RIIO-ED1 RIGs Environment and Innovation Commentary, version 3.0

2016-2017

Electricity North West Limited

Contents

Summary – Information Required

One Commentary document is required per DNO Group. Respondents should ensure that comments are clearly marked to show whether they relate to all the DNOs in the group or to which DNO they relate.

Commentary is required in response to specific questions included in this document. DNO's may include supporting documentation where they consider it necessary to support their comments or where it may aid Ofgem's understanding. Please highlight in this document if additional information is provided.

The purpose of this commentary is to provide the opportunity for DNOs to set out further supporting information related to the data provided in the Environment and Innovation Reporting Pack. It also sets out supporting data submissions that DNOs must provide to us.

Worksheet by worksheet commentary

At a worksheet by worksheet level there is one standard question to address, where appropriate, as follows:

- **Allocation and estimation methodologies**: DNOs should detail estimates, allocations or apportionments used in reaching the numbers submitted in the worksheets.

  This is required for all individual worksheets (ie not an aggregate level), where relevant. Not all tables will have used allocation or estimation methods to reach the numbers. Where this is the case simply note "NA".

  Note: this concerns the methodology and assumptions and not about the systems in place to check their accuracy (that is for the NetDAR). This need to be completed for all worksheets, where an allocation or estimation technique was used.

In addition to the standard commentary questions, some questions specific to each worksheet are asked.

E1 – Visual Amenity

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
All expenditure on Electricity North West Limited projects is allocated on a percentage basis to a series of investment drivers. Allocations are calculated by Project Managers based on the respective costs of project deliverables. Volumes are also recorded on projects in a way that indicates the driver. Undergrounding for Visual Amenity is identified as a separate driver and specific projects are raised for these schemes of work.

Explanation of the increase or decrease in the total length of OHL inside designated areas for reasons other than those recorded in worksheet E1. For example, due to the expansion of an existing, or creation of a new, Designated Area.
In 2016-17 there was an expansion of the Lake District and Yorkshire Dales National Parks by 70 km^2 and 417km^2 respectively; https://www.gov.uk/government/publications/national-parks-extensions-to-the-lake-district-and-yorkshire-dales-parks This increased the reported length of lines within these Designated Areas in 2016-17 onwards. The entirety of both of these increases lies within our operating region.

E2 – Environmental Reporting

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
All expenditure on Electricity North West Limited projects is allocated on a percentage basis to a series of investment drivers including environment. Cost allocations are calculated by Project Managers based on the respective costs of project deliverables. Volumes are also recorded on projects in a way that indicates the driver. Environmental investment is identified as a separate driver within the classification system with asscociated costs and volumes allocated accordingly. **Fluid Filled Cables** To calculate the Oil In Service (Cell AI22), the following estimations are used: ➢ 33kV single core cable = 1 560 litres per km ➢ 33kV three core cable = 1 300 litre per km ➢ 33kV cable = 1.1835 tanks per km ➢ 33kV average volume per tank of 173.525 litres ➢ 30km only of 33kV single core cable ➢ 132kV single core cable = 4 800 litres per km ➢ 132kV three core cable = 4 000 litre per km ➢ 132kV cable = 1.7605 tanks per km

- 132kV average volume per tank of 337.985 litres
- 44km only of 132kV single core cable

In 2016-17 we removed in total 10.476km of 33kV and 0.137km of 132kV oil-filled cable from service. Due to a data cleansing exercise we identified a further 88km of 33kv oil filled cable in service.

DNOs must provide some analysis of any emerging trends in the environmental data and any areas of trade-off in performance.
No significant emerging trends were identified in terms of environmental data.

Where reported in the Regulatory Year under report, DNOs must provide discussion of the nature of any complaints relating to Noise Pollution and the nature of associated measures undertaken to resolve them.
30 noise complaints were received in the year all of which related to substation noise. No payments to customers made in relation to any of the complaints received.

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
Investment in this area in 2016-17 comprised minor substation civil works i.e. fencing replacement and switchgear replacement and ecology surveys on transmission towers. In such cases the additional investment is presented on this table together with a volume. It should be noted that the volumes reported are a count of the number of sites at which such work has been completed rather than a length in km.

Any Undergrounding for Visual Amenity should be identified including details of the activity location, including whether it falls within a Designated Area.
No additional undergrounding for visual amenity outside of the scheme described in table E1 was undertaken in 2016-17.

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any reportable incidents or prosecutions associated with any of the activities reported in the worksheet.
N/A.

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any Environmental Management System (EMS) certified under ISO or other recognised accreditation scheme.
Electricity North West Limited is certificated to the ISO 14001 Environmental Management System Standard and successfully retained its certification in 2016-17. In addition Electricity North West Limited obtained certification to the ISO 50001 Energy Management Systems Standard in 2016-17.

DNOs must provide a brief description of any permitting, licensing, registrations and permissions, etc related to the activities reported in this worksheet that you have purchased or obtained during the Regulatory Year.
N/A.

DNOs must include a description of any SF6 and Oil Pollution Mitigation Schemes undertaken in the Regulatory Year including the cost and benefit implications and how these were assessed.
No SF6 mitigation schemes were undertaken in 2016-17. Sixteen oil mitigation schemes undertaken relating to reinforcement works at Woolfold Primary substation; replacement of transformers at Poulton, Barton, Queens Park, Ulverston, Keswick and Kirkby Stephen substations; overlay of an oil filled cable on the Kearsley-Bury-Radcliffe 132kV circuit; replacement of switchgear at Keswick; and replacement of an LV cable at Caton.

E3 –BCF

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
To calculate buildings electricity usage we use data provided by the business energy suppliers and/or landlords for whole buildings or parts of buildings that we occupy. Within this data some estimates for energy usage have been made by where half hourly metering is not installed. To calculate substation electricity usage we use data provided by the business energy suppliers for metered supplies and the estimated consumption figure as submitted in the unmetered MPAN certificate. Within the metered data, some estimates for energy usage have been made by where half hourly metering is not installed and all of the unmetered supplies are estimates. To calculate the London Underground element of rail journey distances nominal mileages were used for unspecified Zone 1, 2 and 3+ journeys based on typical locations visited by our staff. Zone 1 journeys were taken to be a three miles one-way, Zone 2, six miles one-way and Zone 3, nine miles one-way.

To calculate the fugitive emissions from air conditioning units an estimated leakage rate is taken from Table 8B in Annex 8 of the *2012 Guidelines to Defra/DECC's GHG Conversion Factors for Company Reporting*. To determine which leakage rate applies, the units were compared with the sizing guide in the December 2011 ICF document *Development of the GHG Refrigeration and Air Conditioning Model Final Report*. All units were judged to be "Small Stationary Air Conditioning" units. The time used by each unit was calculated as 24% of time available in the year based on an assumed usage of eight hours per day, five days per week = 40 hours per week/168 hours in week= 24%.

The reported losses figure is a snapshot of received data as of the date of this report and will change as further settlement reconciliation runs are carried out (up to 28 months after each relevant settlement date).

BCF reporting boundary and apportionment factor

DNOs that are part of a larger corporate group must provide a brief introduction outlining the structure of the group, detailing which organisations are considered within the reporting boundary for the purpose of BCF reporting.

Any apportionment of emissions across a corporate group to the DNO business units must be explained and, where the method for apportionment differs from the method proposed in the worksheet guidance, justified.

N/A.

BCF process

The reporting methodology for BCF must be compliant with the principles of the Greenhouse Gas Protocol.[1] Accounting approaches, inventory boundary and calculation methodology must be applied consistently over time. Where any processes are improved with time, DNOs should provide an explanation and assessment of the potential impact of the changes.

N/A.

[1] Greenhouse gas protocol

Commentary required for each category of BCF

For **each** category of BCF in the worksheet (i.e. Business Energy Usage, Operation Transport etc) DNOs must, where applicable, provide a description of the following information, ideally at the same level of granularity as the Defra conversion factors:

- the methodology used to calculate the values, outlining and explaining any specific assumptions or deviations from the Greenhouse Gas Protocol
- the data source and collection process
- the source of the emission conversion factor (this shall be Defra unless there is a compelling case for using another conversion factor. Justification should be included for any deviation from Defra factors.)
- the Scope of the emissions i.e., Scope 1, 2 or 3
- whether the emissions have been measured or estimated and, if estimated the assumptions used and a description of the degree of estimation
- any decisions to exclude any sources of emissions, including any fugitive emissions which have not been calculated or estimated
- any tools used in the calculation
- where multiple conversion factors are required to calculate BCF (e.g., due to use of both diesel and petrol vehicles), DNOs should describe their methodology in commentary
- where multiple units are required for calculation of volumes in a given BCF category (e.g., a mixture of mileage and fuel volume for transport), DNOs should describe their methodology in commentary, including the relevant physical units, e.g. miles.

DNOs may provide any other relevant information here on BCF, such as commentary on the change in BCF, and should ensure the baseline year for reference in any description of targets or changes in BCF is the Regulatory Year 2014-15. DNOs should make clear any differences in the commentary that relate to DNO and contractor emissions.

DNO Emissions: Buildings Energy usage - Buildings Electricity

The buildings-electricity energy usage figure is calculated using the kWh usage data provided by the business energy suppliers and/or landlords for whole buildings or parts of buildings that we occupy.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	UK electricity	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 2	**Version:**	1.0	**Year:**	2016

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2016	0.41205

For 2016/17 the calculation is as follows:

- Consumption = 5 558 635.96 kWh x 0.41205 / 1 000 = 2290.44 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.00041205 (cell AZ14) was used:

- Total consumption 2016/17 = 5 558 635.96 kWh (cell BP14) x 0.00041205 = 2 290.44 (cell AE14).

DNO Emissions: Buildings Energy Usage - Substation Electricity

The substation electricity usage data is calculated from kWh usage data provided by the business energy suppliers for metered supplies and the estimated consumption figure as submitted in the unmetered MPAN certificate.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	UK electricity	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 2	**Version:**	1.0	**Year:**	2016

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2016	0.41205

For 2016/17 the calculation is as follows:

- Consumption = 15 299 999.85 kWh x 0.41205 / 1 000 = 6 304.36 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.00041205 (cell AZ16) was used:

- Total consumption 2016/17 = 15 299 999.85 kWh (cell BP16) x 0.00041205 = 6 304.36 (cell AE16).

DNO Emissions: Operational Transport – Road

The operational transport figure is calculated from fuel litres purchased data provided by the business fuel card suppliers. All the operational vehicles that we own have diesel engines.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Fuels	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Diesel (average bio fuel blend)	litres	2.61163

For 2016/17 the calculation is as follows:

- Consumption = 1 355 941.00 litres x 2.61163 / 1 000 = 3 541.22 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.00261163 (cell AZ22) was used:

- Total consumption 2016/17 = 1 355 941.00 litres (cell BP22) x = 0.00261163 = 3 541.21 (cell AE22).

DNO Emissions: Business Transport – Road

The business transport figure for road travel is calculated from the mileages claimed back through the corporate expenses system.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Business travel- land	Expiry:	31/06/2017	Factor set:	Full set
Scope:	Scope 3	Version:	1.0	Year:	2016

			Diesel	Petrol
Activity	Type	Unit	kg CO_2e	kg CO_2e
Cars (by size)	Small car	miles	0.23618	0.25794
	Medium car	miles	0.28551	0.32241
	Large car	miles	0.36166	0.47414

For 2016/17 the calculation is as follows:

- Small petrol car: 283 506.00 miles x 0.25794 / 1 000 = 73.13 tCO2e.
- Medium petrol car: 373 691.00 miles x 0.32241 / 1 000 = 120.48 tCO2e.
- Large petrol car: 75 516.00 miles x 0.47414 / 1 000 = 35.81 tCO2e.
- Small diesel car: 767 785.00 miles x 0.23618 / 1 000 = 181.34 tCO2e.
- Medium diesel car: 1 596 264.00 miles x 0.28551 / 1 000 = 455.75 tCO2e.
- Large diesel car: 1 007 082.00 miles x 0.36166 / 1 000 = 364.22 tCO2e.

This gives a total of 1 230.72 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 0.00029989444 (cell AZ31) was used:

- Total consumption 2016/17 = 4 103 844.00 miles (cell BP31) x 0.00029989444 = 1 230.72 (cell AE31).

DNO Emissions: Business Transport – Rail

The business transport figure for rail is calculated using details provided by our travel supplier of rail journeys undertaken by our employees. The journey details are split into those travelled on national rail and London Underground and then the mileages for each journey calculated using the distances between stations published on the Network Rail website. The mileages are then converted into kilometres for calculating the tCO_2e.

For London Underground journeys, nominal mileages were used for unspecified Zone 1, 2 and 3+ journeys based on typical locations visited by our staff. Zone 1 journeys were taken to be a 3 miles one-way, Zone 2, 6 miles one-way and Zone 3, 9 miles one-way.

Excluded from the rail journey calculations are any journeys booked by employees directly and claimed back through the corporate expenses system as these are minimal and the details not specific enough to make a valid calculation.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Business travel- land	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 3	**Version:**	1.0	**Year:**	2016

Activity	Type	Unit	kg CO_2e
Rail	National rail	passenger.km	0.04885
	London Underground	passenger.km	0.05789

For 2016/17 the calculation is as follows:

- National Rail: 389 408.76 km x 0.04885 / 1 000 = 19.02 tCO2e.
- London Underground: 3 123.19 km x 0.05789 / 1 000 = 0.18 tCO2e.

This gives a total of 19.20 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 0.00004891321 (cell AZ32) was used:

- Total consumption 2016/17 = 392 531.95 km (cell BP32) x 0.00004891321 = 19.20 (cell AE32).

DNO Emissions: Business Transport – Air

The business transport figure for air travel is calculated using details provided by our travel supplier of air journeys undertaken by our employees. The journey details are split into domestic, short haul international and long haul international and the kilometres travelled for each journey calculated using the air journey distance calculator on the www.webflyer.com website.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Business travel (air)	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 3	**Version:**	1.0	**Year:**	2016

				With RF
Activity	Haul	Class	Unit	kg CO_2e
Flights	Domestic, to/from UK	Average passenger	passenger.km	0.27867
	Short-haul, to/from UK	Economy class	passenger.km	0.16508
	Long-haul, to/from UK	Business class	passenger.km	0.42565

For 2016/17 the calculation is as follows:

- Domestic, to/from UK, average passenger: 19 400.00 km x 0.27867 / 1 000 = 5.41tCO2e.
- Short-haul, to/from UK, economy class: 344 399.00 km x 0.16508 / 1 000 = 56.85 tCO2e.
- Long-haul, to/from UK, business class: 49 140.00 km x 0.42565 / 1 000 = 20.92 tCO2e.

This gives a total of 83.17 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 0.00020141428 (cell AZ34) was used:

- Total consumption 2016/17 = 412 930.00 km (cell BP34) x 0.00020141428 = 83.17 (cell AE34).

DNO Emissions: Fugitive Emissions - SF6

The amount of sulphur hexafluoride (SF_6) emitted is calculated using the actual mass of SF_6 used when topping up or replacing distribution network apparatus with low gas or gas loss. The top-up amounts are the actual amounts recorded by the engineers on-site when topping up. The loss amounts for apparatus that has been replaced as a result of gas loss are the amounts of gas held by those units.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Refrigerant & other	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Emission	Unit	kg CO_2e
Kyoto protocol - standard	Sulphur hexafluoride (SF6)	kg	22800

For 2016/17 the calculation is as follows:

- 0.05523 tonnes x 22 800 = 1 259.24 tCO2e

To ensure this figure was the 2017 entry in table E3 a scalar of 22.80 (cell AZ40) was used:

- Total emissions 2016/17 = 55.23 kg (cell BP40) x 22.80 = 1 259.24 (cell AE40).

DNO Emissions: Fugitive Emissions - Gases Other

The "gases other" figure is calculated using data held on the capacity and type of HFC gases contained in air conditioning units in use within our occupied offices.

An estimated leakage rate is taken from Table 8B in Annex 8 of the *2012 Guidelines to Defra/DECC's GHG Conversion Factors for Company Reporting*. To determine which leakage rate applies the units were compared with the sizing guide in the December 2011 ICF document *Development of the GHG Refrigeration and Air Conditioning Model Final Report*. All units were judged to be "Small Stationary Air Conditioning" units.

The time used by each unit was calculated as 24% of time available in the year based on an assumed usage of 8 hours per day, 5 days per week = 40 hours per week/168 hours in week= 24%.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Refrigerant & other	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Emission	Unit	kg CO_2e
Montreal protocol - standard	HCFC-22/R22 = chlorodifluoromethane	kg	1810

Activity	Emission	Unit	kg CO_2e
Kyoto protocol- blends	R407A	kg	2107
	R410A	kg	2088

The capacity for each HFC type is multiplied by the time used percentage, the annual leak rate and the global warming potential conversion factor to provide the tCO_2e number.

For 2016/17 the calculation is as follows:

- R22: 0.0384 tonnes charging capacity x 24% usage x 3% leakage rate x 1,810 = 0.50 tCO2e.
- R407C: 0.1708 tonnes charging capacity x 24% usage x 3% leakage x 1,774 = 2.18 tCO2e.
- R410A: 0.93837 tonnes charging capacity x 24% usage x 3% leakage x 2,088 = 14.10 tCO2e.

This gives a total of 16.78 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 2.0308613 (cell AZ41) was used:

- Total emissions 2016/17 = 8.262504 kg (cell BP41) x 2.0308613= 16.78 (cell AE41).

DNO Emissions: Fuel Combustion – Diesel

The fuel combustion - diesel figure is calculated from fuel litres purchased data provided by the business plant card supplier.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Fuels	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Diesel (average bio fuel blend)	litres	2.61163

For 2016/17 the calculation is as follows:

Consumption: 66 337.00 litres x 2.61163 / 1 000 = 173.25 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.0026117 (cell AZ47) was used:

- Total consumption 2016/17 = 66 337.00 litres (cell BP47) x 0.0026117 = 173.25 (cell AE47).

DNO Emissions: Fuel Combustion – Other

The fuels other figure is calculated from fuel litres purchased data provided by the business fuel and fuel card suppliers.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Fuels	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Fuel	Unit	kg CO_2e
Gaseous fuels	LPG	litres	1.50502

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.96572
	Petrol (average bio fuel blend)	litres	2.19697

For 2016/17 the calculation is as follows:

- Petrol consumption: 21 516.00 litres (average bio fuel petrol) x 2.19697 / 1 000 = 47.27 tCO2e.
- Gas oil consumption: 113 400.00 litres x 2.96572 / 1 000 = 336.31 tCO2e

This gives a total of 383.58 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 0.0033825 (cell AZ49) was used:

- Total consumption 2016/17 = 113 400.00 litres (cell BP49) x 0.0033825 = 383.58 (cell AE49).

DNO Emissions: Losses

Losses occur in all electricity networks, and for GB distribution companies typically represent 5-10% of energy distributed to end customers. Losses are usually divided into two categories: technical and non-technical. Technical losses can be further divided into fixed losses (e.g. transformer iron losses) and variable losses which are dependent on power flows in circuits, both of which have a direct carbon impact. Non-technical losses include unregistered or illegal connections, theft, meter inaccuracies, meter settlement errors and other settlement data issues.

Losses are measured as the difference between energy entering (generation) and energy exiting the network (demand), as recorded under the Balancing and Settlement Code (BSC) arrangements. Reported losses therefore do not distinguish between technical and non-technical losses.

The reported figure is a snapshot of received data as of the date of this report and will change as further settlement reconciliation runs are carried out (up to 28 months after each relevant settlement date).

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	UK electricity	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 2	**Version:**	1.0	**Year:**	2016

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2016	0.41205

For 2016/17 the calculation is as follows:

- Reported losses = 1 408 449 595.67 kWh x 0.41205 / 1000 = 580 351.66 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.00041205 (cell AZ55) was used:

- Total consumption 2016/17 = 1 408 449 595.67 kWh (cell BP55) x 0.00041205 = 580 351.66 (cell AE55).

Contractors
When reporting BCF emissions due to contractors in the second half of the worksheet please:

- Explain, and justify, the exclusion of any contractors and any thresholds used for exclusion.
- Provide an indication of what proportion of contractors have been excluded. This figure could be calculated based on contract value.

Please provide a description of contractors' certified schemes for BCF where a breakdown of the calculation for their submitted values is not provided in the worksheet.

If a DNO's accredited contractor is unable to provide a breakdown of the calculation and has entered a dummy volume unit of '1' in the worksheet please provide details of the applicable accredited certification scheme which applies to the reported values.

For the BCF emissions due to contractors, only Operational Transport – Road and fuels other have been calculated.

The fuel usage figure from contractors includes the usage by the larger framework contractors only and excludes any usage by smaller, low volume sub-contractors where the collation of data is impractical. The proportion of BCF emissions attributable to the excluded contractors is estimated at less than 10%.

Contractor Emissions: Operational Transport – Road

The contractor operational transport figure is calculated using road fuel litres used data provided by contractors in relation to their fleet usage on our behalf.

The fuel usage figure from contractors includes the usage by the larger framework contractors only and excludes any usage by smaller, low volume sub-contractors where the collation of data is impractical.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Fuels	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Diesel (average bio fuel blend)	litres	2.61163

For 2016/17 the calculation is as follows:

Consumption = 1 382 225.67 litres x 2.6116262 / 1 000 = 3 609.86 tCO2e.

To ensure this figure was the 2017 entry in table E3 a scalar of 0.0026116262 (cell AZ68) was used:

- Total consumption 2016/17 = 1 382 225.67 litres (cell BP68) x = 0.0026116262 = 3 609.86 (cell AE68).

Contractor Emissions: Fuel Combustion – Other

The fuels other figure is calculated from fuel litres used data provided by contractors in relation to their generator and plant usage on our behalf.

To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	Fuels	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 1	**Version:**	1.0	**Year:**	2016

Activity	Fuel	Unit	kg CO_2e
Gaseous fuels	LPG	litres	1.50502

Activity	Fuel	Unit	kg CO_2e
Liquid fuels	Gas oil	litres	2.96572
	Petrol (average bio fuel blend)	litres	2.19697

For 2016/17 the calculation is as follows:

- Petrol consumption = 5 688.46 litres (average bio fuel petrol) x 2.19697 / 1 000 = 12.50 tCO2e.
- Gas oil consumption: 703 473.90 litres x 2.96572 / 1 000 = 2 086.31 tCO2e
- LPG consumption = 1 116.00 litres x 1.50502 / 1 000 = 1.68 tCO2e.

This gives a total of 2 100.49 tCO2e. To ensure this figure was the 2017 entry in table E3 a scalar of 0.0029572772 (cell AZ95) was used:

- Total consumption 2016/17 = 710 278.36 litres (cell BP95) x 0.0029572772 = 2 100.49 (cell AE95).

Building energy usage
Natural gas, Diesel and other fuels are all categorised as fuel combustion and must be converted to tCO2e on either a Gross Calorific Value (Gross CV) or Net Calorific Value (Net CV) basis. The chosen approach should be explained, including whether it has been adapted over time.

Substation Electricity must be captured under Buildings Energy Usage. Please explain the basis on which energy supplied has been assessed.

We only use electricity as our energy source for buildings and substations.

The buildings and substation electricity energy usage figures are calculated using kWh usage data. To convert the usage into tCO_2e the following conversion factors from the *UK Government Conversion Factors for Company Reporting 2016 Version 1.0* were used:

Emissions source:	UK electricity	**Expiry:**	31/06/2017	**Factor set:**	Full set
Scope:	Scope 2	**Version:**	1.0	**Year:**	2016

Activity	Country	Unit	Year	kg CO_2e
Electricity generated	Electricity: UK	kWh	2016	0.41205

E4 – Losses Snapshot

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

The Losses Snapshot Table E4 has been completed based on the losses reduction initiatives detailed in our current Losses Strategy (April 2015). Other work may have helped to reduce Distribution Losses but the decision to undertake the activity was not driven by losses benefit, therefore this activity is not reported in Table E4.

ENWL, for the 2016 RRP submission, updated the RIIO-ED1 CBA in respect of 'Fixed data' (WACC, GHG conversion factor, Traded carbon price & Value of Losses) and in respect of costs (referred to 2012-13 prices). Ofgem has advised, for the 2017 RRP submission, that the CBA assumptions used in the RIIO-ED1 submissions shall be used. This maintains consistency with business decisions outlined in the Well Justified Business Plan.

The ENWL WJBP Losses Strategy was significantly improved in the first year of RIIO-ED1 resulting in our 2015 Losses Strategy. The 2015 Losses Strategy used the RIIO-ED1 CBA as the basis for its decision making; with 'Fixed data' assumptions unchanged from the WJBP but costs updated based on better procurement information.

This RRP (2017) submission is based on the same assumptions as the 2015 Losses Strategy.

Technical Losses

All costs reported in Table E4 (Columns V and AD) and those costs contained within the supporting CBA workbooks are reported in 2012-13 price base to be consistent with our Losses Strategy (April 2015).

The Technical Losses reduction initiatives from the (2015) Losses Strategy are summarised below:

- Opportunistic installation with 300mm^2 HV cable
- Opportunistic installation with 300mm^2 LV cable
- Proactive replacement of 1000kVA ground mounted transformers
- Proactive replacement of 800kVA ground mounted transformers
- Opportunistic installation of primary transformers (33kV/HV)
- Opportunistic replacement of pre-1970 200kVA pole mounted transformers

The following provides the detail of any estimates, allocations or apportionments made when calculating the numbers submitted for each of the initiatives;

All Technical Losses Initiatives

Where the primary driver (column E) is detailed as General Reinforcement the base volume number is taken from C&V Tables CV1 and CV2

Where the primary driver (column E) is detailed as Fault Level Reinforcement the base volume number is taken from C&V Table CV3

Where the primary driver (column E) is detailed as Asset Replacement the base volume number is taken from C&V Table CV7

Where the primary driver (column E) is detailed as Other the base volume number is taken from C&V Tables CV5, CV6, CV13, CV14, CV15, CV16, CV18, CV19, CV20, CV22, CV23, CV24, CV25, CV26, CV27, CV28, CV29, CV36, CV38, CV39, V3 and V4.

For all initiatives it was assumed that there were no losses saving in the first year (2015-16) and the full losses saving in the following years.

Opportunistic installation with 300mm2 HV cable

We purchase HV cable in the following standard sizes; 95mm^2, 185mm^2 and 300mm^2. Our corporate Capital Programme Management system (CPM) does not record the size of cable installed. Therefore, the volumes of 300mm^2 HV cable (km) installed is calculated to be the aggregate volume from the appropriate CV Table (per driver) apportioned in the ratio of 300mm^2 HV cable purchased: total HV cable purchased.
The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The unit (1km) losses benefit was calculated as the losses saved by replacing a 185mm^2 HV cable with 300mm^2 HV cable. The peak current was assumed to be the thermal rating of the 185mm^2 cable. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Opportunistic installation with 300mm2 LV cable

We purchase LV cable in the following standard sizes; $95mm^2$, $185mm^2$ and $300mm^2$. Our corporate Capital Programme Management system (CPM) does not record the size of cable installed. Therefore, the volumes of $300mm^2$ LV cable (km) installed is calculated to be the aggregate volume from the appropriate CV Table (per driver) apportioned in the ratio of $300mm^2$ LV cable purchased: total LV cable purchased.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The unit (1km) losses benefit was calculated as the losses saved by replacing a $185mm^2$ LV cable with $300mm^2$ LV cable. The peak current was assumed to be the thermal rating of the $185mm^2$ cable. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Proactive replacement of 1000kVA & 800kVA ground mounted transformers

The volume of 1000kVA and 800kVA ground mounted transformers replaced proactively (Equipment to manage losses) is reported in CV21. The volume split between the 1000kVA and the 800kVA units is established by inspection of our Master Asset Management System (MAMS).

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The losses calculations are based on transformer resistance values. The peak current was assumed to be the thermal rating of the of the transformer type. A typical (for ENWL) load factor of 0.6 was assumed for urban areas of the network leading to a calculated loss load factor of approximately 0.38.

Opportunistic installation of primary transformers (33kV/HV)

Eleven primary transformers were delivered in 2016-17.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The losses calculations are based on transformer resistance values. The peak current was assumed to be half (because primary transformers are installed as pairs for resilience) the thermal rating of the of the transformer type. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Opportunistic replacement of pre-1970 200kVA pole mounted transformers

We purchase pole mounted HV/LV transformers in the following standard sizes;

- 25kVA – single phase
- 50kVA – single phase
- 100kVA – single phase

- 25kVA – three phase
- 50kVA – three phase
- 100kVA – three phase
- 200kVA – three phase

Our corporate Capital Programme Management system (CPM) does not record the size of transformer installed. Therefore, the volumes of 200kVA transformers installed is calculated to be the aggregate volume from the appropriate CV Table (per driver) apportioned in the ratio of 200kVA transformers released from store: total pole mounted transformers released from store.

The baseline solution and losses reduction activity unit costs are the same as those assumed for our 2015 Losses Strategy and are expressed on 2012-13 prices.

The losses calculations are based on transformer resistance values. The peak current was assumed to be the thermal rating of the of the transformer type. A typical (for ENWL) load factor of 0.53 was assumed across the network leading to a calculated loss load factor of approximately 0.3.

Non-Technical Losses

The costs associated with Relevant Theft of Electricity activities are taken directly from table I5. These costs included the costs of investigating all reported or suspected instances of Relevant Theft of Electricity. Many of these are not ultimately found to be cases of Relevant Theft of Electricity, and therefore have no losses benefit associated with them, but costs are included to reflect the full cost of operating a Relevant Theft of Electricity activity.

The income associated with Relevant Theft of Electricity activities is also taken directly from table I5. This income represents all income received during 2016-17 and will include some payments received from instances of theft identified in prior years (for example where a customer agrees to a payment plan and pays the debt over several years). We make no adjustment in our CBA to reflect the lag in receiving income.

The net of costs and associated income is reported within the losses snapshot table. As income was slightly higher than costs during 2016-17 we report a negative value for this year.

We estimate the losses benefit associated with identifying and remedying instances of Relevant Theft of Electricity as follows:

- For sites where we have billed the customer for the value of electricity for 12 months of theft (our usual approach), we quantify losses based on the invoiced amount of electricity used. We assume that this full losses benefit is achieved in the year that we identify the theft, reflecting the fact that the full 12 months has been invoiced. We assume this whether or not the customer has yet paid anything against the invoice; this reflects the benefit associated with there being no ongoing theft.

- For sites where we have billed the customer for the value of electricity for less than 12 months of theft (for example if the customer has not lived in the property for a year), we quantify losses benefit in year 1 based on the invoiced amount of electricity used. For subsequent years we increase the losses benefit to a full 12 month effect – reflecting the full amount of electricity that will no longer be being stolen. We assume this whether or not the customer has yet paid anything against the invoice; this reflects the benefit associated with there being no ongoing theft.

- For sites where we have identified theft but have not raised an invoice, for example where we have no reasonable expectation of recovering the costs, where the values involved are very small (for example where a customer has only just moved into a property) or where all lost units will be recovered via a supplier (following registration of a new MPAN) we assume a losses benefit of 10kWh per day for domestic properties and 30kWh a day for commercial properties. We assume that none of this losses benefit is achieved in the year that we identify the theft, with 100% of the benefit achieved from year 2 onwards.

These losses benefits reflect the fact that electricity is no longer being stolen – either the theft has ceased or the units are being entered into settlements.

In all cases we assume that the losses benefits persist on an ongoing basis i.e. that the customer continues to use electricity at the rate we assumed, that the customer does not revert to stealing electricity and that the site is not disconnected.

Volume of Lost Units Recovered from End Customers

For each case an estimate of the lost units recoverable is prepared based on:

- Actual meter readings or

- Electrical load readings and

- Period of responsibility of the current customer

This is usually capped with a maximum of 12 months for Domestic and Micro Businesses (using up to 100,000kWh pa)

Extra Lost Units associated with each billed case

Not all customers are responsible for the full 12 months. Previous customers may also have unbilled units.

Each case is assessed to determine how many months had been recovered. Any additional month’s usage is assessed pro rata.

Lost units associated with unbilled cases

Many cases come to light when new customer move in and make enquiries about their MPANs and who their supplier is. These customers are not responsible for previous usage but the premises have been occupied so there will be unrecovered losses associated with these investigations. Each case is assessed for responsibility for losses. The number of Domestic and Commercial cases is determined and Typical Annual Usage Rates applied.

Typical Annual Usage rates

10 units/day domestic, 30 units/day Commercial

Programme/Project Title
Please provide a brief summary and rationale for each of the activities in column C which you have reported against.

Technical Losses

Opportunistic installation with 300mm2 HV cable

Opportunistic installation of large cross-section cables (300mm^2) at high voltage (HV – 6.6kV and 11kV) as standard, instead of a mix of smaller (95mm2 and 185mm2) cables. This will reduce circuit resistance, reduce losses and provides a positive business case.

Opportunistic installation with 300mm2 LV cable

Opportunistic installation of large cross-section cables (300mm^2) at low voltage (LV – 430/240V) as standard, instead of a mix of smaller (95mm2 and 185mm2) cables. This will reduce circuit resistance, reduce losses and provides a positive business case.

Proactive replacement of 1000kVA ground mounted transformers

Proactively replace old (pre-1990) 1000kVA, ground mounted, secondary network transformers with lower loss EU Eco Design 2015 specification transformers. The old transformers have particularly high losses such that there is a positive business case for proactive replacement of these units.

Proactive replacement of 800kVA ground mounted transformers

Proactively replace old (pre-1990) 800kVA, ground mounted, secondary network transformers with lower loss EU Eco Design 2015 specification transformers. The old transformers have particularly high losses such that there is a positive business case for proactive replacement of these units.

Opportunistic installation of primary transformers (33kV/HV)

When installing or replacing a primary transformer, a lower loss unit which complies with the latest European Union standard (EU Eco Design 2015) specification will be installed. The lower loss units can now be procured at the same cost as the old (higher losses) specification units; therefore there is a positive business case for opportunistic replacement of these units.

Opportunistic replacement of pre-1970 200kVA pole mounted transformers

When installing or replacing a 200kVA pole mounted transformer, a lower loss unit which complies with the latest European Union standard (EU Eco Design 2015) specification will be installed. The losses reduction provides a positive business case that justifies the marginal unit cost increase.

Non-Technical Losses

Proactive investigation of Relevant Theft of Electricity. Identifying of instances of theft, rectifying the theft so that electricity is no longer stolen and, where appropriate, seeking to recover the value of electricity stolen and any associated costs from the customer. During 2015-16 we identified many instances of Relevant Theft of Electricity, delivering significant losses benefits by preventing further theft or ensuring units are correctly captured in settlements. We recovered associated monies from customers that totalled slightly more than our associated costs.

Primary driver of activity
If, in column E, you have selected 'Other' as the primary driver of the activity, please provide further explanation.

In respect of Technical Losses initiatives 'Other' has been selected as a primary driver (in column E) where the initiative is an opportunistic investment. Opportunistic initiatives are changes in policy affecting all business as usual activities. So for example installing larger cross-section HV cable as standard will affect reinforcement, asset replacement, fault level and any other activity that requires HV cable.

In respect of Relevant Theft of Electricity activity 'Other' has been selected as a primary driver (in column E) because it does not apply to reinforcement, asset replacement and fault level activities.

Baseline Scenario
Please provide a brief description of the 'Baseline Scenario' inputted in column K for each activity.

Technical Losses

Opportunistic installation with 300mm2 HV cable

The baseline scenario is to continue to install 95mm^2 and 185mm^2 cables. In the CBA analysis the baseline scenario assumed activity was all 185mm^2 cable producing a conservative estimate of losses reduced.

Opportunistic installation with 300mm2 LV cable

The baseline scenario is to continue to install $95mm^2$ and $185mm^2$ cables. In the CBA analysis the baseline scenario assumed activity was all $185mm^2$ cable producing a conservative estimate of losses reduced.

Proactive replacement of 1000kVA ground mounted transformers

The baseline scenario assumed that the high loss 1000kVA transformer units were not replaced.

Proactive replacement of 800kVA ground mounted transformers

The baseline scenario assumed that the high loss 800kVA transformer units were not replaced.

Opportunistic installation of primary transformers (33kV/HV)

The baseline scenario assumed that primary transformers that complied with ENWL's old standard would be installed.

Opportunistic installation of pre-1970 200kVA pole mounted transformers

The baseline scenario assumed that 200kVA pole mounted transformers that complied with ENWL's old standard would be installed.

Non-Technical Losses

The baseline scenario assumes that no Relevant Theft of Electricity activity is undertaken.

We set the baseline losses assumption to be equal to the benefits associated with theft identified during the year. In reality it is likely that the losses associated with ongoing theft is greater than this – but it is impossible for us to quantify this. As CBA modelling works on a marginal basis this approach should appropriately reflect the benefits gained.

Use of the RIIO-ED1 CBA Tool

DNOs should use the latest version of the RIIO-ED1 CBA Tool for each of the activities reported in column C. Where the RIIO-ED1 CBA Tool cannot be used to justify an activity, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report must be submitted.

RIIO-ED1 CBA Tool version 'Template CBA RIIO ED1 v4' has been used or all CBA analysis associated with this submission.

We have not changed the assumptions from those contained within 'Template CBA RIIO ED1 v4'.

Changes to CBAs

If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows:

- a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, or
- a substantively different NPV from that used to justify an activity that has already begun.

the DNO should include an explanation of what has changed and why the DNO is continuing the activity.

For example, where the carbon price used in the RIIO-ED1 CBA Tool has changed from that used to inform the decision such that the activity no longer has a positive NPV.

N/A.

Cost benefit analysis additional information

Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each activity reported in column C in the Regulatory Year under report.

The table below lists the Losses initiative and the name of its relevant CBA:

Losses Initiative	Primary Driver of Activity	CBA Name
Opportunistic installation with 300mm^2 HV cable	General Reinforcement	2017 Install 300sqmm HV Cable versus 185sqmm HV CV1 CV2
Opportunistic installation with 300mm^2 HV cable	Fault Level Reinforcement	2017 Install 300sqmm HV Cable versus 185sqmm HV CV3
Opportunistic installation with 300mm^2 HV cable	Asset Replacement	2017 Install 300sqmm HV Cable versus 185sqmm HV CV7
Opportunistic installation with 300mm^2 HV cable	Other	2017 Install 300sqmm HV Cable versus 185sqmm HV Other
Opportunistic installation with 300mm^2 LV cable	General Reinforcement	2017 Install 300sqmm LV Cable versus 185sqmm LV CV1 CV2
Opportunistic installation with 300mm^2 LV cable	Asset Replacement	2017 Install 300sqmm LV Cable versus 185sqmm LV CV7
Opportunistic installation with 300mm^2 LV cable	Fault Level Reinforcement	2017 Install 300sqmm LV Cable versus 185sqmm LV CV3
Opportunistic installation with 300mm^2 LV cable	Other	2017 Install 300sqmm LV Cable versus 185sqmm LV Other
Proactive replacement of 1000kVA ground mounted transformers	Equipment to manage losses	2017 Proactive 1000kVA GMT Replacement CV21
Proactive replacement of 800kVA ground mounted transformers	Equipment to manage losses	2017 Proactive 800kVA GMT Replacement CV21
Opportunistic installation of primary transformers (33kV/HV)	Asset Replacement	2017 Opportunistic 200kVA PMT Replacement CV7
Opportunistic replacement of pre-1970 200kVA pole mounted transformers	Other	2017 Opportunistic 200kVA PMT Replacement Other
Opportunistic replacement of pre-1970 200kVA pole mounted transformers	Asset Replacement	2017 Programme 23MVA Replacement CV7
Opportunistic replacement of pre-1970 200kVA pole mounted transformers	Other	2017 Programme 23MVA Replacement Other
Relevant Theft of Electricity	Other	Relevant theft v no activity CV21 CBA vfinal

E5 – Smart Metering

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
N/A.

Actions to deliver benefits

Detail what activities have been undertaken in the relevant regulatory year to produce benefits of smart metering where efficient and maximise benefits overall to consumers. At a minimum this should include:

- A description of what the expenditure reported under Smart Meter Information Technology Costs is being used to procure and how it expects this to deliver benefits for consumers.
- A description of the benefits expected from the non-elective data procured as part of the Smart Meter Communication Licensee Costs. The DNO should set out how it has used this data.
- A description of the Elective Communication Services being procured, how it has used these services, and a description of the benefits the DNO expects to achieve.

The £1.45m Communication Licensee Costs are those costs payable by us to the Data and Communications Company (DCC), as required by the Smart Energy Code and defined by DCC's published charging methodology statement. DCC's systems and our gateway have been delayed. The DCC system is due to go live in July 2017 with our gateway following within six months.

The £2.94m IT costs incurred in 2016-17 covered the procurement, implementation and commissioning of the gateway infrastructure connecting our IT systems to the Data and Communications Company's (DCC) central systems as part of the Smart Meter Implementation Programme and required by the Smart Energy Code. Connection to DCC's central systems facilitates access to smart meter data, generated from alerts and service requests, which in the longer term will enable a network operator to manage its network more effectively and cost efficiently for its customers.

DCC costs have risen significantly from 2015-16 and are forecast to continue to rise through to 2020.

Calculation of benefits

Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.

N/A. The Smart Meter programme has not yet rolled out to the extent that benefits are identifiable.

Use of the RIIO-ED1 CBA Tool DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the worksheet in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report which is used to complete the worksheet must be submitted.
N/A.

Cost benefit analysis additional information Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.
N/A.

E6 – Innovative Solutions

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

Capacity to Customers

The actual costs were the total of the connection cost for an n-0 solution paid by the customer for schemes connected at EHV. The benefits were calculated by assuming EHV reinforcement of £300 per metre for cable and £200k for a primary switchboard change. It was also assumed that the customer would pay 100% of the additional costs as the increased security is wholly for their benefit.

Transformer Regeneration

This solution was based on the baseline scenario of replacing or refurbishing all Grid and 33kV transformers which had a HI of 5 and refurbishing those with a HI of 4. The regeneration solution is to replace transformers at HI5 with a criticality of 2-4 and refurbish those at HI5 (criticality 1) and HI4 (criticality 2-4). The costs used in the CBA are derived from the CV7 and CV9 tables from the Costs and Volumes pack.

Fault Support Centre

The CBA was based on the number of LV ways fitted with reclosing devices during 2016-17 and the number of times the devices operated prior to the fault being located and repaired. It was assumed faults occurred linearly throughout the week and therefore costs for the baseline case include premium time working. Each callout to replace a fuse was costed at three hours and it was assumed that customers would be without supply for at least 90 minutes.

Repairs were assumed to commence immediately a fault became permanent. It was assumed that the installation of reclosing devices removed the requirement for fuse replacement and as supplies were restored within three minutes, the Customer Interruptions and Customer Minutes Lost were reduced. The input from the Fault Support Centre allowed faults to be located prior to becoming permanent and it was assumed that all faults were repaired during normal working hours. The cost of setting up the FSC was included in year 1 of the CBA.

Connect and Manage PV Clusters

The volumes used for this CBA were based on the numbers of customers added to the Feed-In Tariff database during 2016-17. For the baseline scenario, it was assumed that there would be a requirement to purchase a tool for LV system analysis and that clusters of pV would consist of 24 properties covering 5% of the total. The remaining 95% would have an average 1.5 properties per application. Planning time was allocated at 12 hours per scheme for larger schemes and one hour per scheme for smaller schemes.

Solutions for the larger schemes were split between LV cable overlay (5%), transformer change (5%) and altering transformer taps (40%). It was assumed that for 50% of the larger schemes and all of the smaller schemes that the PV demand was approved.

For the Connect & Manage scenario, it was assumed that 2% of the applications would lead to LV system monitoring being installed resulting in 2% of the total number requiring further planning of which 25% required a cable overlay, 10% required a transformer change and 65% required the tap position altering.

In the CBA calculations the Feed-In Tariff number was provided by Ofgem. This number (947) differs from the PV installed number in table E7 (1058) which is the number of installations that we had been informed of.

Demand Side Response (Catterall)

Catterall primary is compliant with ENA Engineering Recommendation (ER) P2/6. The non-compliance issue only exists when the system is operating abnormally (i.e. under a fault situation), as the demand exceeds the transfer firm capacity. Deferring the reinforcement and entering into a commercial contract with United Utilities to purchase the demand at Catterall allows us to monitor Catterall's primary demand patterns and enables us to be compliant with ER P2/6.

Catterall Primary Substation has a single 7.5MVA transformer and a firm capacity of 5 MVA, limited by High Voltage transfer capability. The peak demand at Catterall Primary is 7.41 MVA, which exceeds the firm capacity by 2.41 MVA.

The CBA uses the agreed commercial costs of £13,500 per MVA, in which we purchase 3 MVA under such fault conditions. The CBA was informed by actual costs as referenced in table C1 and the losses were calculated based on load projections up to 2061.

Power Saver Challenge

In May 2013, we commissioned National Energy Action (NEA) and Sustainability First to evaluate the potential for electrical load reduction measures to be implemented in an area of Stockport served by the Vernon Park Grid Supply Point to mitigate the need for network reinforcement.

The objective of this project was to prove the concept of deploying proactive demand reduction at a domestic consumer level to efficiently address network capacity issues whilst delivering additional social benefits. Consumers were encouraged to significantly reduce winter peak time load and if successful, in return would receive a reward at the end of the trial period.

The Phase 2 trial lasted for 18 months to enable the recruitment of sufficient participating consumers and deliver rewards from the incentive mechanism. There was then a 12 month period whereby the monitoring equipment was left commissioned to record consumer's behaviour. This allowed us to assess the long term effects of the project and ensure they are embedded with regard to consumer's behaviour change.

General

For each of the solutions please explain:

- In detail what the solution is, linking to external documents where necessary.
- How this is being used, and how it is delivering benefits.
- What the volume unit is and what you have counted as a single unit.
- How each of the impacts has been calculated, including what assumptions have been relied upon.

Introduction

For the second year of the RIIO-ED1 period, we have continued to both prepare for and actually deploy a number of Innovative Solutions. Many of these solutions will come into active use in future years and our activities have been limited to transitioning them into BAU via a number of new and amended policy updates, completion of associated procurement exercises to allow us to purchase key products and services as well as internal training on how to carry out the range of activities associated with the deployment of the innovative solutions.

This commentary and associated CBAs contain details of the innovative solutions which have incurred expenditure and delivered outputs/units in 2016-17 and where this expenditure was undertaken as part of normal business (i.e. not innovation funded projects).

The table below contains a complete list of all of the innovative solution that were deployed in 2016-17 and which can be traced back to IFI, LCNF Tier 1 or LCNF Tier 2 projects. However, while several of these are presented as separate projects they are eventually brought together in combination to form a new and innovative solution. The table below summarises these interactions. Owing to this combination of several projects into combined solutions and to avoid double counting of the associated costs and benefits, a CBA has only been prepared for the combined solution.

Innovative Solutions

There are six Innovative Solutions which formed part of our business as usual activities during 2016-17. These are listed below together with the project on which the Innovative Solution depends. These projects are shown in brackets alongside the innovative solutions.

- Capacity to Customers
- Demand Side Response – Catterall
- Power Saver Challenge
- Transformer Regeneration (Combined Online Transformer Monitoring)
- Fault Support Centre (Bidoyng Smart Fuse)
- Connect and Manage of PV Clusters (LV Smart Joint)

Capacity to Customers (now known as managed connections)

<u>What the solution is</u>

Managed connections provide customers wishing to connect to the network with a lower cost connection and reduced waiting times versus traditional network reinforcement-based connection arrangements. It utilises advances in network automation and communications alongside innovative commercial terms. It is a form of Active Network Management (ANM) solution which may seek to disconnect managed customers from the network for agreed periods only in the event of a relevant network fault.

<u>How the solution is being used</u>

Managed connections are now the standard connection offer provided to all generation customers connecting to the HV and EHV network. Managed connections afford customers a lower cost connection and as such have become the default connection offer provided to all DG customers.

To support decision making by customers, information on the potential 'curtailment factor' (i.e. the typical period of time that a customer could expect to be at risk of disconnection) is provided alongside the connection offer. Customers may choose to reject the managed connection offer and instead opt for a more traditional connection arrangement without the managed elements.

<u>How the solution is delivering benefits</u>

Managed connections are providing a number of benefits. Economic benefits flow to connection customers from lower reinforcement costs and reduced time to connect. Environmental benefits accrue as a result of the connection of low carbon generation such as solar/wind farms.

Demand Side Response – Catterall

<u>What the solution is</u>

Catterall Primary Substation has a single 7.5MVA transformer and a firm capacity of 5 MVA, limited by High Voltage transfer capability. The peak demand at Catterall Primary is 7.41 MVA, which exceeds the firm capacity by 2.41 MVA.

Catterall primary is compliant with ENA Engineering Recommendation (ER) P2/6. The non-compliance issue only exists when the system is operating abnormally (i.e. under a fault situation), as the demand exceeds the transfer firm capacity. Deferring the reinforcement and entering into a commercial contract with United Utilities to purchase the demand at Catterall allows us to monitor Catterall's primary demand patterns and enables us to be compliant with ER P2/6. Purchasing Demand Response (DR) ensures that the demand does not exceed the capacity when the system is abnormal.

How the solution is being used

Under system abnormal conditions, we will switch out the United Utilities circuit at Catterall GSP to reduce the demand at the United Utilities Franklaw site, to the enable the restoration of supplies connected to Catterall GSP so the transfer capacity of 5 MVA is not exceeded. United Utilities have agreed to have their demand reduced by 3 MVA for up to eight hours to allow time for us to identify and resolve the issue. This is an agreed three year contract, with a payment of £13,500 per MVA, for six events over the three year period.

How the solution is delivering benefits

DR provides a lower value of excess capacity and with continuous monitoring provides the opportunity to analyse the demand to defer or carry out reinforcement in the future if demand increases.

Power Saver Challenge

What the solution is

The project covered 1,055 domestic consumers within the Stockport area of Greater Manchester. Half of these consumers are located in the Heaton Mersey area which is generally affluent, the other half are located in the Heaton Norris area that has a high proportion of fuel poverty residents. Electricity demand monitoring was installed on the feeder at the local substation supplemented by in-home monitoring devices to measure the impact of the demand reduction measures and any changes in consumer behaviour. A target of up to 1MW of peak load reduction was set. This project forms part of our Corporate and Social Responsibility plan.

How the solution is being used

The recommended interventions of reduced energy usage from washing machines, cooking appliances and power showers were supplemented with the improved lighting efficiency options. These technically enabled options were packaged together as a suite of efficiency measures and provided free of charge to participating consumers. Participating consumers agreed to the fitting of low energy light bulbs, washing machine controllers and shower timers funded by the project. The installations were accompanied by an education programme for the households.

How the solution is delivering benefits

Project costs were reported as General Reinforcement. A target of up to 1MW of peak load reduction was set. However, in this particular example it was decided to reinforce the network in the area and as such, this project acts as a proof of concept rather than a specific alternative to network reinforcement.

Transformer Regeneration

Another significant innovation which we have now transitioned across to BAU is the regeneration of transformers to avoid the need to replace with new. During the FY16 period our activities were limited to the preparation and mobilisation of the various teams that will be used to delivery this programme. Several Refurbishment works were carried out in FY17. However for some further sites there are additional works which are at an advanced stage of completion and these will be reflected in the volumes for 2017-18. We have included the details of this innovation within this commentary but the volumes for those works in the final stages of completion have been omitted from table E6.

What the solution is

The condition of the oil in the transformer main tank is a good proxy for the general condition of the transformer as a whole. It has been shown from recent research that deployment of a unique application of transformer oil regeneration (a process whereby transformer oil is cleaned through an on-site process) can result in an improvement in overall condition of the transformer which when used in combination with enhanced condition monitoring, can extend the expected life of the transformer.

How the solution is being used

Transformer regeneration is being used as an alternative to traditional transformer replacement during RIIO-ED1 thus reducing the cost of asset replacement.

How the solution is delivering benefits

The financial benefits from this project are derived from the potential transformer life extension and deferment of asset replacement costs. Other benefits include quality of supply benefits which are limited to improved understanding of the risk of failure of older transformers and a better insight into the oil ageing process. The Environmental benefits result from extending the life of transformer and its oil therefore reducing the requirement for disposal and recycling of used oil and scrap transformers.

Combined online transformer monitoring (facilitates Transformer Regeneration)

What the solution is

As transformer life is extended through the use of techniques such as transformer oil regeneration, network operators must be certain that the life extended units will continue to operate both safely and reliably. To support this, a real-time condition monitoring system has been developed which provides us with enhanced information on each refurbished transformer via an on-line information dashboard.

How the solution is being used

Transformer monitoring will be fitted to all transformers which are to have their oil regenerated in RIIO-ED1 for a period of time to confirm via observable data that both the initial condition of the transformer is improved and that this improved condition is maintained thereafter. The solution is being used as part of our intervention plan to extend the life of a large number of Grid & Primary transformers. The technology is fitted to targeted transformers for a short period prior to the commencement of the regeneration process and continues for a defined period thereafter.

How the solution is delivering benefits

The condition monitoring provides us with confirmation that the transformer regeneration process has been successful in improving the condition of the transformer oil and thus the main tank. The combined online transformer monitoring is a key enabling technology for the refurbishment of large volumes of Grid & Primary transformers via the Transformer Regeneration Innovative Solution.

Fault Support Centre (FSC)

What the solution is

The Fault Support Centre is an enhanced Low Voltage network fault management solution which makes use of the increased penetration of intelligent devices such as the Bidoyng coupled with innovative commercial partnership with a third party provider. The FSC provides a real-time operational management of low voltage networks to allow for the proactive management of faults. The data obtained can be further used to target areas of the network which would benefit from asset replacement.

How the solution is being used

The solution is being used as the business-as-usual way in which all transient faults are managed. In the event that a transient fault is detected, a Bidoyng smart fuse (or suitable alternative such as the Weezap) is fitted to the suspect LV network. Our third party service provider (Kelvatek) is informed of the event and crucial information is passed across that allows real-time monitoring of the associated network.

Kelvatek will continue to monitor the affected networks until they have determined the location of the fault and issued an instruction to our field teams to investigate or it can be reasonably shown that the transient fault is no longer active. In such cases, the equipment will be recovered and redeployed elsewhere.

How the solution is delivering benefits

The Fault Support Centre allows for the proactive management of LV transient faults. It is clear from our own customer engagement that these types of fault are amongst the biggest cause of customer dissatisfaction. The ability to repair these faults before they have chance to progress into a permanent fault will significantly reduce the number of associated faults and reduce customer disruption accordingly.

Further benefits flow from the reduced CI and CML and associated fault costs that the proactive management of faults delivers.

Bidoyng (smart fuse) (facilitates Fault Support Centre)

What the solution is

The Bidoyng is an innovative replacement for the standard low voltage fuse. It provides for a multi-shot re-close feature as opposed to the single shot available from the standard fuse. This means that customer supplies can be automatically restored in the event of a transient fault. This reduces the number of customer interruptions and customer minutes lost, reduces the cost associated with managing our response to a loss of supply and LV fault and improves customer satisfaction outcomes.

In addition, the Bidoyng provides increased network visibility via its ability to measure and transmit via SCADA key network parameters and make this available in near real-time.

How the solution is being used

The Bidoyng is used to reduce the customer impacts of faults, support increased understanding of the impact of the connection of low carbon technologies and improve the management of network faults.

The Bidoyng smart fuse is acting as an enabler for a number of innovation solutions and applications. In particular, the Bidoyng is a key tool in the management of Low Voltage transient faults. These faults are intermittent in nature and are often difficult to find and repair. The Bidoyng is used to both minimise the customer disruption associated with a fault (i.e. by automatic restoration of supplies) and to help engineers to locate the fault thus allowing proactive repair of the fault.

How the solution is delivering benefits

The Bidoyng smart fuse is a key enabling technology. It is being used as the main technology deployed on faulty parts of the LV network as part of the Fault Support Centre. In addition, it is providing information on the performance of the network to support the application of the Connect & Manage approach to domestic PV clusters connected to the LV network.

Connect & Manage of PV Clusters on LV networks

What the solution is

As a result of the learning outcomes of the LCNF Tier 1 Project – Low Voltage Network Solutions (LVNS), we have been able to successfully implement a streamlined approach to the connection of domestic scale PV systems to the LV network. These systems are often connected in clusters and can give rise to associated network voltage and thermal issues.

Traditionally, a network operator would require detailed and time consuming network assessments to be performed in advance of allowing the connection to proceed. These assessments are aimed at understanding if the connection could give rise to any of the aforementioned problems. However, as a result of the research that was undertaken as part of the LVNS project and the sophisticated network modelling that underpinned this allowed us to adopt an alternative approach.

We have successfully shown that up to a certain threshold (i.e. percentage of customers with PV systems) it is acceptable to allow the connections to proceed. Once the threshold is met however we will install network monitors to assess using actual recorded data if the network requires and further assessments.

How the solution is being used

The solution is being actively used across our network. We use this to avoid the often costly and time consuming network assessments that can accompany generation connections. We have established a business process supported by internal policy that provides for a continued monitoring of the PV volumes. Specific actions are triggered when these volumes are exceeded and follow up actions are performed as appropriate.

How the solution is delivering benefits

The solution delivers benefits to customers in the form of avoided waiting times associated with the connection of PV systems to the LV network. We have also been able to avoid expensive and resource intensive network connection studies, thus reducing internal costs and freeing up resources to concentrate of other parts of our connection services.

Use of the RIIO-ED1 CBA Tool
DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each solution reported in the Regulatory Year under report which are used to complete the worksheet must be submitted.

Capacity to Customers

The actual connections costs were the total of the connection cost for an n-0 solution paid by the customer for the four schemes connected at EHV. The benefits were calculated by assuming that the reinforcement would consist of simply looping in the supply with unit costs of £300 per metre and £200k for a primary switchboard change. It was also assumed that the customer would pay 100% of the additional costs as the increased security is wholly for their benefit.

Transformer Regeneration

This solution was based upon the baseline scenario of replacing or refurbishing all Grid and 33kV transformers which had a HI of 5 and refurbishing those with a HI of 4. The regeneration solution is to replace transformers at HI5 with a criticality of 2-4 and refurbish those at HI5 (critcality1) and HI4 (criticality 2-4). The costs used in the CBAs were derived from the CV3 and CV5 tables.

Fault Support Centre

The CBA was based on the number of LV ways fitted with reclosing devices during 2016-17, the number of times the devices operated prior to the fault being located and repaired, and the total number of customers interrupted by the recloser. It was assumed that faults occurred linearly throughout the week and therefore costs for the baseline case included premium time working. Each call out to replace a fuse was costed at three hours and it was assumed that customers would be without supply for 90 minutes.

Repairs were assumed to commence immediately as a fault became permanent. It was assumed that the installation of reclosing devices removed the requirement for fuse replacement and as supplies were restored within three minutes the Customer interruptions and customer minutes lost were reduced. The input from the FSC allowed faults to be located prior to becoming permanent and it was assumed that all faults were repaired during normal working hours. The cost of setting up the FSC was included in year 1 of the CBA.

Connect and Manage PV Clusters

The volumes used for this CBA were based upon the numbers of customers added to the Feed-in-Tariff database during 2016-17. For the baseline scenario it was assumed that there would be a requirement to purchase a tool for LV system analysis and that clusters of PV would consist of 24 properties covering 5% of the total. The remaining 95% would have on average 1.5 properties per application. Planning time was allocated at 12 hours per scheme for larger schemes and one hour for the small schemes. Solutions for the larger schemes were split between LV cable overlay (5%), transformer change (5%) and alter transformer taps (40%). It was assumed that for 50% of the larger schemes and all of the smaller schemes that the PV demand was approved.

The costs of network monitoring and design were calculated based on the predicted solar growth rates of PV installations, however these have reduced significantly since 2016 in line with the government cuts to subsidies relating to PV meanwhile other forms of DG are becoming more popular and widely used forms of generation.

For the connect and manage scenario it was assumed that 2% of the applications would lead to LV system monitoring being installed resulting in 2% of the total number requiring further planning of which 25% required a cable overlay, 10% required a transformer change and 65% required the tap position altering.

Demand Side Response – Catterall

Entering into a Demand Side Response contract which thereby defers the cost of reinforcement as it no longer required in order to comply with ER P2/6, although losses associated with not reinforcing the transformer will increase over time.

Power Saver Challenge

As this project is a 'proof of concept', no disposal of assets is included. No additional physical outputs will be delivered by the project. However, the project aimed to deliver sustained demand reduction in the Heatons area of Stockport, providing evidence that in other instances this will contribute to future delayed network reinforcement.

The learning and concept will be taken forward into this year's Network Innovation Competition (NIC) project 'Power Saver Plus'.

Changes to CBAs

If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, the DNO should include an explanation of what has changed and why the DNO is continuing the activity.

Updated CBA analyses continue to show positive NPVs for the Innovative solutions discussed.

Calculation of benefits

Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.

Capacity to Customers

The actual connections costs were the total of the connection cost for an n-0 solution paid by the customer for the four schemes connected at EHV. The benefits were calculated by assuming that the reinforcement would consist of simply looping in the supply with unit costs of £300 per metre and £200k for a primary switchboard change. It was also assumed that the customer would pay 100% of the additional costs as the increased security is wholly for their benefit.

Transformer Regeneration

This solution was based upon the baseline scenario of replacing or refurbishing all Grid and 33kV transformers which had a HI of 5 and refurbishing those with a HI of 4. The regeneration solution is to replace transformers at HI5 with a criticality of 2-4 and refurbish those at HI5 (critcality1) and HI4 (criticality 2-4). The costs used in the CBAs were derived from the CV3 and CV5 tables.

Fault Support Centre

The CBA was based on the number of LV ways fitted with reclosing devices during 2016-17, the number of times the devices operated prior to the fault being located and repaired, and the total number of customers interrupted by the recloser. It was assumed that faults occurred linearly throughout the week and therefore costs for the baseline case included premium time working. Each call out to replace a fuse was costed at three hours and it was assumed that customers would be without supply for 90 minutes.

Repairs were assumed to commence immediately as a fault became permanent. It was assumed that the installation of reclosing devices removed the requirement for fuse replacement and as supplies were restored within three minutes the Customer interruptions and customer minutes lost were reduced. The input from the FSC allowed faults to be located prior to becoming permanent and it was assumed that all faults were repaired during normal working hours. The cost of setting up the FSC was included in year 1 of the CBA.

Connect and Manage PV Clusters

The volumes used for this CBA were based upon the numbers of customers added to the Feed-in-Tariff database during 2016-17. For the baseline scenario it was assumed that there would be a requirement to purchase a tool for LV system analysis and that clusters of PV would consist of 24 properties covering 5% of the total. The remaining 95% would have on average 1.5 properties per application. Planning time was allocated at 12 hours per scheme for larger schemes and one hour for the small schemes. Solutions for the larger schemes were split between LV cable overlay (5%), transformer change (5%) and alter transformer taps (40%). It was assumed that for 50% of the larger schemes and all of the smaller schemes that the PV demand was approved.

The costs of network monitoring and design were calculated based on the predicted solar growth rates of PV installations, however these have reduced significantly since 2016 in line with the government cuts to subsidies relating to PV meanwhile other forms of DG are becoming more popular and widely used forms of generation.

For the connect and manage scenario it was assumed that 2% of the applications would lead to LV system monitoring being installed resulting in 2% of the total number requiring further planning of which 25% required a cable overlay, 10% required a transformer change and 65% required the tap position altering.

Demand Side Response – Catterall

Entering into a Demand Side Response contract which thereby defers the cost of reinforcement as it no longer required in order to comply with ER P2/6, although losses associated with not reinforcing the transformer will increase over time.

Power Saver Challenge

As this project is a 'proof of concept', no disposal of assets is included. No additional physical outputs will be delivered by the project. However, the project aimed to deliver sustained demand reduction in the Heatons area of Stockport, providing evidence that in other instances this will contribute to future delayed network reinforcement.

The learning and concept will be taken forward into this year's Network Innovation Competition (NIC) project 'Power Saver Plus'.

Cost benefit analysis additional information
Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.

C2C CBA RIIO ED1_v1.0.xlsx
Catterall DSR CBA RIIO ED1_v1.0.xlsl
LV fault management CBA RIIO ED1.v.1.0.xlsx
PV CBA RIIO ED1 FY18 v1.0.xlsx
TX Regen CBA RIIO ED1_v0.1.xlsx

E7 – LCTs

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

N/A.

LCT – Processes used to report data
(i) Please explain processes used to calculate or estimate the number and size of each type of LCT.
(ii) If any assumptions have been made in calculating or estimating either of these values, these must be noted and explained.

Secondary Networks

The number of secondary network low carbon technologies installed is maintained by our Data Management and Connections teams in various data bases.

LCTs Installed – Secondary Networks Heat Pumps

From the Data Management Heat Pumps database the number of heat pump units installed in 2016/17 was filtered from the Date Approved / Received with any blank entries not counted.

Using this filter the following volumes were identified:

9 units of total heat pump size of 65.78 kVA.

To convert the kVA to maximum export allowed in MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 0.06578 MW.

LCTs Installed – Secondary Networks EV Slow Charge (up to 16A/3.7kW draw-down)

From the Data Management SSEG database (EV NEW and HP & EV tables) the secondary networks EV slow charge units installed in 2016/17 was filtered by the Commissioning Year and then Size with any blank entries not counted.

From the EV NEW Table: 170 units (all 16A)
From the HP & EV Table: 2 units (all 16A)

Total 2016/17 = 172 EV slow charge units installed.

To convert the size to maximum export allowed in MW a draw down of 3.7kW for each 16A units was assumed to give a total of 0.6364 MW (172 x 3.7 / 1000).

LCTs Installed – EV Fast Charge (above 16A/3.7kW draw-down)

From the Data Management SSEG database (EV NEW and IDNO-EV'S tables) the secondary networks EV fast charge units installed in 2016/17 was filtered by the Commissioning Year and then Size with any blank entries not counted.

From the EV NEW Table: 414 units (26 x 20A, 137 x 30A, 236 x 32A, 12 x 40A, 2 x 64A and 1 x 200A)

Total 2016/17 = 414 EV fast charge units installed.

To convert the size to maximum export allowed in MW a draw down of 7kW for each unit was assumed to give a total of 2.898 MW (414 x 7 / 1000).

LCTs Installed – Secondary Networks PVs (G83)

From the Data Management SSEG database (SSEG, IDNO and SSEG + Battery tables) the PV units installed in 2016/17 was filtered by the Banding and then Date of Energisation with any blank entries not counted.

Using this filter the following volumes were identified:

Band 1.1 (Domestic CHP and all micro generation up to 1.5kW)

From SSEG tab: 235 units
From IDNO tab: 34 units

Total 2016/17 = 269 units installed.

For the 269 Band 1.1 units installed the total connected kVA was:

From SSEG tab: 265.245 kVA
From IDNO tab: 38.32 kVA

Total 2016/17 = 303.565 kVA.

To convert the kVA to maximum export allowed in MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 0.303565 MW.

Band 1.2 (Domestic CHP and all micro generation from 1.5kW single phase to 16A per phase, including 1 phase and 3 phase installations)

From SSEG tab: 3925 units
From IDNO tab: 19 units
From SSEG + Battery tab: 3 units

Total 2016/17 = 3 952 units installed.

For the 3 952 Band 1.2 units installed the total connected kVA was:

From SSEG tab: 11 885.45237 kVA
From IDNO tab: 56.06 kVA
From SSEG + Battery tab: 10.06 kVA

Total 2016/17 = 11 951.57237 kVA.

To convert the kVA to maximum export allowed in MW a conversion factor of 1 kVA = 0.001 MW was used to give a total of 11.95157237 MW.

For LCTs Installed – Secondary Networks PVs (G83) the total for 2016/17 was 4 214 units installed with an estimated size of 12.25513737 kVA.

LCTs Installed – Secondary Networks DG (non G83)

From the Connections Commissioned Generation database the number of units installed was filtered by connection voltage into secondary networks (up to and including 11kV).

This identified 169 units with a total plant capacity of 54.76702 MW.

Primary Network

LCTs Installed – Primary Networks DG (non G83)

From the Connections Commissioned Generation database the number of units installed was filtered by connection voltage into primary networks (33 kV and above).

This identified 8 units with a total plant capacity of 102.89 MW.

Assumptions

All EV fast charge (above 16A/3.7kW draw-down) was calculated taken using 7kw as the draw down.

The Electricity North West Limited definition of secondary (up to 11kV) and primary (33kV and above) networks was used to disaggregate between the types of networks connected onto.

LCT - Uptake
Please explain how the level of LCT uptake experienced compares to the forecast in your RIIO-ED1 Business Plan and the DECC low carbon scenarios. This must also include any expectation of changes in the trajectory for each LCT over the next Regulatory Year in comparison to actuals to date.

The volumes of LCTs installed has increased in 2016-17 from 2015-16 and is expected to contine to rise.

In our RIIO-ED1 Business Plan we concluded that the DECC Low scenario was the most probable estimate for our region over the period. The uptake in the first two years of the RIIO-ED1 period however is indicating an overall uptake at the end of the persio that is significantly below the forecast.