovered from HH demand and NHH demand is determined by the split of the forecast demand at Triad into HH and NHH demand. Typically 70% is NHH and 30% is HH. National Grid will continue to review the demand charging bases and, in particular, any changes that may result from BSC amendment proposal P272. If approved, this would transfer a proportion of commercial load with smart metering from NHH to HH demand.

[8] TNUoS charges for NHH demand is based on annual consumption between 4pm and 7pm

5. Commentary on Forecast Generation Tariffs - Current Methodology

5.1 Wider Zonal Generation Tariffs

Figure 1 illustrates the forecast wider Generation TNUoS tariffs under the current methodology set out in Section 3.1.

Figure 1

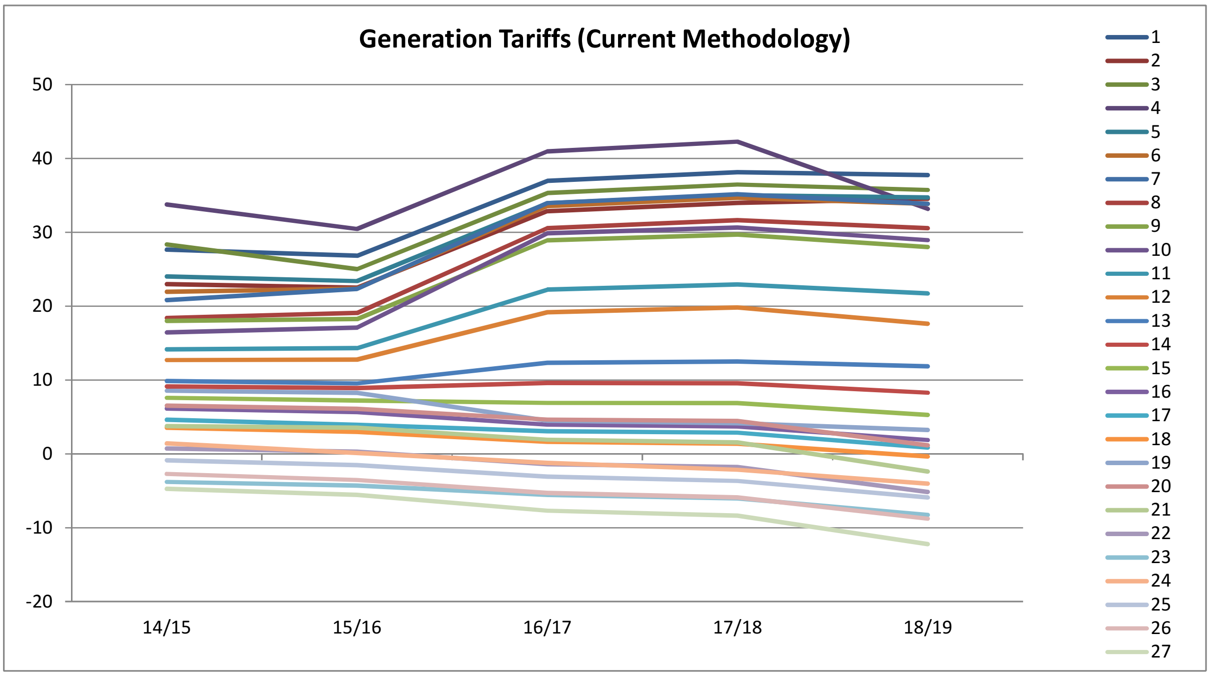

Table 18 shows the changes in wider tariffs between years. In 2016/17 there is an increase in Scottish zones and a corresponding decrease in England and Wales zones. This is due to the HVDC link between Western Scotland and North Wales.

The differential between Generation tariffs increases slightly in 2017/18 but more so in 2018/19. This is caused by large amounts of generation connecting in Northern Scotland, Northern England and North Wales which tends to increase north to south network flows.

Increased Generation in Zone 3 in 2018/19 causes a notable reduction in the Zone 4 tariff due to reversal of flows on a long radial spur.

Table 18 – Changes in Wider Generation Tariffs under Current Methodology (£/kW)

Zone	Zone Name	Change 14/15 to 15/16	Change 15/16 to 16/17	Change 16/17 to 17/18	Change 17/18 to 18/19
1	North Scotland	-0.82	10.12	1.20	-0.40
2	East Aberdeenshire	-0.44	10.37	1.11	0.53
3	Western Highlands	-3.34	10.32	1.15	-0.74
4	Skye and Lochalsh	-3.32	10.50	1.32	-9.09
5	Eastern Grampian and Tayside	-0.62	10.53	1.13	-0.32
6	Central Grampian	0.43	11.17	1.15	-0.82
7	Argyll	1.49	11.65	1.17	-1.28
8	The Trossachs	0.67	11.49	1.07	-1.06
9	Stirlingshire and Fife	0.24	10.68	0.79	-1.69
10	South West Scotland	0.66	12.76	0.78	-1.72
11	Lothian and Borders	0.14	7.94	0.67	-1.22
12	Solway and Cheviot	0.06	6.41	0.65	-2.19
13	North East England	-0.31	2.78	0.17	-0.66
14	North Lancs and The Lakes	-0.23	0.72	-0.03	-1.31
15	South Lancs, Yorks and Humber	-0.38	-0.31	-0.03	-1.60
16	North Midlands and North Wales	-0.46	-1.72	-0.25	-1.83
17	South Lincs and North Norfolk	-0.72	-0.84	-0.19	-2.03
18	Mid Wales and The Midlands	-0.57	-1.30	-0.28	-1.75
19	Anglesey and Snowdon	-0.32	-3.76	-0.34	-0.91
20	Pembrokeshire	-0.42	-1.47	-0.21	-3.29
21	South Wales	-0.24	-1.63	-0.37	-3.92
22	Cotswold	-0.45	-1.67	-0.42	-3.37
23	Central London	-0.50	-1.25	-0.50	-2.20
24	Essex and Kent	-1.28	-1.37	-0.91	-1.90
25	Oxfordshire, Surrey and Sussex	-0.66	-1.56	-0.60	-2.24
26	Somerset and Wessex	-0.83	-1.72	-0.64	-2.86
27	West Devon and Cornwall	-0.83	-2.15	-0.66	-3.87

5.2 Locational Changes

Table 19 shows the change in (£/kW) due to just the locational element, i.e. with the generator residual removed. These locational changes mirror the relative changes between zones in Figure 1.

Table 19 – Locational Changes in Generation Tariffs under Current Methodology (£/kW)

Zone	Zone Name	Change 14/15 to 15/16	Change 15/16 to 16/17	Change 16/17 to 17/18	Change 17/18 to 18/19
1	North Scotland	-0.47	9.56	1.37	0.51
2	East Aberdeenshire	-0.10	9.82	1.29	1.44
3	Western Highlands	-2.99	9.76	1.33	0.17
4	Skye and Lochalsh	-2.98	9.94	1.50	-8.17
5	Eastern Grampian and Tayside	-0.28	9.97	1.31	0.59
6	Central Grampian	0.77	10.61	1.33	0.09
7	Argyll	1.84	11.09	1.35	-0.37
8	The Trossachs	1.02	10.93	1.25	-0.15
9	Stirlingshire and Fife	0.58	10.12	0.96	-0.77
10	South West Scotland	1.01	12.20	0.96	-0.81
11	Lothian and Borders	0.49	7.38	0.85	-0.31
12	Solway and Cheviot	0.41	5.85	0.83	-1.28
13	North East England	0.04	2.22	0.35	0.25
14	North Lancs and The Lakes	0.11	0.16	0.14	-0.40
15	South Lancs, Yorks and Humber	-0.04	-0.87	0.15	-0.69
16	North Midlands and North Wales	-0.12	-2.28	-0.07	-0.91
17	South Lincs and North Norfolk	-0.37	-1.40	-0.01	-1.12
18	Mid Wales and The Midlands	-0.23	-1.86	-0.10	-0.84
19	Anglesey and Snowdon	0.03	-4.32	-0.16	0.00
20	Pembrokeshire	-0.08	-2.03	-0.03	-2.38
21	South Wales	0.11	-2.19	-0.19	-3.00
22	Cotswold	-0.10	-2.22	-0.25	-2.45
23	Central London	-0.16	-1.81	-0.32	-1.29
24	Essex and Kent	-0.93	-1.93	-0.73	-0.99
25	Oxfordshire, Surrey and Sussex	-0.32	-2.12	-0.42	-1.33
26	Somerset and Wessex	-0.48	-2.28	-0.46	-1.95
27	West Devon and Cornwall	-0.48	-2.71	-0.48	-2.96

- 2014/15 to 2015/16 locational changes are discussed in the April view of TNUoS tariffs for 2015/16.
- The completion of the Western HVDC link in 2016/17 has a major impact on locational tariffs in 2016/17 due to the higher unit cost. Appendix B shows 2016/17 Generation TNUoS tariffs without the HVDC link and a correspondingly smaller change from 2015/16 to 2016/17.
- **Zone 10** shows an increase in tariff from 2015/16 to 2016/17 over and above that from the HVDC link due to around 180MW of new connections.
- **Zone 4,** which contains a single generator, shows a decrease in tariff in 2018/19 caused by reversing of power flow on a long radial spur. The power exported by this generator now reduces flows along this circuit, whereas previously it added to them, resulting in a lower tariff. The change in power flows arises from a combination of factors including local demand changes and Generation increases throughout GB.
- Northern Scotland tariffs increase in 2018/19 due to around 1500MW of offshore wind farms connecting. This increases North to South flows which decreases southern tariffs other than

in those zones with large TEC increase such as **Zone 19** (Codling Park Wind Farm 1000MW) and **Zone 23** and **Zone 24** (Belgium Interconnector 1000MW, Gateway Energy Centre 1000MW)

- This new Generation also changes the direction of flows on a number of circuits around Longannet the major generator in **Zone 9.** This reduces the locational tariff in this zone
- Inflation of the Expansion Constant will also tend to increase tariffs in the North and decrease tariffs in the South.

5.3 Changes in the Generator Residual

The Residual element of the Generation charge is affected by the following variables

- Generation and Demand split – Discussed in Section 7.
- Revenue assumptions – Discussed in Section 4.5.
- Generation charging base - As the Generation charging base increases from year to year the Generation residual decreases. The increase in the generator charging base is described in Section 4.3. The calculation of generator residuals is described in Section 7.

5.4 Onshore Local Circuit Tariffs

A forecast of onshore local circuit tariffs from 2015/16 to 2018/19 is contained in Appendix F. These have been calculated using contracted Generation under the Current Methodology. For later years where there is limited information on how the generator intends to connect to the system, Generation has been mapped to the nearest existing node. This will alter the forecast Local Circuit Tariff. If you are unsure about your local circuit tariff or whether one will be applied please contact your Connection Account Manager or alternatively use the contact details in Section 10.

5.5 Onshore Local Substation Tariffs

Table 20 shows the onshore local substation tariffs that apply during 2014/15. These tariffs only apply to transmission connected generators. The tariffs will be indexed by RPI for each year of the price control. For this forecast we have used an increase of 3% each year.

If no significant work is planned at a substation that changes whether or not there is redundancy, the tariff will only alter by RPI. If the sum of the TEC of the generators at a substation changes such that the 1320MW threshold is crossed, this will change the tariff applied to all generators at that location beyond the normal RPI increase. If you are unsure about what tariff may apply please contact National Grid for further information.

Table 20 – 2015/16 Local Substation Tariffs (£/kW)

Sum of TEC at connecting Substation	Connection Type	132kV	275kV	400kV
<1320 MW	No redundancy	0.181	0.103	0.075
<1320 MW	Redundancy	0.398	0.246	0.179
>=1320 MW	No redundancy	-	0.324	0.234
>=1320 MW	Redundancy	-	0.532	0.389

5.6 Small Generators Discount

Under Condition C13 of National Grid's electricity transmission licence a discount is applied to small generators connected to 132kV transmission systems who, but for the fact they are connected to a transmission system, would not otherwise be liable for TNUoS charges. The discount is shown in Table 21 under current methodology and Diversity 1. Table 25 shows the impact on demand tariffs. Please note that this licence condition, and therefore the discount, will lapse on 1 April 2016 unless replaced with an alternative requirement but we have included its effect in future demand tariff forecasts.

Table 21 – Small Generators Discount

Small Generators Discount		14/15	15/16	16/17	17/18	18/19
Current Methodology	(£/kW)	8.96	9.37	10.48	10.81	11.76
Diversity 1	(£/kW)		9.57	10.75	11.11	12.05

6. Commentary on Forecast Demand Tariffs – Current Methodology

6.1 Half-Hourly Demand Tariffs (£/kW)

Figure 2 illustrates the forecast TNUoS tariffs set out in Section 3.3 for Half-Hour (HH) metered demand under current methodology. Table 22 shows the year on year change in HH TNUoS tariffs.

Figure 2

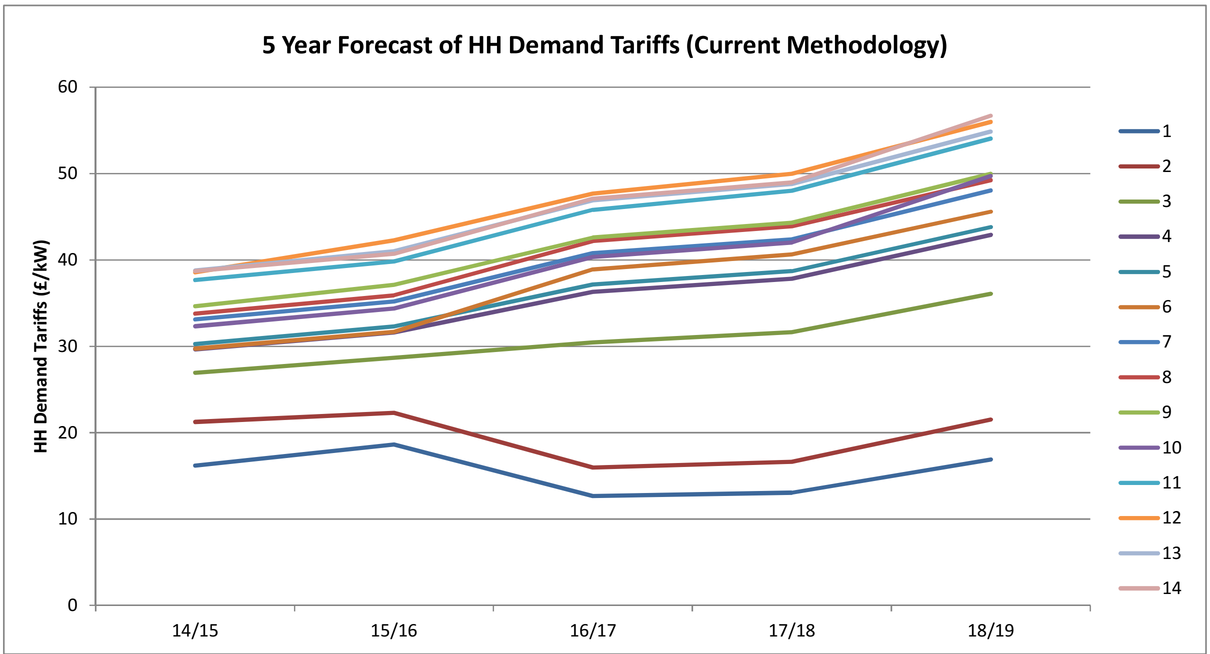

Table 22 – Changes in Half-Hourly Metered Tariffs under Current Methodology (£/kW)

Zone	Zone Name	Change 14/15 to 15/16	Change 15/16 to 16/17	Change 16/17 to 17/18	Change 17/18 to 18/19
1	Northern Scotland	2.44	-5.94	0.38	3.84
2	Southern Scotland	1.05	-6.33	0.66	4.89
3	Northern	1.74	1.77	1.20	4.43
4	North West	1.98	4.67	1.54	5.07
5	Yorkshire	2.04	4.85	1.54	5.12
6	N Wales & Mersey	1.96	7.24	1.71	4.96
7	East Midlands	2.07	5.61	1.60	5.67
8	Midlands	2.12	6.28	1.69	5.35
9	Eastern	2.46	5.50	1.73	5.63
10	South Wales	2.04	5.99	1.68	7.69
11	South East	2.18	5.97	2.20	6.03
12	London	3.70	5.41	2.31	6.01
13	Southern	2.24	5.88	1.90	6.05
14	South Western	2.01	6.38	1.91	7.71

6.2 Non Half-Hourly Demand Tariffs (p/kWh)

Figure 3 illustrates the forecast TNUoS tariffs set out in Section 3.3 for Non Half-Hour (NHH) metered demand under current methodology.

Table 23 shows the year on year change in NHH TNUoS tariffs.

Figure 3

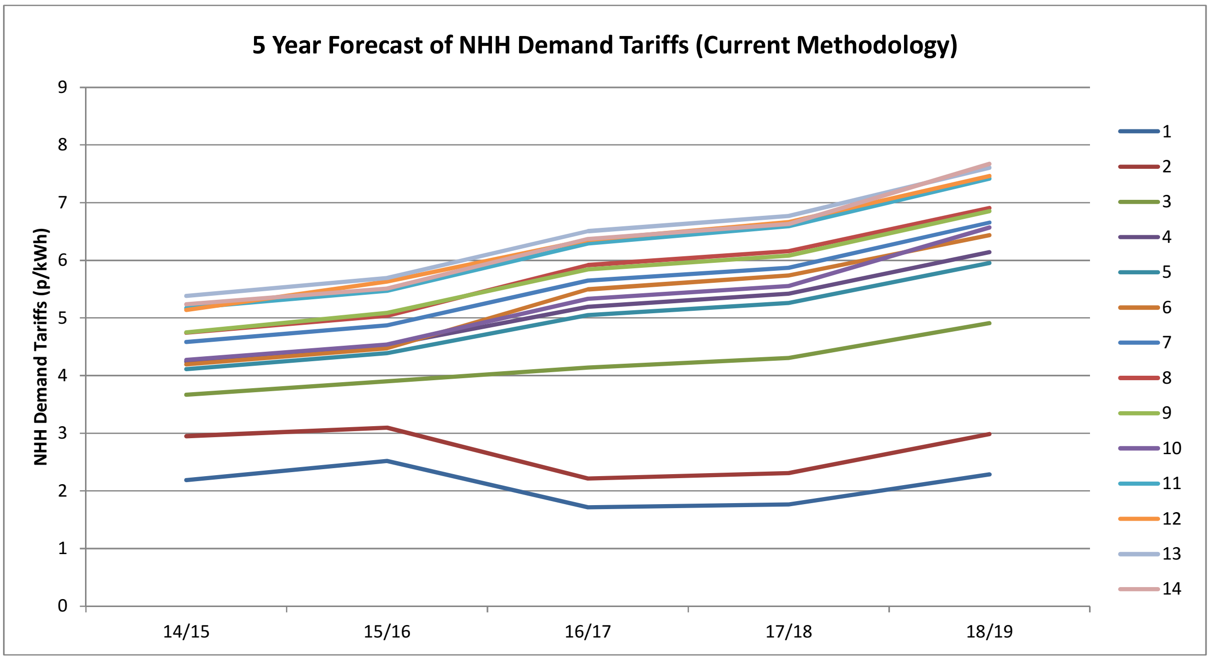

Table 23 – Changes in Non Half-Hourly Metered Tariffs under Current Methodology (£/kWh)

Zone	Zone Name	Change 14/15 to 15/16	Change 15/16 to 16/17	Change 16/17 to 17/18	Change 17/18 to 18/19
1	Northern Scotland	0.33	-0.80	0.05	0.52
2	Southern Scotland	0.15	-0.88	0.09	0.68
3	Northern	0.24	0.24	0.16	0.60
4	North West	0.28	0.67	0.22	0.73
5	Yorkshire	0.28	0.66	0.21	0.70
6	N Wales & Mersey	0.28	1.02	0.24	0.70
7	East Midlands	0.29	0.78	0.22	0.79
8	Midlands	0.30	0.88	0.24	0.75
9	Eastern	0.34	0.75	0.24	0.77
10	South Wales	0.27	0.79	0.22	1.02
11	South East	0.30	0.82	0.30	0.83
12	London	0.49	0.72	0.31	0.80
13	Southern	0.31	0.82	0.26	0.84
14	South Western	0.27	0.86	0.26	1.04

6.3 Locational Changes

Table 24 shows the change in the HH tariff due to just the locational element, i.e. with the demand residual removed. These locational changes mirror the relative changes between zones in Figure 2.

Table 24 – Locational Changes in Demand Tariffs under Current Methodology (£/kW)

Zone	Zone Name	Change 14/15 to 15/16	Change 15/16 to 16/17	Change 16/17 to 17/18	Change 17/18 to 18/19
1	Northern Scotland	0.47	-9.81	-1.14	-0.85
2	Southern Scotland	-0.92	-10.20	-0.85	0.20
3	Northern	-0.24	-2.10	-0.32	-0.26
4	North West	0.01	0.80	0.03	0.37
5	Yorkshire	0.07	0.99	0.03	0.42
6	N Wales & Mersey	-0.01	3.38	0.19	0.26
7	East Midlands	0.10	1.75	0.08	0.98
8	Midlands	0.15	2.42	0.17	0.66
9	Eastern	0.49	1.64	0.22	0.94
10	South Wales	0.07	2.13	0.16	3.00
11	South East	0.21	2.11	0.69	1.34
12	London	1.73	1.54	0.80	1.32
13	Southern	0.27	2.01	0.39	1.36
14	South Western	0.03	2.52	0.39	3.02

- 2014/15 to 2015/16 locational changes are discussed in the April view of TNUoS tariffs for 2015/16.
- The HVDC link decreases tariffs in Scotland and the North and increases tariffs in the South in 2016/17. These changes are the reverse of what is happening with Generation tariffs
- Increased Generation in Scotland and inflation of the expansion constant decreases tariffs in **Zones 1 & 2** in 2017/18.
- Demand tariffs in **Zone 10** (South Wales) increase in 2018/19 due to changing circuit flows due to new Generation in the North of Wales and in the North.
- North to south flows decrease tariffs in the North and increase tariffs in the South. These changes are compounded by the expansion constant

6.4 Residual Demand Changes

The Residual element of the Generation charge is affected by the following variables:

- Generation and Demand split – discussed in Section 7.
- Revenue assumptions - Discussed in Section 4.5.
- Demand charging base

The demand charging base has been kept constant across the years. This assumes a peak system demand of 55.3GW; HH demand at triad of 15.9GW; and chargeable NHH demand of 28.6TWh[9]. National Grid will continue to review the demand charging base and update as required.

The information in Section 7 can be used to alter the demand charging base and see the effect on the residual.

6.5 Small Generators Discount

Under Condition C13 of National Grid's electricity transmission licence a discount is applied to small generators connected to 132kV transmission systems who, but for the fact they are connected to a transmission system, would not otherwise be liable for TNUoS charges. The cost of the discount has been added to the residual element of demand tariff. Table 25 shows what has been added under Current and Diversity 1 methodologies. Please note that this licence condition, and therefore this addition to the residual element, is due to lapse on 1 April 2016 unless replaced with an alternative requirement.

Table 25 – Demand Tariff Residual to Recover the Small Generators Discount

		14/15	15/16	16/17	17/18	18/19
Current Methodology	(£/kW)	0.26	0.26	0.25	0.25	0.28
	(p/kWh)	0.04	0.04	0.03	0.03	0.04
Diversity 1	(£/kW)		0.26	0.29	0.30	0.33
	(p/kWh)		0.04	0.04	0.04	0.05

[9] TNUoS charges for NHH demand is based on annual energy consumption between 4pm and 7pm.

7. Proportion of Revenue recovered from Generation and Demand

Current charging methodology fixes the proportion of revenue collected from Generation (G) at 0.27 and the proportion from Demand (D) at 0.73. The tariffs in this document are calculated using the current charging methodology proportions of 0.27 and 0.73.

EU Regulation ECR 838/2010 limits the revenue that can be recovered from Generation to an average of €2.5/MWh per annum. With rising revenues, this limit is forecast to be reached in 2015/16. CUSC Modification Proposal CMP224 would alter the G/D ratio to keep revenue recovered from Generation within the Regulation. The original proposal for CMP224 modifies the G/D ratio to meet a limit of €2.34/MWh which includes a 7% risk margin for exchange rate and demand fluctuations. Other proposals include higher risk margins. Please note that this modification is still pending and also that ACER published an opinion on 15 April 2014 that may affect this limit.

The proportions of TNUoS revenue to be recovered from Generation (G) and from Demand (D) are given by the formulas:

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

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

Where:

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

Table 26 shows how the G and D proportions could vary under the original CMP224 proposal. As the limit is reached from 2015/16 any increases in revenue are recovered from demand resulting in an increase in D and reduction in G. Tariffs using these adjusted proportions for Generation and Demand are contained in Appendix C.

Table 26 – Calculation of Generator and Demand Revenue Proportions

	2014/15*	2015/16	2016/17	2017/18	2018/19
G	0.27	0.24	0.21	0.19	0.17
D	0.73	0.76	0.79	0.81	0.83
E (TWh)	322	319	316	311	307
L (€/MWh)	2.5	2.34	2.34	2.34	2.34
R (£m)	2477.3	2,644.7	2984.1	3110.4	3535.6
X (€/£)	1.2	1.2	1.2	1.2	1.2

*2014/15 proportions are fixed as tariffs have already been set

8. Generation and Demand Residuals

This section shows how to calculate the residual element of tariffs. This can be used to assess the effect of changing the assumptions in our tariff forecasts without the need to run the DCLF model.

The residual elements of the generator and Demand TNUoS tariffs are given by the formulas:

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

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

Where:

- R_G is the Generation residual tariff (£/kW)
- R_D is the Demand residual tariff (£/kW)
- G is the proportion of TNUoS revenue recovered from Generation (See Section 7)
- D is the proportion of TNUoS revenue recovered from Demand (See Section 7)
- R is the total TNUoS revenue to be recovered (£m)
- Z_G is the TNUoS revenue recovered from Generation locational zonal tariffs (£m)
- Z_D is the TNUoS revenue recovered from Demand locational zonal tariffs (£m)
- O is the TNUoS revenue recovered from offshore local tariffs (£m)
- L_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)

$\mathbf{Z_G}$, $\mathbf{Z_D}$ and $\mathbf{L_G}$ are determined by locational tariffs so will change depending on whether the current methodology or Diversity 1 methodology is used.

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

Table 27 shows the Residuals for each charging year with locational revenues calculated using the current Methodology. Table 28 shows the residuals for each charging year with location revenues calculated using the Diversity 1 methodology.

Table 27 – Calculation of Residuals under Current Methodology

	2014/15	2015/16	2016/17	2017/18	2018/19
R_G (£/kW)	8.42	5.46	6.02	5.84	4.93
R_D (£/kW)	30.04	32.02	35.89	37.40	42.09
G	0.27	0.27	0.27	0.27	0.27
D	0.73	0.73	0.73	0.73	0.73
R (£m)	2,477.3	2,644.7	2,984.1	3,110.4	3,535.6
Z_G (£m)	54.0	59.1	71.7	74.8	93.6
Z_D (£m)	147.0	159.8	193.9	202.3	253.2
O (£m)	160.0	207.3	218.7	241.9	362.4
L_G (£m)	- 160.0	35.3	41.4	44.5	50.4
B_G (£m)	73.0	75.5	78.7	81.9	90.9
B_D (£m)	55.3	55.3	55.3	55.3	55.3

Table 28 – Calculation of Residuals under Diversity 1

	2015/16	2016/17	2017/18	2018/19
R_G (£/kW)	3.21	3.29	3.07	1.13
R_D (£/kW)	35.08	39.71	41.39	47.08
G	0.27	0.27	0.27	0.27
D	0.73	0.73	0.73	0.73
R (£m)	2,644.7	2,984.1	3,110.4	3,535.6
Z_G (£m)	228.8	287.7	300.7	437.5
Z_D (£m)	- 9.4	- 17.4	- 18.2	- 22.6
O (£m)	207.3	218.7	241.9	362.4
L_G (£m)	35.8	40.5	46.0	51.5
B_G (£m)	75.5	78.7	81.9	90.9
B_D (£m)	55.3	55.3	55.3	55.3

9. Tools and Supporting Information

9.1 Discussing Tariff Changes

National Grid is keen to ensure that customers understand the current charging arrangements and the reasons why charges have changed from year to year. Therefore, we expect to attend a future charging methodology forum to discuss these forecasts

9.2 Future Updates to Tariff Forecasts

Noting these uncertainties and our desire to provide timely and accurate information on the future path of tariffs, National Grid will update the forecast of 2015/16 tariffs throughout 2014 according to the timetable below:

31 July 2014 2nd update of forecast tariffs for 2015/16

3 October 2014 3rd update of forecast tariffs for 2015/16

24 December 2014 Draft tariffs for 2015/16

30 January 2015 Final tariffs for 2015/16

This will allow customers to gauge the impact of changes to the key inputs into the charging model such as TEC reductions and allowed revenue ahead of the publication of draft and final TNUoS tariffs.

9.3 Charging Models

Customers can receive a copy of National Grid's charging models to conduct sensitivity analysis on alternative developments of Generation and Demand. These models are 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 National Grid's view as it may be based on commercially sensitive information.

If you would like a copy of any of the models please contact the National Grid. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

9.4 Tools and Useful Guides

National Grid has prepared a number of tools and guidance notes to help customers understand the charging arrangements. These include:

- Indicative 2015/16 CMP213 Diversity 1 Tariff Calculator
- Draft Annual Load Factors 2014-15
- Offshore Charging Guidance

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Tools-and-Data/

10. Comments & Feedback

As part of our commitment to customers, National Grid welcomes comments and feedback on the information contained in this document. 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:

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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

Appendices

Appendix A: Treatment of HVDC Links

Appendix B: 2016/17 TNUoS Tariffs without the Western HVDC Link

Appendix C: TNUoS Tariffs with Altered G/D Split

Appendix D: Contracted Generation Changes from 15/16 to 18/19

Appendix E : Zonal Summaries of Modelled Demand

Appendix F: Onshore Local Circuit Tariffs

Appendix G: Generation Zone Map

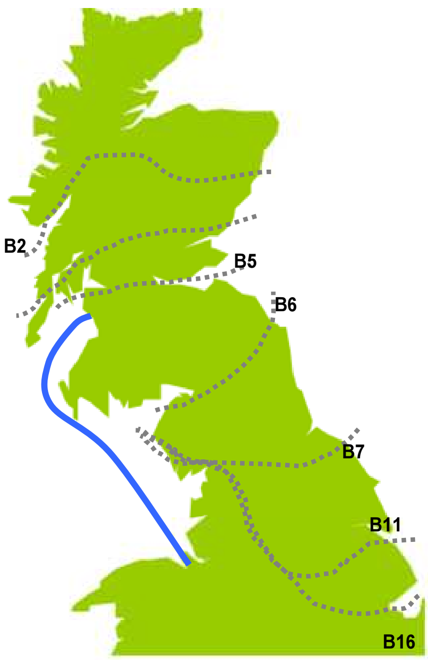
Appendix A: Treatment of HVDC Links

A number of undersea High Voltage Direct Current (HVDC) circuits are currently being developed that will parallel the MITS (Main Integrated Transmission System), the first of which is planned to be introduced in 2016/17.

Due to the nature of this technology, the flow on each of these links would be selectively controlled by the SO rather than determined by the impedance of the circuit. The flow determined by the SO will depend upon operational conditions at the time, and the resulting decision will take a range of factors in account.

As TNUoS tariffs will vary depending on the flow assumed in the transport model, an algorithm has been proposed under CMP213 that will objectively determine the desired flow on the HVDC link. This is then used to set the impedance of each HVDC link within the transport model. Whilst a range of options were considered by the CMP213 Workgroup, only one of these options was taken forward as part of the proposed solution and its alternatives. The following example explains how this algorithm is applied.

Example: Determining the desired flow on a HVDC link



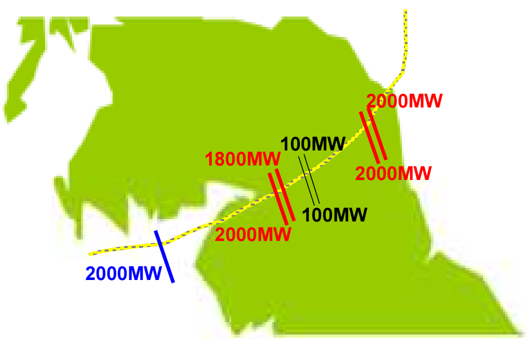
The adjacent diagram depicts a HVDC link connecting the transmission network in Southwest Scotland to that in North Wales. In doing so the link crosses multiple transmission constraint boundaries (B6, B7, B11, and B16).

The first step is to determine the flows across each boundary with no flow present on the HVDC link (the base boundary flow).

The desired flow on the link for each boundary in turn is then determined as the same proportion of the base boundary flow as the proportion of additional boundary capacity added by the link.

The final desired flow for the link is then determined as the average of the desired flows on the link for each boundary.

For the purposes of the example, running the transport model without flows on the HVDC element of the network results in boundary flows of: 6,000MW over the B6; 7,000MW over the B7; 10,000 over the B11; and 15,000MW over the B16.



The adjacent diagram shows the circuits on the B6 constraint boundary and their capacities. The total capacity of the B6 is 10,000MW, 2,000MW of which relates to the HVDC link (shown in blue). As the HVDC link makes up 20% of the B6 boundary capacity, the desired B6 boundary flow on the

HVDC link will be 1,200MW (20% of the B6 base boundary flow (6000MW)).

Similarly, the following table provides the desired boundary flows on the HVDC link on each boundary, based on an example set of boundary assumptions:

Boundary	**Total Capacity (MW)**	**HVDC Capacity (MW)**	**HVDC Capacity Proportion**	**Base Boundary Flow (MW)**	**Desired Boundary flow on HVDC link (MW)**
B6	10,000	2,000	20%	6,000	1,200
B7	14,000	2,000	14.3%	7,000	1,000
B11	25,000	2,000	8.0%	10,000	800
B16	30,000	2,000	6.7%	15,000	1,000

The overall desired flow on the link is determined by taking the average of the desired boundary flow on the HVDC link. In this case the desired flow on the link is 1,000MW. Following this calculation, an iterative process is undertaken in the transport model to determine the impedance required to result in the desired flow on the HVDC link.

Whilst this example provides the process for determining the desired flow on a single HVDC link, the procedure to determine the flow on multiple links is identical. For example if a second 2,000MW HVDC link crossed the B6 boundary, the desired boundary flow on each link would be calculated as 1,000MW. This is equal to the proportion of the base boundary flow (unchanged at 6,000MW) multiplied by the proportion of capacity on each link (2,000MW) to the total boundary capacity (now 12,000MW).

Appendix B: 2016/17 TNUoS Tariffs without the Western HVDC Link

This section shows the impact on tariffs in 2016/17 if the Western HVDC link is not included in the circuit model.

Table 29 - 2016/17 Generation Tariffs under Current Methodology without the Western HVDC Link

Zone	Zone Name	16/17 (£/kW)
1	North Scotland	27.56
2	East Aberdeenshire	23.44
3	Western Highlands	25.98
4	Skye and Lochalsh	31.62
5	Eastern Grampian and Tayside	24.37
6	Central Grampian	23.49
7	Argyll	23.74
8	The Trossachs	20.29
9	Stirlingshire and Fife	19.00
10	South West Scotland	18.44
11	Lothian and Borders	15.11
12	Solway and Cheviot	13.93
13	North East England	10.21
14	North Lancs and The Lakes	9.70
15	South Lancs, Yorks and Humber	7.95
16	North Midlands and North Wales	6.32
17	South Lincs and North Norfolk	4.37
18	Mid Wales and The Midlands	3.48
19	Anglesey and Snowdon	8.97
20	Pembrokeshire	6.60
21	South Wales	3.84
22	Cotswold	0.54
23	Central London	-3.95
24	Essex and Kent	0.35
25	Oxfordshire, Surrey and Sussex	-1.34
26	Somerset and Wessex	-3.47
27	West Devon and Cornwall	-5.86

Table 30 - 2016/17 Demand Tariffs under Current Methodology without the Western HVDC Link

Zone	Zone Name	HH Tariffs 16/17 (£/kW)	NHH Tariffs 16/17 (p/kWh)
1	Northern Scotland	22.66	3.07
2	Southern Scotland	26.19	3.64
3	Northern	32.94	4.48
4	North West	35.91	5.14
5	Yorkshire	36.65	4.98
6	N Wales & Mersey	35.97	5.08
7	East Midlands	39.63	5.49
8	Midlands	40.33	5.66
9	Eastern	41.67	5.72
10	South Wales	38.96	5.15
11	South East	44.73	6.14
12	London	46.64	6.22
13	Southern	45.71	6.34
14	South Western	45.78	6.20

Table 31 - 2016/17 Generation Tariffs under Diversity 1 Methodology without the Western HVDC Link

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.89	12.45	7.91	3.79	23.31	15.44
2	East Aberdeenshire	3.58	7.49	7.91	3.79	20.52	13.95
3	Western Highlands	3.02	11.29	7.53	3.79	22.25	14.71
4	Skye and Lochalsh	-1.02	11.29	9.12	3.79	19.80	16.30
5	Eastern Grampian and Tayside	2.87	10.23	6.91	3.79	20.74	13.78
6	Central Grampian	4.37	10.08	6.77	3.79	21.99	13.59
7	Argyll	3.36	8.42	8.57	3.79	21.61	14.89
8	The Trossachs	3.39	8.42	5.25	3.79	18.33	11.57
9	Stirlingshire and Fife	3.88	7.74	4.92	3.79	18.01	11.04
10	South West Scotland	2.56	9.60	4.92	3.79	17.99	11.59
11	Lothian and Borders	2.47	9.60	0.37	3.79	13.35	7.04
12	Solway and Cheviot	1.66	6.00	3.36	3.79	13.01	8.95
13	North East England	2.93	3.51	1.14	3.79	10.32	5.99
14	North Lancashire and The Lakes	1.36	3.51	2.13	3.79	9.74	6.98
15	South Lancashire, Yorkshire and Humber	3.78	1.38		3.79	8.54	4.21
16	North Midlands and North Wales	3.25	0.44		3.79	7.36	3.93
17	South Lincolnshire and North Norfolk	0.81	0.81		3.79	5.17	4.04
18	Mid Wales and The Midlands	1.01	0.24		3.79	4.97	3.87
19	Anglesey and Snowdon	4.10	2.30		3.79	9.51	4.48
20	Pembrokeshire	8.23	-3.87		3.79	9.32	2.63
21	South Wales & Gloucester	5.85	-4.04		3.79	6.82	2.58
22	Cotswold	2.56	1.68	-5.68	3.79	1.85	-1.39
23	Central London	-2.77	1.68	-4.84	3.79	-2.64	-0.54
24	Essex and Kent	-4.28	1.68		3.79	0.69	4.30
25	Oxfordshire, Surrey and Sussex	-1.51	-2.41		3.79	0.60	3.07
26	Somerset and Wessex	-1.78	-4.13		3.79	-0.88	2.55
27	West Devon and Cornwall	-1.28	-6.27		3.79	-1.87	1.91

Table 32 - 2016/17 Demand Tariffs Under Diversity 1 Methodology without the Western HVDC Link

Zone No.	Zone Name.	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	25.00	3.39
2	Southern Scotland	26.21	3.64
3	Northern	32.84	4.47
4	North West	35.82	5.13
5	Yorkshire	36.62	4.98
6	N Wales & Mersey	35.84	5.06
7	East Midlands	39.61	5.49
8	Midlands	40.12	5.63
9	Eastern	41.89	5.75
10	South Wales	38.28	5.06
11	South East	45.20	6.21
12	London	47.20	6.29
13	Southern	45.68	6.34
14	South Western	44.89	6.08

Appendix C: TNUoS Tariffs with Altered G/D Split

As described in Section 4.4, EU Regulation ECR 838/2010 limits the amount that can be recovered from Generation to an average of €2.5/MWh per annum. CUSC Modification Proposal CMP224 is currently under consideration which would alter the residual elements of Demand and Generation tariffs.

This section contains tariffs under both current and Diversity 1 methodologies to demonstrate the impact of applying a limit to generation tariffs of €2.34/MWh. The €2.34/MWh limit includes a 7% risk margin in line with the original CMP224 proposal. The limit reduces the proportion of TNUoS revenues collected from Generation and increases the proportion collected from Demand. The calculation of these proportions and the resulting impact on the residual element of tariffs is contained in Section 7. Under an alternative proposal for CMP224, an error margin of around 14% could be used. For information we recommend reviewing the CMP224 reports on the CUSC modifications website[10].

The altered proportions for G and D used in these tariffs are:

	2014/15	2015/16	2016/17	2017/18	2018/19
G	0.27	0.24	0.21	0.19	0.17
D	0.73	0.76	0.79	0.81	0.83

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

Generation Tariffs – Current Methodology – Altered G/D Split

Table 33 – Generation Tariffs under Current Methodology with Altered G/D Split

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	North Scotland	27.68	25.81	34.71	35.14	33.89
2	East Aberdeenshire	22.97	21.48	30.63	30.98	30.66
3	Western Highlands	28.35	23.97	33.06	33.44	31.85
4	Skye and Lochalsh	33.79	29.42	38.69	39.25	29.31
5	Eastern Grampian and Tayside	24.02	22.35	31.66	32.03	30.86
6	Central Grampian	21.97	21.35	31.29	31.68	30.00
7	Argyll	20.85	21.29	31.72	32.12	29.99
8	The Trossachs	18.42	18.04	28.31	28.61	26.70
9	Stirlingshire and Fife	18.02	17.20	26.66	26.69	24.15
10	South West Scotland	16.46	16.07	27.60	27.62	25.05
11	Lothian and Borders	14.18	13.28	19.99	19.90	17.83
12	Solway and Cheviot	12.73	11.74	16.92	16.81	13.76
13	North East England	9.87	8.51	10.07	9.48	7.96
14	North Lancs and The Lakes	9.15	7.86	7.36	6.56	4.40
15	South Lancs, Yorks and Humber	7.61	6.17	4.64	3.84	1.39
16	North Midlands and North Wales	6.17	4.65	1.71	0.69	-1.99
17	South Lincs and North Norfolk	4.65	2.88	0.81	-0.14	-3.02
18	Mid Wales and The Midlands	3.55	1.92	-0.60	-1.64	-4.24
19	Anglesey and Snowdon	8.57	7.21	2.22	1.12	-0.65
20	Pembrokeshire	6.55	5.08	2.39	1.42	-2.73
21	South Wales	3.78	2.49	-0.36	-1.49	-6.26
22	Cotswold	0.75	-0.75	-3.64	-4.82	-9.04
23	Central London	-3.78	-5.33	-7.80	-9.07	-12.12
24	Essex and Kent	1.43	-0.89	-3.49	-5.16	-7.91
25	Oxfordshire, Surrey and Sussex	-0.83	-2.55	-5.33	-6.69	-9.78
26	Somerset and Wessex	-2.71	-4.58	-7.53	-8.93	-12.64
27	West Devon and Cornwall	-4.70	-6.58	-9.95	-11.37	-16.09

Generation Tariffs – Diversity 1 – Altered G/D Split

Under the proposed CMP213 Diversity 1 methodology, the tariff paid by a generator depends on the zone into which the generator connects; whether or not the generator is conventional or intermittent; and the generator's specific annual load factor. It is built up from four tariff elements as follows:

- **System Peak:** Payable by conventional generators only
- **Shared Year Round:** Payable by all generators scaled by each generator's specific annual load factor
- **Not Shared Year Round**: Payable by all
- **Residual:** Payable by all

To illustrate the combined effect of these elements we have included examples of the tariff that would be paid by:

- A conventional generator with an annual load factor of 70%
- An intermittent generator with an annual load factor of 30%.

Table 34 – 2015/16 Generation Tariffs under Diversity 1 with altered G/D Split

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.91	13.71	6.21	2.16	20.87	12.48
2	East Aberdeenshire	3.88	8.07	6.21	2.16	17.89	10.79
3	Western Highlands	2.95	11.99	6.01	2.16	19.51	11.76
4	Skye and Lochalsh	-2.64	11.99	5.88	2.16	13.79	11.63
5	Eastern Grampian and Tayside	2.56	10.92	5.66	2.16	18.01	11.09
6	Central Grampian	4.44	10.46	5.40	2.16	19.31	10.69
7	Argyll	3.59	8.44	7.59	2.16	19.24	12.28
8	The Trossachs	3.66	8.44	4.16	2.16	15.88	8.85
9	Stirlingshire and Fife	3.86	7.88	4.00	2.16	15.53	8.52
10	South West Scotland	2.89	9.32	4.00	2.16	15.57	8.95
11	Lothian and Borders	3.00	9.32	0.06	2.16	11.73	5.01
12	Solway and Cheviot	1.60	5.63	2.77	2.16	10.47	6.61
13	North East England	3.23	3.11	1.09	2.16	8.66	4.18
14	North Lancashire and The Lakes	1.70	3.11	1.81	2.16	7.84	4.90
15	South Lancashire, Yorkshire and Humber	3.97	0.93		2.16	6.77	2.43
16	North Midlands and North Wales	3.54	-0.09		2.16	5.64	2.13
17	South Lincolnshire and North Norfolk	1.92	-0.44		2.16	3.77	2.02
18	Mid Wales and The Midlands	1.32	-0.35		2.16	3.23	2.05
19	Anglesey and Snowdon	4.95	1.18		2.16	7.93	2.51
20	Pembrokeshire	7.84	-3.49		2.16	7.56	1.11
21	South Wales & Gloucester	5.38	-3.51		2.16	5.08	1.10
22	Cotswold	2.13	2.17	-5.57	2.16	0.24	-2.76
23	Central London	-3.99	2.17	-4.86	2.16	-5.19	-2.06
24	Essex and Kent	-4.62	2.17		2.16	-0.95	2.81
25	Oxfordshire, Surrey and Sussex	-1.83	-2.08		2.16	-1.13	1.53
26	Somerset and Wessex	-2.01	-3.29		2.16	-2.16	1.17
27	West Devon and Cornwall	-0.04	-3.92		2.16	-0.63	0.98

Table 35 – 2016/17 Generation Tariffs under Diversity 1 with Altered G/D Split

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	1.97	18.68	11.95	1.01	28.01	18.56
2	East Aberdeenshire	2.73	13.42	11.95	1.01	25.08	16.98
3	Western Highlands	2.07	17.52	11.57	1.01	26.91	17.84
4	Skye and Lochalsh	-1.98	17.52	13.16	1.01	24.47	19.43
5	Eastern Grampian and Tayside	2.05	16.38	10.90	1.01	25.43	16.83
6	Central Grampian	3.88	16.35	10.88	1.01	27.21	16.80
7	Argyll	2.97	14.73	12.69	1.01	26.98	18.12
8	The Trossachs	3.04	14.73	9.38	1.01	23.74	14.81
9	Stirlingshire and Fife	3.04	13.80	8.93	1.01	22.64	14.09
10	South West Scotland	2.79	16.79	8.93	1.01	24.49	14.98
11	Lothian and Borders	2.53	16.79	0.50	1.01	15.79	6.54
12	Solway and Cheviot	1.52	9.27	5.67	1.01	14.69	9.46
13	North East England	3.02	4.06	3.10	1.01	9.98	5.34
14	North Lancashire and The Lakes	1.41	4.06	2.12	1.01	7.38	4.35
15	South Lancashire, Yorkshire and Humber	3.87	0.97		1.01	5.57	1.30
16	North Midlands and North Wales	3.22	-1.03		1.01	3.52	0.70
17	South Lincolnshire and North Norfolk	0.92	0.16	0.00	1.01	2.04	1.06
18	Mid Wales and The Midlands	1.06	-0.82		1.01	1.50	0.77
19	Anglesey and Snowdon	3.53	-0.62		1.01	4.11	0.82
20	Pembrokeshire	8.22	-5.01		1.01	5.72	-0.49
21	South Wales & Gloucester	5.85	-5.17		1.01	3.24	-0.54
22	Cotswold	2.56	0.81	-5.92	1.01	-1.78	-4.67
23	Central London	-2.70	0.81	-4.84	1.01	-5.97	-3.59
24	Essex and Kent	-4.21	0.81		1.01	-2.63	1.25
25	Oxfordshire, Surrey and Sussex	-1.46	-3.39		1.01	-2.82	-0.01
26	Somerset and Wessex	-1.75	-5.17		1.01	-4.36	-0.54
27	West Devon and Cornwall	-1.26	-7.33		1.01	-5.37	-1.19

Table 36 - 2017/18 Generation Tariffs under Diversity 1 with altered G/D Split

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	3.09	16.89	12.61	0.03	27.56	17.71
2	East Aberdeenshire	3.81	11.36	12.61	0.03	24.40	16.05
3	Western Highlands	3.20	15.55	12.09	0.03	26.20	16.79
4	Skye and Lochalsh	-0.97	15.55	13.74	0.03	23.68	18.44
5	Eastern Grampian and Tayside	3.13	14.45	11.40	0.03	24.67	15.76
6	Central Grampian	5.00	14.35	11.31	0.03	26.39	15.65
7	Argyll	4.12	12.68	13.10	0.03	26.12	16.93
8	The Trossachs	4.18	12.68	9.67	0.03	22.75	13.50
9	Stirlingshire and Fife	4.15	11.79	9.22	0.03	21.65	12.78
10	South West Scotland	3.99	14.27	9.22	0.03	23.22	13.53
11	Lothian and Borders	3.56	14.27	1.86	0.03	15.44	6.17
12	Solway and Cheviot	2.34	7.73	5.59	0.03	13.37	7.94
13	North East England	3.30	3.76	3.13	0.03	9.09	4.28
14	North Lancashire and The Lakes	3.06	3.76	0.70	0.03	6.42	1.86
15	South Lancashire, Yorkshire and Humber	4.20	1.03		0.03	4.95	0.34
16	North Midlands and North Wales	3.98	-1.12		0.03	3.23	-0.31
17	South Lincolnshire and North Norfolk	1.40	0.02	0.00	0.03	1.45	0.03
18	Mid Wales and The Midlands	1.45	-0.78		0.03	0.94	-0.21
19	Anglesey and Snowdon	7.04	-3.83		0.03	4.39	-1.12
20	Pembrokeshire	6.99	-3.78		0.03	4.37	-1.10
21	South Wales & Gloucester	4.28	-3.94		0.03	1.55	-1.15
22	Cotswold	0.93	1.58	-5.52	0.03	-3.45	-5.01
23	Central London	-5.24	1.58	-5.12	0.03	-9.23	-4.62
24	Essex and Kent	-4.72	1.58		0.03	-3.58	0.50
25	Oxfordshire, Surrey and Sussex	-2.53	-1.88		0.03	-3.81	-0.53
26	Somerset and Wessex	-3.25	-3.92		0.03	-5.97	-1.15
27	West Devon and Cornwall	-2.80	-6.16		0.03	-7.08	-1.82

Table 37 - 2018/19 Generation Tariffs under Diversity 1 with Altered G/D Split

Generation Tariffs		System Peak	Shared Year Round	Not Shared Year Round	Residual	70% Load Factor Conventional	30% Load Factor Intermittent
Zone	Zone Name	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)	Tariff (£/kW)
1	North Scotland	2.09	14.25	20.66	-2.75	29.97	22.18
2	East Aberdeenshire	1.60	11.89	19.54	-2.75	26.71	20.35
3	Western Highlands	2.61	13.59	19.28	-2.75	28.64	20.60
4	Skye and Lochalsh	-1.69	13.59	21.05	-2.75	26.11	22.37
5	Eastern Grampian and Tayside	3.77	13.08	17.95	-2.75	28.13	19.12
6	Central Grampian	3.38	12.86	17.28	-2.75	26.90	18.38
7	Argyll	2.71	12.23	18.67	-2.75	27.18	19.58
8	The Trossachs	2.71	12.23	15.37	-2.75	23.88	16.28
9	Stirlingshire and Fife	2.47	11.41	13.92	-2.75	21.62	14.59
10	South West Scotland	2.97	12.60	14.21	-2.75	23.25	15.23
11	Lothian and Borders	2.60	12.60	6.40	-2.75	15.07	7.42
12	Solway and Cheviot	2.17	7.20	8.24	-2.75	12.69	7.65
13	North East England	3.38	3.89	4.37	-2.75	7.72	2.78
14	North Lancashire and The Lakes	1.53	3.89	2.89	-2.75	4.39	1.31
15	South Lancashire, Yorkshire and Humber	4.03	1.21		-2.75	2.12	-2.39
16	North Midlands and North Wales	3.12	-0.97		-2.75	-0.32	-3.05
17	South Lincolnshire and North Norfolk	2.57	-1.64		-2.75	-1.34	-3.25
18	Mid Wales and The Midlands	1.04	-0.99		-2.75	-2.41	-3.05
19	Anglesey and Snowdon	1.93	1.27		-2.75	0.06	-2.37
20	Pembrokeshire	8.32	-5.82		-2.75	1.49	-4.50
21	South Wales & Gloucester	5.47	-6.24		-2.75	-1.65	-4.63
22	Cotswold	2.25	0.50	-6.57	-2.75	-6.73	-9.17
23	Central London	-3.11	0.50	-5.03	-2.75	-10.55	-7.64
24	Essex and Kent	-3.54	0.50		-2.75	-5.95	-2.61
25	Oxfordshire, Surrey and Sussex	-1.22	-3.72		-2.75	-6.58	-3.87
26	Somerset and Wessex	-1.94	-6.01		-2.75	-8.91	-4.56
27	West Devon and Cornwall	-1.47	-8.27		-2.75	-10.02	-5.24

Demand Tariffs – Current Methodology – Altered G/D Split

The following tariffs are based on current methodology with the proposed methodology under CMP213 WACM2 for HVDC cables from 2016/17 onwards as described in section 4.2.

Table 38 – Half Hour Demand Tariffs under Current Methodology with Altered G/D Split (£/kW)

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	Northern Scotland	16.17	20.05	15.91	17.56	23.30
2	Southern Scotland	21.24	23.72	19.20	21.12	27.91
3	Northern	26.94	30.11	33.68	36.14	42.48
4	North West	29.64	33.06	39.53	42.34	49.31
5	Yorkshire	30.25	33.73	40.38	43.19	50.21
6	N Wales & Mersey	29.72	33.11	42.16	45.14	51.99
7	East Midlands	33.10	36.61	44.03	46.89	54.46
8	Midlands	33.78	37.34	45.43	48.38	55.63
9	Eastern	34.63	38.53	45.83	48.83	56.36
10	South Wales	32.32	35.80	43.60	46.54	56.13
11	South East	37.66	41.28	49.05	52.52	60.45
12	London	38.55	43.69	50.90	54.48	62.39
13	Southern	38.79	42.46	50.14	53.31	61.26
14	South Western	38.70	42.14	50.33	53.50	63.11

Table 39 – Non Half-Hour Demand Tariffs under Current Methodology with Altered G/S Split (p/kWh)

Zone	Zone Name	14/15	15/16	16/17	17/18	18/19
1	Northern Scotland	2.19	2.71	2.15	2.38	3.15
2	Southern Scotland	2.95	3.30	2.67	2.94	3.88
3	Northern	3.67	4.10	4.58	4.92	5.78
4	North West	4.24	4.73	5.66	6.06	7.06
5	Yorkshire	4.11	4.59	5.49	5.87	6.83
6	N Wales & Mersey	4.20	4.68	5.95	6.37	7.34
7	East Midlands	4.58	5.07	6.10	6.49	7.54
8	Midlands	4.74	5.24	6.37	6.79	7.80
9	Eastern	4.75	5.29	6.29	6.70	7.73
10	South Wales	4.27	4.73	5.76	6.15	7.42
11	South East	5.17	5.67	6.73	7.21	8.30
12	London	5.14	5.82	6.79	7.26	8.32
13	Southern	5.38	5.89	6.96	7.40	8.50
14	South Western	5.24	5.70	6.81	7.24	8.54

Demand Tariffs – Diversity 1 – Altered G/D Split

The following tariffs have been calculated using the Diversity 1 methodology which forms part of CMP213 WACM 2

Table 40 – Half-Hour Demand Tariffs under Diversity 1 with Altered G/D Split (£/kW)

Zone	Zone Name	15/16	16/17	17/18	18/19
1	Northern Scotland	22.59	19.23	22.69	24.95
2	Southern Scotland	23.86	20.34	23.87	28.43
3	Northern	29.88	33.69	36.63	42.68
4	North West	32.96	39.39	42.37	49.46
5	Yorkshire	33.65	40.29	43.08	50.39
6	N Wales & Mersey	32.96	41.78	44.61	52.06
7	East Midlands	36.54	43.89	46.51	54.63
8	Midlands	37.09	45.05	48.06	55.89
9	Eastern	38.74	45.96	48.62	56.57
10	South Wales	35.10	42.78	45.97	54.59
11	South East	41.80	49.41	52.23	60.50
12	London	44.52	51.35	54.48	62.64
13	Southern	42.15	50.00	52.80	61.25
14	South Western	40.57	49.32	52.70	61.38

Table 41 – Non Half-Hour Demand Tariffs under Diversity 1 with Altered G/D Split (p/kWh)

Zone	Zone Name	15/16	16/17	17/18	18/19
1	Northern Scotland	3.06	2.60	3.07	3.38
2	Southern Scotland	3.31	2.83	3.32	3.95
3	Northern	4.07	4.58	4.98	5.81
4	North West	4.72	5.64	6.07	7.08
5	Yorkshire	4.58	5.48	5.86	6.85
6	N Wales & Mersey	4.65	5.90	6.30	7.35
7	East Midlands	5.06	6.08	6.44	7.57
8	Midlands	5.20	6.32	6.74	7.84
9	Eastern	5.32	6.31	6.67	7.76
10	South Wales	4.64	5.65	6.07	7.21
11	South East	5.74	6.78	7.17	8.31
12	London	5.93	6.85	7.26	8.35
13	Southern	5.85	6.94	7.32	8.50
14	South Western	5.49	6.67	7.13	8.31

Appendix D: Contracted Generation Changes from 15/16 to 18/19

The tables below indicate the contracted Generation changes for the following years. Actual contracted Generation may differ from the year in question due to TEC reductions of current Generation and delays/terminations of new connections.

Table 42 - 2015/16 TEC Changes

Power Station	Zone	TEC Change (MW)
Dumnaglass Wind Farm	1	98.5
Corriegarth	1	69
Aberdeen Bay Wind Farm	5	77
Cour	7	23
Kilgallioch	10	274
Brockloch Rig Wind Farm	10	75
Dersalloch	10	69
Afton	10	68
Clyde (North)	11	117
Aikengall II Windfarm	11	108
Harelaw	11	80
Blacklaw Extension	11	69
Clyde (South)	11	54
Andershaw Wind Farm	11	35
Strathy North and South Wind	12	226
Harestanes	12	20
Lynemouth Power Station	13	366
Race Bank Wind Farm	17	500
Abernedd Power Station	21	500
Barry Power Station	21	93
Rampion	25	332
	Total	**3,253.5**

Table 43 - 2016/17 Contracted TEC Changes

Power Station	Zone	TEC Change (MW)
Eishken Estate, Isle of Lewis	1	133
Blackcraig Wind Farm	1	57.5
Corriemoillie Wind Farm	1	47.5
Margree	1	42.5
Lewis Wave Generating Station	1	3
Millennium South	3	25
Griffin Wind Farm	5	15.4
Galloper	18	340
Pencloe	10	63
Glen App Windfarm	10	32.2
Ulzieside	10	30
Whiteside Hill	10	27
Neart na Goaithe Offshore Wind Farm	11	450
Crystal Rig 2	11	62
Rowantree Wind Farm	11	60
Galawhistle Wind Farm	11	55.2
Harestanes	12	17.3
Newfield Wind Farm	12	52.5
Ewe Hill	12	18
Tees Renewable Energy Plant	13	280
Walney Extension Power Station A Offshore Wind Farm	14	330
Walney Extension Power Station B Offshore Wind Farm	14	330
Hornsea Offshore Wind Farm - Platform 1A	15	500
Hornsea Offshore Wind Farm - Platform 1B	15	500
C.Gen Killingholme North Power Station	15	490
Hatfield Power Station	16	800
Keadby II	16	710
Trafford Power - Stage 1	16	570
Burbo Bank Extension Offshore Wind Farm	16	254
Docking Shoal Wind Farm	17	500
Dudgeon Offshore Wind Farm	17	400
Drakelow	18	1320
South Hook CHP Plant	20	490
Rhigos	21	228
Damhead Creek II	24	1200

London Array Stage 5	24	204
Rampion	25	332
	Total	**10,969.1**

Table 44 - 2017/18 Contracted TEC Changes

Power Station	Zone	TEC Change (MW)
Dorenell Wind Farm	1	220
Aultmore Wind Farm	1	39
Loch Hill Wind Farm	1	27
Beatrice Wind Farm	1	20
Allt Duine Wind Farm	1	10
Earlshaugh Wind Farm	9	55
Auchencrosh (Interconnector CCT)	10	-215
Inch Cape Offshore Wind Farm	11	330
Ewe Hill	12	48
Dogger Bank Platform 1A	15	500
Dogger Bank Platform 2A	15	500
Hornsea Offshore Wind Farm - Platform 2A	15	500
Thorpe Marsh	16	1200
Kings Lynn B	17	981
Spalding Energy Expansion	17	920
Barking Power Station C	18	470
Celtic Array Platform 1	19	500
Greenwire Wind Farm - Pembroke	20	2000
Irish Bridge Tranche 1 - Pembroke	20	1000
Gateway Energy Centre Power Station	24	1000
Navitus Bay Offshore Wind Project Platform 1	26	400
	Total	**10,505**

Table 45 - 2018/19 Contracted TEC Changes

Power Station	Zone	TEC Change (MW)
Beatrice Wind Farm	1	380
Allt Duine Wind Farm	1	77
Viking Wind Farm	1	412
MeyGen Tidal	1	222
Costa Head, Westray South and Brough Head Phase 1	1	130
Loch Urr	1	84
Tom Na Clach	1	75
Benbrack & Quantans Hill	1	72
Sallachy Wind Farm	1	66
Glen Kyllachy Wind Farm	1	48.5
Duncansby Tidal Array	1	30
Spittal Hill Wind Farm	1	21
Marwick Head Wave Farm	1	9
Moray Firth Offshore Wind Farm	2	780
Stronelairg	3	241.2
Glenmorie Windfarm	3	114
Crossburns Wind Farm	5	99
Firth of Forth Offshore Wind Farm 1A	9	545
Firth of Forth Offshore Wind Farm 1B	9	530
Glen App Windfarm	10	51
South Kyle	10	165
Windy Standard III Wind Farm	10	43.5
Millenderdale Wind Farm	10	21
Inch Cape Offshore Wind Farm	11	360
Dogger Bank Platform 2B	13	500
Dogger Bank Platform 3A	13	500
Knottingley Power Station	15	1500
Dogger Bank Platform 1B	15	500
Hornsea Offshore Wind Farm - Platform 2B	15	500
Marex	16	1500
Trafford Power - Stage 2	16	950
Triton Knoll Offshore Wind Farm	16	200
East Anglia ONE (Offshore Wind Farm 1A)	18	600
East Anglia ONE (Offshore Wind Farm 1B)	18	600
Codling Park Wind Farm	19	1000

Greenwire Wind Farm - Pentir	19	1000
Celtic Array Platform 2	19	500
Abernedd Power Station	21	414
Belgium Interconnector	24	1000
Navitus Bay Offshore Wind Project Platform 2	26	400
Irish Bridge Tranche 2 - Alverdiscott	27	1400
Atlantic Array	27	300
		17,940.2

Appendix E : Zonal Summaries of Modelled Demand

Table 46 - Zonal Summaries of Modelled Demand

Zone	Zone Name	2014/15	Change from 14/15 to 15/16	2015/16	Change from 15/16 to 16/17	2016/17	Change from 16/17 to 17/18	2017/18	Change from 17/18 to 18/19	2018/19
1	Northern Scotland	882	-8	874	-17	856	7	864	-3	860
2	Southern Scotland	3,770	-70	3,700	10	3,709	1	3,710	1	3,711
3	Northern	2,939	-19	2,921	16	2,937	15	2,952	13	2,965
4	North West	4,011	80	4,091	60	4,152	43	4,194	35	4,229
5	Yorkshire	4,787	77	4,864	25	4,889	27	4,916	26	4,942
6	N Wales & Mersey	2,546	142	2,688	11	2,699	10	2,709	11	2,721
7	East Midlands	5,188	81	5,269	32	5,301	49	5,349	30	5,379
8	Midlands	4,808	-296	4,512	16	4,528	8	4,536	16	4,551
9	Eastern	6,693	-488	6,205	63	6,268	67	6,335	55	6,390
10	South Wales	2,120	-126	1,993	1	1,995	1	1,995	1	1,996
11	South East	3,883	-33	3,851	31	3,882	11	3,893	12	3,905
12	London	5,944	-455	5,489	26	5,515	118	5,632	97	5,730
13	Southern	6,236	-40	6,195	84	6,279	63	6,342	66	6,408
14	South Western	2,810	111	2,922	13	2,935	13	2,948	22	2,969
	Total	56,617	-1,044	55,574	370	55,944	432	56,376	381	56,757

Appendix F : Onshore Local Circuit Tariffs

2014/15 onshore local circuit tariffs have been set using current methodology. 2015/16 onshore local circuit tariffs are as per the April updated view using current methodology. 2016/17 to 2018/19 onshore local circuit tariffs are based on Diversity 1 methodology.

Table 47 – Local Circuit Tariffs (£/kW)

Node No.	Substation	14/15	15/16	16/17	17/18	18/19
1	Aberdeen Bay		0.82	0.85	0.87	0.90
2	Achruach	3.02	2.43	3.52	3.62	3.73
3	Afton		3.66	3.77	3.88	4.00
4	Aigas	0.57	0.59	0.61	0.62	0.64
5	Aikengall II		1.10	1.09	1.12	1.15
6	An Suidhe	0.00	-0.29	1.86	1.92	1.97
7	Arecleoch	0.27	0.28	1.91	1.97	2.03
8	Aultmore				1.92	1.98
9	Baglan Bay	0.57	0.64	0.66	0.63	0.65
10	Black Craig			1.80	1.85	1.91
11	Black Law	0.87	0.90	0.93	0.96	0.98
12	Blacklaw Extension		2.16	2.04	2.10	2.16
13	Bodelwyddan	-0.02	-0.02	0.10	0.11	0.11
14	Brochloch		3.37	2.41	3.67	3.78
15	Carraig Gheal	3.85	3.96	4.08	4.20	4.33
16	Carrington	0.13	0.06	0.06	0.07	0.07
17	Clyde (North)	0.10	0.10	0.10	0.10	0.11
18	Clyde (South)	0.11	0.11	0.12	0.12	0.12
19	Coalburn			0.02	0.03	0.03
20	Corriegarth		2.28	2.35	2.42	2.49
21	Corriemoillie	2.40	2.48	2.55	2.63	2.71
22	Coryton	0.05	0.32	0.33	0.34	-0.22
23	Cour		0.41	0.42	0.44	0.45
24	Cruachan	1.67	1.72	1.77	1.82	1.88
25	Crystal Rig	0.36	-0.01	-0.06	-0.05	-0.06
26	Culligran	1.52	1.56	1.61	1.66	1.71
27	Deanie	2.49	2.56	2.64	2.72	2.80
28	Dersalloch	1.60	1.65	1.70	1.75	1.80
29	Didcot	0.22	0.22	0.47	0.50	0.51
30	Dinorwig	2.10	2.16	2.23	2.30	2.37
31	Dudgeon			11.29	11.63	11.98
32	Dumnaglass			1.79	1.84	1.89
33	Earlshaugh				2.27	2.34
34	Edinbane	5.98	6.16	6.35	6.54	6.73
35	Ewe Hill	2.27	2.33	2.23	2.29	2.36
36	Fallago	0.95	0.07	-0.01	-0.01	-0.01
37	Farr Windfarm	2.05	2.00	2.05	2.13	6.60
38	Ffestiniogg	0.22	0.23	0.24	0.24	0.25
39	Finlarig	0.28	0.29	0.30	0.31	0.32
40	Foyers	0.67	0.69	0.71	0.73	0.75
41	Glendoe	1.61	1.66	1.71	1.76	1.81
42	Glenmoriston	1.15	1.19	1.23	1.26	1.30
43	Gordonbush	3.44	2.19	2.26	0.65	0.76
44	Griffin Wind	1.39	1.68	1.73	5.75	5.92

Node No.	Substation	14/15	15/16	16/17	17/18	18/19
45	Hadyard Hill	2.41	2.48	2.56	2.63	2.71
46	Harestanes	4.43	4.80	4.90	5.05	5.20
47	Hartlepool	0.52	0.54	0.56	0.58	0.59
48	Hedon	0.17	0.17	0.17	0.17	0.18
49	Hornsea			0.02	0.03	0.03
50	Invergarry	1.24	-0.62	-0.64	-0.65	-0.67
51	Kendoon North					
52	Kilbraur	1.70	1.95	2.01	0.40	0.47
53	Killgallioch		-4.16	4.28	4.41	4.54
54	Killingholme	0.48	0.27			
55	Kilmorack	0.17	0.18	0.18	0.19	0.19
56	Langage	0.58	0.59	0.61	0.63	0.65
57	Lochay	0.32	0.33	0.34	0.35	0.36
58	Luichart	0.99	1.02	1.05	1.09	1.12
59	Marchwood	0.33	0.34	0.35	0.37	0.38
60	Margree			2.77	2.86	2.94
61	Mark Hill	-0.77	-0.79	0.81	0.84	0.86
62	Millennium Wind	1.42	1.46	1.51	1.55	1.60
63	Mossford	3.47	3.57	3.68	3.79	3.90
64	Mucking Flats				-0.17	-0.18
65	Nant	2.19	-1.11	-1.14	-1.17	-1.21
66	Neilston		0.79	0.81	0.84	0.86
67	Newfield			6.26	6.45	6.64
68	Quoich	3.79		4.01	4.13	4.25
69	Rhigos			0.11	0.12	0.12
70	Rocksavage	0.02	0.02	0.02	0.02	0.02
71	Rowantree			1.92	1.98	2.04
72	Sallachy					
73	Saltend	0.30	0.30	0.32	0.33	0.33
74	South Humber Bank	0.74	0.76	0.38	0.39	0.41
75	Spalding	0.27	0.27	0.25	0.26	0.27
76	Strathy Wind		3.87	3.99	5.50	5.34
77	Whitelee	0.09	0.10	0.10	0.10	0.10
78	Whitelee Extension	0.26	0.27	0.27	0.28	0.29

Appendix G: Generation Zone Map