Environment Report 2017/18
Detailed Commentary Associated with the Annexes

Overview

This file contains the commentary associated with Annexes 1 to 7 to the Environment and Innovation 2017/18 report. In the context of the regulatory reporting process, the purpose of this commentary is to provide to the regulator, Ofgem, information supporting the data that we submit in the Environment and Innovation Reporting Pack (i.e. Annexes 1 to 7).

Annexes 1 to 7 and this associated commentary are an edited copy[1] of our annual submission to the regulator. The structure and content of this document reflect their specific purpose, and as a result are not suited for the reader looking for some general information. For that reader, we recommend the Environment Report.

Date of publication: October 2018

Associated documents:

- Environment Report 2017/18, Northern Powergrid, October 2018
- Annexes to the Environment report 2017/18, Northern Powergrid, October 2018
- Cost benefit analysis Tables, October 2018
- Regulatory Instructions and Guidance (RIGs) for RIIO-ED1,Ofgem, March 2016, available from: www.ofgem.gov.uk/publications-and-updates/direction-make-modifications-regulatory-instructions-and-guidance-rigs-riio-ed1

Content

[1] The edits consist in formatting changes to ease navigation and redaction of content that we agreed with the regulator were inappropriate for publication.

E1 – Visual Amenity

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
We have updated Table E1, where the workload refers to the undergrounding of overhead lines within or around the borders of national parks/areas of outstanding natural beauty. We are reporting 10.0km of overhead line removed in Northeast and 3.9km in Yorkshire during 2017/18. We have work programmes specifically used for recording costs and volumes of undergrounding work in our regions' designated areas, which allow us to separate the costs and activities of visual amenity from other undergrounding work. We have examined the circumstances of individual schemes to determine the correct voltage of the job and the relative amounts of overhead conductor removed and cable installed. Other assets involved with the work, such as the count of overhead services and poles removed and underground services installed have been noted in the asset register listing included in Table CV20. All the work undertaken is on either LV or HV overhead circuits. On examination of the schemes undertaken in 2017/18, we are able to confirm that all costs recorded arose from work carried out within the designated area. The schemes we have undertaken are within the boundary of the designated area concerned or are within the tolerance allowed.

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.
There have been no new designated areas created or extended in 2017/18 nor, to our knowledge, any change in the geographical size of any individual area.

E2 – Environmental Reporting

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
Table E2 provides volumetric performance statistics on the treatment of oil leakage and gas emissions alongside investments made in mitigating the effects of oil, SF_6 leakage and noise pollution. *Cost and Volumes categories* • The fact that we have a relatively low level of absolute expenditure reported in E2 should be seen in the context of the overall investment made and benefits achieved in asset replacement (where the replacement of fluid-filled cables are reported), in flooding and in asbestos mitigation projects. • The work reported in Table E2 has a specific environmental investment driver, and in 2017/18 we have undertaken schemes addressing noisy equipment, with work in both HV and EHV substations (see section on noise mitigation

below), on mitigating oil pollution, through remedial work on transformer bunds and installing spills kits at our major substations and also some work on SF6 gas emissions.

- During 2017/18, we have reported costs on three Yorkshire overhead line schemes where we have been faced with significant excess costs associated with treatment of land contaminated by the impact of our apparatus (Woodhouse Masts).

    - Harrison Lane-Slaithwaite 33kV
    - Brighouse-Spenborough 33kV
    - Ferrybridge-South Elmsall 66kV

    The requirement arises during the recovery of these steel masts. Whilst we undertake the work in our EHV Overhead Line portfolio, it was discovered that they were coated in lead paint, which contaminated the soil underneath the offending apparatus. The additional costs in dealing with the land contamination relating to three projects: removing the contaminated the soil, reinstatement and damages etc. have been applied to the contaminated land category in Table E2.

- This year we also completed a scheme in our Yorkshire area where we carried out refurbishment work to the switchgear at six sites, where we have had SF_6 gas leakage issues.

Volumetric Measures

- Table E2 also includes a number of categories, against which we record Northern Powergrid's environmental performance.
- We recorded 8 incidents requiring reporting to the Environment Agency (none of the incidents resulted in civil Sanction): 1 in Northeast and 7 in Yorkshire in 2017/18. These all relate to fluid filled cables. All incidents were appropriately addressed in consultation with the Environment Agency.
- On SF6 leakage, Table E2 records SF_6 emitted as a proportion of the total gas bank. We have updated the amount of our overall gas bank with the net asset additions in each licence. We have also applied the amount of gas emissions, which we record on our source systems, and the table calculates a gas emitted ratio of 0.22% in Northeast and 0.32% in Yorkshire in 2017/18. This represents an improvement in our performance in Yorkshire but not in the Northeast. However our recent purchase of an SF_6 camera will enable us to further reduce our SF_6 loss in both licence areas.
- Moving on to the fluid used statistics; we record circuit kilometres, oil fluid litres and the amounts of oil top ups and recoveries. In order to calculate the fluid totals, we calculate the average value for litre per km for each cable core and voltage, taking account of a range of variables, including cable type, cable manufacturers' specifications and different types of site works. We have taken the circuit lengths of oil-filled cable at each voltage, using data taken from the

asset register.

- We have also reported the audited values for net fluid used for top ups and fluid recovered that are recorded on our source systems. When these are entered on to Table E2, the result is that our ratios of fluid tops ups to the total in service is 0.9% for Northeast and 1.6% for Yorkshire in 2017/18. This represents an improvement in our performance in both the Northeast and Yorkshire. *We are satisfied with this result as it vindicates our actions and strong performance in removing oil filled cable*.

DNOs must provide some analysis of any emerging trends in the environmental data and any areas of trade-off in performance.
The overall number of environmental events (those reportable to the Environment Agency and those that fall outside this category) has reduced since 2012 from 97 in the 2012/13 regulatory year (Northeast and Yorkshire) to a flatline 64 in both the 2014/15 and 2015/16 regulatory years, reducing further in the 2016/17 regulatory year to 53 and again to 41 in the 2017/18 regulatory year. Changing weather patterns play a large role in this trend as the number of direct lightning strikes on equipment causing environmental events has dropped in the same time period. Fluid loss continues an overall downward trend and gas loss continues to be stable.

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.
We have completed the row in Table E2 relating to noise complaints and have provided the number of calls relating to noise complaints on our calls systems. Of those calls, there are a number that result in formal complaints that remedial action in terms of mitigation schemes that are reported in Table E2. We completed four schemes in 2017/18; three in Northeast and one in Yorkshire. Noise complaints are considered objectively, by performing site surveys and measuring sound levels across the audible spectrum at various points in the area the complaint was raised. A noise complaint is justified if specified noise levels, especially in the 100Hz range, are exceeded. We examine each case in detail: this involves staff attendance at the site, taking the necessary readings and making an assessment of the best means of dealing with the nuisance. A variety of mitigation solutions are possible: acoustic doors, acoustic roof panels, acoustic louvres, anti-vibration pads – but we have faced situations where poor ventilation or restricted space between substation doors and the electrical equipment inside does not allow us to install the acoustic solution (indeed these sometimes might pose a risk as a climbing aid). In those circumstances we are left with re-siting the equipment (for pole mounted transformers) or full replacements, where we also have to consider synergies with other requirements for asbestos or opportunities for reinforcement or indeed planned asset replacement at the site. Any work at primary sites is, by the very nature of the assets being treated; a much more specialised, complicated and expensive exercise and as such, noise complaints involving primary sites can take time to resolve. For the reporting year, we are reporting four completed schemes and in brief, the circumstances are as follows:

In the Northeast, a noise complaint was upheld in relation to the sound levels emitted by a transformer at Haxby Road EHV primary substation in York. As a result of the acoustic measurements taken on site, we have installed an acoustic enclosure. The works involved: designing and manufacturing the screens, carrying out the civils work (foundations, footings and enabling access) to install the acoustic screens and installing the enclosure.

In a similar case at our Temple Park primary substation in South Shields; we have installed an acoustic enclosure to two transformers. This case was more extensive than the first and there were also additional costs to allow access to the tap changers, to clear a large volume of contaminated gravel and to provide additional fire proofing because of the proximity to nearby houses. It is perhaps our most significant civils project, of any type, that we have undertaken during the year.

Finally in the Northeast, we installed an acoustic screen around one transformer at our Prissick Primary substation in Middlesbrough following a noise complaint that was upheld. For this project, we faced additional costs due to the size of the screen, the foundations needed to be larger and more robust than usual for a scheme of this type.

The important feature about these three cases is that we were working at an EHV substation where a large acoustic enclosure was required for each project. The costs of such schemes are considerably higher than projects at distribution substations, where the noise issue is usually solved by replacing the offending transformer.

Our case in Yorkshire provides an example of a case at an HV substation, but it too proved to be a complex and relatively high cost job, involving costs in Asset Replacement, Reinforcement as well as Noise Reduction. The substation concerned was our 11kV substation at Temple Crescent in Rotherham. The brick building provided insufficient acoustic damping and following a complaint of transformer noise and the subsequent investigation which confirmed the problem, a solution has been sought. We decided to re-locate the substation since the footprint of the existing site did not allow for the installation of a modern UDE in an acoustic enclosure. We were also able to take advantage of a coincident requirement for plant replacement (since the switchgear had become obsolete) and a substantial reinforcement element involved to facilitate the work, to transfer the load from the old substation, which was demolished.

In addition to these completed schemes we have five schemes in Northeast and seven in Yorkshire where we are intervening with physical noise abatement measurers or have firm plans to do so. Nearly all of these are in HV substations. Our teams do not always need to intervene physically, but we show our commitment by taking the necessary readings and liaising with the customer and are able to provide evidence to demonstrate that our equipment is not causing a nuisance. An example was at our substation in Silksworth Common, Barnsley, where we were able to provide a report to the local Environmental Health Officer (EHO), who agreed for us to close the enquiry.

There are some potential difficulties with developers submitting plans for housing developments near our premises. We are liaising and holding discussions with local EHOs, where we are approaching all Local Authorities, requesting them to apprise us of planning applications on land adjacent to our assets. Our intention is that future noise complaints and issues associated with hot sites can be avoided or costs associated with mitigation be picked up by the developers. We

currently have submitted objections against plans to develop land next to our primary substations at Scunthorpe North (Yorkshire) and at Prissick (Northeast and the subject of one of expensive schemes highlighted above). We feel that there is a likelihood of our submitting similar objections on grounds of noise at Darlington East (Northeast) and Wheatley Park (Yorkshire) Primary substations. Once the new homes have been built close to our apparatus, we believe there could be an associated risk of noise pollution.

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
We can confirm that we have no non-undergrounding visual amenity schemes to report.

Any Undergrounding for Visual Amenity should be identified including details of the activity location, including whether it falls within a Designated Area.
No work has been undertaken other than in work specifically that specifically under the Visual Amenity programme. All the workload is identified on Table E1.

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.
We recorded 8 incidents requiring reporting to the Environment Agency (none of the incidents resulted in enforcement actions or penalties); one in the Northeast and seven in Yorkshire in 2017/18. Seven of the incidents related to fluid filled cables and one was associated with an attempted theft at a primary substation. All incidents were appropriately addressed in consultation with the Environment Agency.

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.
We are certified to ISO14001:2015 and have been subject to two surveillance audits audit during the regulatory year under report. No major non-conformances were identified.

DNOs must provide a brief description of any permitting, licencing, registrations and permissions, etc. related to the activities reported in this worksheet that you have purchased or obtained during the Regulatory Year.
We have three bespoke permits and one standard oil-only permit. We are a registered upper tier waste carrier, broker and dealer.

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.
We have carried out Gas and Oil Pollution Mitigation Schemes during 2017/18. Firstly, we have a programme engaged in the treatment of transformer oil bunds at major substations. Our strategy is not to install full bund replacements until all existing bunds have been subjected to appropriate remedial works to remedy defects as there will be a greater benefit per £ value realised and indeed earlier benefit in terms of reduced oil leakage and environmental clean-up at our sites. We have therefore concentrated on bund refurbishment, which includes the replacement / repair of bund pumps. Secondly, we install and replenish oil spills kits at substations, where there is a heightened risk of or requirement to deal with oil leakage. The kits provide a

temporary measure until the leaks can be resolved or the plant replaced and contain all the equipment required for site staff to use should an oil leak occur.

As we noted earlier, we have also undertaken remedial work at Yorkshire sites to repair switchgear subject to SF_6 gas leakage. The driver behind this work was our commitment to react directly to the worsening of our gas emissions total in the last two years.

We have reported four oil mitigation schemes in Northeast and four in Yorkshire in 2017/18, and six SF_6 mitigation schemes in Yorkshire.

We have now completed the third workstream that was driven by Environment Agency Pollution Prevention Guidelines, PPG 21. Both our Northeast and Yorkshire sites have detailed drainage plans which are available in the event of an incident such as an oil spill or fire.

Whilst we seek to protect and prevent interference as our top priority, it is recognised that the management of incidents is an inevitable outcome and therefore pollution containment measures are essential in reducing environmental, financial and reputational damage to Northern Powergrid. To ensure effective remediation we have a 24 hour environmental response support contract in place to attend for any and all environmental incidents as required.

E3 –BCF

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
Data entry is in the form of base measurement and conversion factors. Such factors are published by DEFRA in place on 31 March of the regulatory period being reported. Where multiple conversion factors were required to calculate BCF within a particular category (e.g. due to use of both diesel and petrol vehicles), a weighted average of these factors has been entered. Variations in volume of each fuel type between the Northeast and Yorkshire will result in different weighted average conversion factors for similar categories. E.g. in Yorkshire a lower quantity of petrol was used for business transport and a larger quantity of diesel was used. Therefore the resultant overall weighted average conversion factor for this category for Yorkshire will be different to that of Northeast. All Contractor figures are actual returns. No estimates have been made.

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.
All figures relate to the activities of the regulated business. All data is collected in a form where it is attributed to one of the licensed distribution businesses.

Corporate categories are allocated on a 50:50 basis.

Business travel by bus, taxi, or ferry has not been included as it believed not to be material.

Refrigerant gas loss from air conditioning units has not been included. The amount is not believed to be material.

Energy use at substations has been estimated.

The company is audited on an annual basis to ensure compliance with the ISO 14064-1:2006 standard. This tests the management, reporting and verification of our greenhouse gas inventory.

BCF process

The reporting methodology for BCF must be compliant with the principles of the Greenhouse Gas Protocol.[2] 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.

To maintain consistency and comparability, the figures for 2016/17 have been re-stated as one of the contractor figures provided last year was found to be incorrect and it artificially inflated our BCF figures by 18,437 tCO_2e.

All variations and resulting change in BCF (tCO_2e) are outlined in the following tables:

BCF Variation 2016/17 NPGY

		2017 Original Volume		2017 re-stated		Variation	
Contractor Emissions:		Volume	tCO2e	Volume	tCO2e	Volume	tCO2e
Operational Transport	Road	4,626,395.99	11,965.46	1,802,392.73	4,590.29	-2,824,003.26	- 7,375.17

		2017 Original Volume		2017 re-stated		Variation	
Contractor Emissions:		Volume	tCO2e	Volume	tCO2e	Volume	tCO2e
Fuel Combustion	Diesel	1,809,251.26	4,725.04	1,809,251.26	4,725.04	-	-

BCF Variation 2016/17 NPGN

		2017 Original Volume		2017 re-stated		Variation	
Contractor Emissions:		Volume	tCO2e	Volume	tCO2e	Volume	tCO2e
Operational Transport	Road	7,731,362.15	20,067.22	3,495,356.75	9,004.47	-4,236,005.40	- 11,062.75

		2017 Original Volume		2017 re-stated		Variation	
Contractor Emissions:		Volume	tCO2e	Volume	tCO2e	Volume	tCO2e
Fuel Combustion	Diesel	1,501,781.72	3,922.05	1,501,781.72	3,922.05	-	-

[2] 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 Department for Environment, Food & Rural Affairs 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 Department for Environment, Food & Rural Affairs unless there is a compelling case for using another conversion factor. Justification should be included for any deviation from Department for Environment, Food & Rural Affairs 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.

Building energy usage

- Data from electricity and gas bills relating to all the licensee's non-operational properties is collated by the facilities department. For non-half-hourly metered bills, the amount included is that billed in the quarter even if based on an estimated reading. A small number of buildings that are owned by a landlord are excluded. For gas the conversion factor for gross calorific value has been used.
- Own use at substations has been estimated for 2017/18. The figures have been built bottom up from the various components (heating, lighting, etc.), although the contribution of each component is an engineering judgement rather than a direct or sample measurement.

Operational Transport

- The main source of fuel reported here is used by the company's fleet, and data is collected from company fuel card use. Figures are collated for petrol, diesel, and LPG (when used).
- We also report volume of fuel stored onsite to fill the forklifts and logistics HGV vehicles.
- Other usage of fuel includes that used by contractors for their fleet and generators. Data on contractors' usage is compiled from returns sent in response to a request. See comments under Contractors.

Business Transport

- Business transport - road

Data is collected from business miles claimed by staff monthly on their expense claim forms. The data is split between diesel and petrol according to the information provided on the claim forms. Corporate staff mileage is split 50:50 between licensees (to reflect the fact that such travel is undertaken on behalf of

both licensees equally).

- Business transport – rail and air

Data from staff travel requests is transferred to a spreadsheet where the mileage for each journey is calculated and then collated according to rail, domestic flights, short-haul international, and long-haul international. As mentioned above, figures relating to corporate staff are attributed 50:50 between licensees.

Fugitive Emissions

These figures are the same as those used in Table E2 and are the SF_6 emissions from the network.

Fuel combustion

This is the fuel used for generators by our contractors.

Losses

- This data stream uses the figures derived under the Balancing and Settlement Code arrangements and reported regularly to Ofgem. The volume of energy is converted in tonnes of carbon dioxide using the "Electricity – generation" (scope 2) factor provided by DEFRA.

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.

Contractor figures are derived from actual returns provided by contractors utilised to undertake work on behalf of Northern Powergrid.

Our contractor figures are in-line with previous years.

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.

Own use at substations has been estimated for 2017/18. The figures have been built bottom up from the various components (heating, lighting, etc.), although the contribution of each component is an engineering judgement rather than a direct or sample measurement.

E4 – Losses Snapshot

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

E4 includes:
• Activities where the costs incurred principally relate to managing Distribution Losses.
  ○ In practice at this time this will be restricted to actions to deal with Relevant Theft of Electricity as we have no other investments solely to reduce losses.
• Activities where some of the costs incurred relate to managing Distribution Losses (but where losses are not the principal reason for the expenditure) excepting activities that may help to manage losses but where Distribution Losses are not associated with the DNO's decision to undertake the activity and where any losses benefits are purely coincidental:
  ○ At present this is restricted to 300mm^2 cable at LV and 11kV
  ○ Our losses strategy also includes distribution transformers and primary transformers, however Ofgem regarded these initiatives as producing coincidental loss reductions at the RIIO-ED1 review and they are therefore excluded from the E4 returns.
 	
<u>Costs</u>
Total costs are taken from the overall unit cost for cable replacement, multiplied by the cable lengths installed.
The differential between the 300mm^2 cable and 185mm^2 cable is known and together with the lengths of each type and the overall unit cost can be used to calculate a unit cost specific to each type.
This calculation is done for Northeast and Yorkshire and for 11kV cable and LV cable, giving four cost lines in total.
Incremental costs associated with the losses initiative are taken from the CBA cost per meter and the volumes of 300mm^2 cable.
 	
<u>Volumes</u>
Total cable volumes and 300mm^2 cable volumes are taken from work undertaken for the RRP asset additions submission. An assumption has been made that 20% of the 300mm^2 would have been this size in any case.
 	
<u>Losses benefits</u>
Losses benefits (MWh) associated with the losses initiative are taken from the CBA losses benefit per meter and the volumes of 300mm^2 cable.
 	
<u>CBAs</u>
The CBAs are based on the submitted RIIO-ED1 CBAs reviewed in line with the financial data (WACC) from the ED1-RIIO settlement and actual cable lengths involved.
By entering the actual cable lengths in the actual year of installation in the Ofgem CBA and altering the output table on the option calculation sheet to eight years this can be made to calculate a RIIO-ED1 benefit and a 45-year benefit.

Programme/Project Title Please provide a brief summary and rationale for each of the activities in column C which you have reported against.
The benefits of low loss design have usually been in the form of oversizing conductors (relative to existing utilisation levels), which can have the added benefit of improving network performance (i.e. voltage drop, current carrying capacity and earth loop impedance).

LV cable *oversizing*
At low voltage (230/400V), the use of 300mm^2 aluminium cables has been adopted as standard cable size for all mains other than spurs carrying less than 120A per phase in line with our RIIO-ED1 business plan submissions.

11kV cable *oversizing*
At 11kV the use of 185mm^2 aluminium has been adopted as a standard network feeder size, with 300mm^2 aluminium used for the first leg from the primary substation and highly loaded feeders. Going forward, and in line with our RIIO-ED1 business plan submissions we will implement the policy of installing a minimum cable size of 300mm^2 at 11kV where practical (e.g. if bending radii and termination arrangements allow).The use of 95mm^2 is only recommended in special circumstances, as it becomes uneconomical in terms of lifetime losses at greater than 100A peak loading.

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

Cables are replaced or installed as part of activities such as asset replacement, reinforcement, connections, visual amenity and faults volumes. These are the primary drivers

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

The baseline scenario assumed each metre of cable actually installed as 300mm^2 was installed as 185mm^2.
Volumes were restricted to 300mm^2 cable which would otherwise have been 185mm^2. Any cable actually installed at a smaller size or that would have been the larger in any event was excluded.
On the CBA, only incremental costs were included so the baseline was a blank sheet.

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.

Ofgem's version 4 CBA from the RIIO-ED1 business plan submissions was used. This is understood to be Ofgem's current version.
All CBAs show that one year of investment has a positive benefit over 45 years as shown in the table below.

	NPVs based on payback periods following one year investment (£m)			
	8 years	24 years	32 years	45 years
Overlaying LV cable with 300m^2 wf (NPgN)	-£0.003	£0.06	£0.15	£0.192
Overlaying LV cable with 300m^2 wf (NPgY)	-£0.002	£0.09	£0.23	£0.29
300m^2 for all 11kv network feeders (NPgN)	-£0.02	-£0.01	£0.00	£0.01
300m^2 for all 11kv network feeders (NPgY)	-£0.08	-£0.05	£0.02	£0.05

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.

A summary of the CBA tables are included in this report.

E5 – Smart Metering

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

Worksheet E5 records the following information:

- Pass-through Smart Meter Communication Licensee Costs and Smart Meter Information Technology Costs, plus Elective Communication Services costs that are outside of the price control, and

- DNO's estimates of the benefits of smart metering for domestic and non-domestic customers using the categories set out in DECC's January 2014 Impact Assessment.

Commentary regarding pass-through Smart Meter Communication Licensee Costs and Smart Meter Information Technology Costs, plus Elective Communication Services that are outside of the price control:

Smart Metering Communication Licensee Costs consist only of the monthly charges levied by the Data Communications Company (DCC). These are recorded against dedicated account codes in our financial recording systems allowing us to separate these costs from any other cost items.

We have not incurred any Elective Communication Services costs. These costs are payable to the DCC in respect of Elective Communication Services, which include services to or from a Smart Metering System that relate solely to the Supply of Energy (or its use), and services that are provided by DCC pursuant to a Bilateral Agreement (rather than the DCC User Interface Services Schedule).
The DCC did not enter into any Bilateral Agreements for 2017/18.

In 2016/17 our Smart Metering Information Technology Costs covered the cost of implementing our core smart metering IT user gateway (being the IT system used to connect to the DCC) plus a number of additional items, which were included in the revised definition of Smart Meter Information Technology Costs

introduced in V3.0 of the RIIO-ED1 regulatory instructions and guidance.

These additional items were:

- The marginal cost of improving the resilience and security of computer rooms.
- The planning and development of new and improved business processes that either on a stand-alone basis, or in conjunction with existing IT applications, will use smart metering data to deliver DNO benefits from smart metering.
- The costs associated with the provision of Registration Data Provider (RDP) service specifically associated with initial set up associated with DCC Live R1.2, plus costs associated with the ongoing provision of RDP service on an ongoing basis.

In 2017/18 we have continued to be guided by the revised definition of Smart Meter Information Technology Costs, which is substantially unchanged from 2016/17. Our 2017/18 Smart Metering Information Technology Costs consequently include:

- The cost of the continuing implementation of our smart metering IT user gateway up until our go-live on DCC Release 1.2 in November 2017
- The cost of smart metering IT user gateway software and hardware support and maintenance
- The cost of maintaining a Registration Data Provider (RDP) service
- The cost of upgrading our smart metering IT user gateway to work with DCC Release 1.3

The cost of integrating our smart metering IT user gateway with our customer relationship management system in order to allow our Contact Centre agents to see smart metering outage alerts from within CRM and to check the supply status of a smart meter.

The implementation of our IT user gateway and the integration of this gateway with our customer relationship management system are both stand-alone capital projects allowing us to record the costs of each activity separately from the costs and activities of other smart metering and non-smart metering activities.

IT user gateway software and hardware support and maintenance costs have been taken directly from invoice values, with the only allocation and apportionment having been the division of the invoice value by 12 (to identify a monthly cost) followed by the splitting these costs equally between our two licences.

RDP costs have been taken directly from invoice values; hence no estimation, allocation or apportionments have been undertaken save from splitting these costs equally between our two licences.

Commentary regarding DNO's estimates of the benefits of smart metering for domestic and non-domestic customers using the categories set out in DECC's January 2014 Impact Assessment:

Smart Metering Estimated Benefits for the 2017/18 regulatory year are nil.

This is because each of the seven benefit categories set out in DECC's Impact Assessment require smart metering data to be provided to us by the DCC as an essential input to the delivery of benefits.

No reliable data has yet been made available by the DCC. The reason for the absence of data is that as at the end of the 2017/18 regulatory year the number of smart meters installed by suppliers in our area and linked to DCC systems was negligible (at circa 30). Furthermore the dependability of communications and alarms and alerts coming from these meters is unproven.

We do not yet have access to half-hourly consumption data, upon which some of the seven benefits categories depend. In order to be able to access such data we need to produce a Data Privacy Plan and then have this accepted by Ofgem. Our plan has not yet been submitted for consideration because following our discussions with Ofgem personnel at the close of 2017 (regarding the submission timescales for our plan) it was indicated that we should wait until the response to Western Power's submission was published before submitting our own Data Privacy Plan.

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 expenditure reported under Smart Meter Information Technology Costs has being used to implement, support and maintain our IT user gateway; to provide our RDP service; and support the integration of our smart metering IT user gateway with our customer relationship management system.

- The expenditure on our IT user gateway allows us to receive smart meter alerts, execute service requests that send commands to smart meter devices, and execute service requests that send commands to the DCC. The IT user gateway system is as an essential enabler for the delivery of smart meter benefits.

- The expenditure on our RDP service supports the wider smart metering programme's security model by providing details to the DCC of each of our customer's registered suppliers.

- The expenditure being used to fund the integration of our smart metering IT user gateway with our customer relationship management system will provide our Contact Centre agents, whilst speaking on the telephone to our customers, with visibility of any smart metering outage alerts relating to the customer's premises and to check the supply status of a smart meter at those

premises.

No non-elective data has been procured from the DCC.

No Elective Communication Services have been procured from the DCC.

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.

Smart Metering Estimated Benefits for the 2017/18 regulatory year are nil.

This is because the RIGs require us to estimate "gross financial benefits delivered in the Regulatory Year from the use of smart metering data" against each of the seven benefit categories set out in DECC's January 2014 Impact Assessment.

The minimal number of SMETS2 smart meters connected to the DCC in our territory (circa 30) and the immaturity of communications with these meters means that data coming from these meters is not yet reliable.

Furthermore we do not yet have access to half-hourly consumption data having been advised to wait until the response to Western Power's submission was published before submitting our own Data Privacy Plan.

As such no meaningful smart metering data, from which benefits could realistically be derived, has been available to us in 2017/18.

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 are 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.

The Regulatory Instructions and Guidance published by Ofgem in April 2016 planned for a working group to be established to clarify instructions and guidance on:

- the definition of a unit for different solutions
- consistency in reporting of Innovative Solutions definitions
- consistency in reporting methods with regards to impacts.

Since the working group has not yet been formed, we have followed the guidance in the RIGs, responded to informal feedback from Ofgem and made assumptions that are explained in the commentary below.

In previous years, we have reported on five areas which we have now ceased to report on:

- Load capacity release
- Generation capacity release
- Telematics in operational vehicles
- Fire retardant workwear
- Farm safety

We believe these are innovative and are continuing to provide benefit. However, we understand that Ofgem have ruled that they do not meet the specific definition of "Innovative Solutions" employed for the purposes of regulatory reporting.

If Ofgem revise this guidance we will provide benefits for these lines.
We have not removed the 2015/16 and 2016/17 benefits for these lines as these have been accepted previously.

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 have been calculated, including what assumptions have been relied upon.

Increase Network Capacity/Optimise Utilisation

Voltage Reduction – We have started to receive complaints of high voltage on our network as the amount of embedded generation increases. Our programme of reducing the set point voltage at 11kV busbars of our primary substations is benefitting this situation. This is the first step in a revision to our voltage control policy which is being amended as a result of the learning from the CLNR project. The basic assessment involved determining whether the tapping range at the substation is adequate for the expected load flows and voltages on the network, whilst still leaving room for an OC6 voltage reduction. The assessment assumed that the reduction in statutory voltage limit on the LV network (from 225.6V to 216.2V) would provide the necessary voltage leg-room to lower the target voltage at the primary substation by 200V. Reducing the target 11kV voltage by

200V results in a voltage reduction of approximately 4.5V at the LV terminals of a distribution transformer. During 2017/18 we reduced the set point voltage at a further 82 primary substations. These actions are designed to create the voltage headroom to cater for the connection of PV without creating voltage complaints. It is estimated that these actions release sufficient voltage headroom to connect an additional 9MVA of distributed generation such as domestic solar PV to the LV network fed from each primary substation; 738MVA across the 82 primary substations addressed in 2017/18.

HV automation

We are currently rolling out Automatic Power Restoration System (APRS) across our High Voltage distribution network. This has been deployed across 35 primary substations in 2017/18; 22 in the Northeast (running total 55) & 13 in Yorkshire (running total 55). It is designed to identify and isolate faulted sections of the network and then restore healthy sections of network within 3 minutes. This restores supplies to many customers automatically and also enables fault restoration/repair staff to be directed towards the faulted section of network more quickly, both of which enhance the customer experience.

LV Technology Programme

We have implemented a pro-active approach to LV network intermittent faults by use of new technology that was previously developed under an ENW IFI project with Kelvatek. This centres on the concurrent deployment of 1010 smart LV devices on the LV network. The intention is to restore intermittent (Non Damage) faults within 3 minutes and thus enhance customer experience. Over time, this allows the pro-active location and repair of persistently active intermittent faults before customers experience a longer, permanent unplanned interruption (Damage Fault). These devices improve customer service and reduce costs associated with service failures as well as reducing overtime payments due to the ability to programme fuse replacements in normal working time.

Improve asset life cycle management

HV circuit breaker retrofit - Retrofitting refers to the replacement of the moving portion and its carriage with a modern equivalent. The fault current interruption medium used in recovered units is likely to be oil; the replacement units will typically employ a vacuum to extinguish the arc.

Retrofitting extends the asset life significantly and provides network performance benefits with reduced capital investment compared to replacement.

The replacement of a complete switchboard would normally require an off-line build, involving the construction of a new switchroom adjacent to the existing building. This option presents significant building, civil and cabling costs and adjacent land may not be available. Retrofitting mitigates the most significant risks associated with the existing switchboard, but retains the fixed portion and associated cabling, auxiliary wiring and instruments, thus incurring significantly lower capital investment.

The contract for the manufacture and installation of HV retrofit circuit breakers was awarded in Q3 2017. In the last 12 months, site surveys have been undertaken and orders placed for delivery in Q3 2018. No units have been delivered to date. The 2015 Asset Serviceability Review identified 258 circuit

breakers for retrofitting during RIIO ED1.

Transformer insulating oil regeneration - Acidity and moisture are products of the degradation of the insulation systems and their presence will accelerate the further deterioration of the paper insulation. Treatment of the insulating oil to remove acidity and moisture will extend the transformer life significantly.

On-line regeneration of the oil has significant benefits over an oil change including:

- More effective removal of particles and sludge;
- Longer term improvement of the insulating oil;
- Negates the need to drain the transformer;
- Negates the need to pull a vacuum on the transformer;
- Significantly reduces the quantity of insulating oil that needs to be transported to site and reduces the associated safety risk and cost; and
- Overall reduction of Northern Powergrid's carbon footprint.

Life extension of the transformer will only be realised if all the components of the unit remain serviceable. Oil regeneration shall only be undertaken following an assessment of tap changer serviceability and main tank integrity, and subject to satisfactory oil dissolved gas analysis results. The 2015 Asset Serviceability Review identified 47 transformers for refurbishment (which will include oil regeneration in the majority of cases) during RIIO ED1.

Improve Environmental Impact

We deployed PFT leak detection techniques to successfully locate and repair seven EHV fluid filled cable circuits in 2017/18 (11 in Yorkshire and none in the Northeast). The time saved to locate these leaks, compared with traditional dig and freeze technique, saved approximately 8,250 litres of cable fluid that would otherwise have been lost into the ground. Location using PFT is quite an expensive technique and, whilst it does not actually deliver any significant cost savings relative to the traditional technique, it does reduce the number of excavations required and so reduces the impact of the leak location and repair activity on the local environment in terms of street-works disruption. The increased speed of leak location and reduced fluid loss also enables us to restore full network security more quickly and reduces the risk of prosecution under environmental legislation. We currently have a prioritised programme for a fluid exchange programme to add PFT to all leaking 132kV and EHV fluid filled cables so that as soon as the leak rate reaches threshold values we able to achieve a very rapid location and repair due to the fact that the cable already contains the PFT and the location only needs a leak location survey.

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.

It should be noted that none of the initiatives reported in this return were initially justified by using the Ofgem CBA table. The information in our own CBAs has therefore been transcribed into the Ofgem CBA as best as reasonably practicable.

Any expenditure incurred in 2016, for benefits realised in 2017 and projected beyond 2017, has been shown as 2017 expenditure. CBAs have been completed

in this way for the following items:

- LV technology programme (Bidoyngs)
- HV automation (APRS)
- Cable fluid leak location

We have not completed CBAs for capacity recovery or constrained generation. For capacity recovery, the costs are quite low but the payback can be quite random. For constrained generation connections, the CBA really lies with the connectee who has to consider the risks of occasional constraints on future cash flows vs. the reduction in connection costs that can be achieved through these arrangements.

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.

N/A

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.

Voltage Reduction – The benefits for generators, as a result of lowering the target 11kV (or 20kV) voltage at the primary substation will vary depending upon the local network topology. We have undertaken a desktop study of 65 existing LV feeder to identify the potential increase in generation export capacity if the voltage at the distribution substation was lowered.

Lowering the LV bar at a 11,000/400V distribution substation by 4V (from 252V to 248V) the average export capability per household increases significantly but the starting and revised export capability varies significantly by network, as follows:

	No. of customers on feeder	Max kW generation per customer at 252V	Max kW generation per customer at 248V	Total kW permitted generation at 252V	Total kW permitted generation at 248V
Average	*46*	*0.88*	*4.40*	*26.00*	*129.80*
Max	*106*	*3.18*	*15.86*	*59.66*	*298.30*
Min	*14*	*0.07*	*0.34*	*6.09*	*29.58*

From the above studies, the average increase in permitted generation export is 3.5kW per customer. However, after accounting for voltage rise in the HV network it would be prudent to reduce the expected increase in capability to, say, 1.5kW per customer.

Northern Powergrid has 654 primary substations and 3.96 million customers. With an average of 6,050 customers per primary substation, the average increase in LV generation capacity is estimated to be 9 MW per primary substation.

For the 82 primary substations completed in 2017/18, the expected increase in generation capacity is therefore approximately 738 MW.

HV automation **(APRS)** - For CI, the benefits are taken directly from the number of customers whose supplies were restored within three minutes. For CML, the counterfactual is based on long-run historical fault data, which shows that remote switching from the control centre took, on average, five minutes.

	NPVs based on payback periods following one year investment (£m)			
	16 years	24 years	32 years	45 years
HV automation (APRS)	2.18	1.90	1.72	1.54

Transformer insulating oil regeneration – Oil regeneration is expected to increase the residual service life by 10 years if it is undertaken with around 10 years residual service life remaining – i.e. it increases residual service life from 10 years to 20 years.

	NPVs based on payback periods following one year investment (£m)			
	16 years	24 years	32 years	45 years
Oil regeneration	-1.44	-5.15	-10.73	-15.59

***LV Technology Programme* (Bidoyngs)** – Estimate of CI / CML savings on substations where the Bidoyngs have been located and successfully operated on an intermittent fault, calculated from the avoidance of an over 3 minute interruption. An estimate of avoided overtime due to a reduction in fuse replacements during overtime and a reduction in EGS2 payments due to better fault location information reducing restoration times on permanent faults.

	NPVs based on payback periods following one year investment (£m)			
	16 years	24 years	32 years	45 years
LV Technology Programme (Bidoyngs)	2.70	1.64	0.94	0.23

Fluid filled cable leak location - In table E6 we have included the actual cost of PFT treatment on the 11 circuits to which it was applied in 2017/18 and have shown the avoided costs to be the same[#]. The oil leakage benefit is calculated from the average leak location timescale being reduced from 28 days to 3 days. This 25 day saving is multiplied by the average leak loss per day to give the fluid loss benefit. For the eleven circuits in 2017/18 the approximate saving in fluid loss due to the PFT method of location was 11 circuits * 30 litres per day * 25 days quicker location = 8,250 litres; 8,250 litres for the 11 cables in Yorkshire.

	NPVs based on payback periods following one year investment (£m)			
	16 years	24 years	32 years	45 years
Fluid filled leak location	0.05	0.05	0.05	0.05

(# The PFT treatment costs presented in Table E6 are the total costs of PFT dosage via fluid exchange on the 11 circuits in 2017/18 – however, when one takes into account the fact that the PFT treatment by fluid exchange sets the cable up for all future leaks to be located without further substantial PFT dosing costs, the average cost per leak work out to be less than the average cost to locate using the excavate and freeze method.)

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.
A summary of the CBA tables are included in this report.

E7 – LCTs

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
The methodology used to report the data has allowed allocating the LCTs to the relevant Northern Powergrid licence with a good level of accuracy. We assumed that no heat pumps or DG (G83) were connected to the primary network.

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.
<u>Heat pumps</u> The source of data for heat pump installation and capacity is BEIS public reports on Renewable Heat Incentive. By adopting this report, we have made the following adjustments: - We have assumed that the new non-domestic heat pump deployment as a proportion from total deployments is equal across all administrative regions. - We have adopted a regional split based on administrative border rather than DNO licence borders <u>Electric vehicle chargers</u> The source for Electric Vehicle chargers data is the connection notifications that the installers send to Northern Powergrid. No assumptions or estimations were made on this data before reporting the values in the table. <u>DG (G83):</u> The source for DG (G83) data is Ofgem (e-serve). Customers who install small renewable generation are incentivised to declare it to Ofgem through the Feed-In-Tariff scheme. This has resulted in a higher level of accuracy for this data source compared to that held by Northern Powergrid. We have made the following low-risk assumptions whilst using the data source: • "Commissioned date" corresponds to the connection date of the LCT, • "Installed capacity" corresponds to the size of the LCT installed, we use it to filter the G83 from non-G83, • Installations for which supply MPAN information was unavailable (blank cells in column *Supply MPAN No*) were cross-referenced with a list of Northern Powergrid's postcode districts. Where a postcode district corresponded to both Northern Powergrid Yorkshire and Northern Powergrid North East, 50% of the total capacity and 50% of the total installations have been assumed to be in each DNO licence area. This issue arises for installations which do not have a supply meter, and the Feed-In-Tariff report does not include export meter data. The issue has been highlighted to Ofgem.

We have restated 2015/16 and 2016/17 numbers in order to remain true to the database, which is updated every quarter, and after consultation with the team in Ofgem (e-serve) responsible for the report. This has resulted in increase of capacity and volumes and we attribute it to be a lag in the registration by customers for the Feed-In-Tariff.

Changes in estimated size of PVs installed:

	Northeast			Yorkshire		
	Reported in 2017	Reported in 2018	Change, %	Reported in 2017	Reported in 2018	Change, %
2016	36.30	46.10	27.0%	42.00	59.20	40.96%
2017	3.20	4.85	51.5%	6.10	8.87	45.44%

Changes in estimated volumes of PVs installed:

	Northeast			Yorkshire		
	Reported in 2017	Reported in 2018	Change, %	Reported in 2017	Reported in 2018	Change, %
2016	11,787	12,181	3.34%	12,936	13,407	3.64%
2017	1,003	1,260	25.62%	1,887	2,323	23.11%

DG (non G83)

The source for DG (non G83) data is the connection request database held in Northern Powergrid.

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.

Our forecast of LCT uptake in our licence areas, over the RIIO-ED1 period was quantified in our submission back to Ofgem of Table CV103 in 2014.

The rate of LCT uptake is highly sensitive to the Government's stimuli and also depends on the market's ability to find profitable business models.

During the regulatory year 2015-16, a reduction took place on FiT and RHI, and Renewable Obligation (RO) closed for new onshore wind operators. In 2017, the Government announced its plans to ban new petrol and diesel car sales from 2040. As a result, the uptake of LCTs has been slow, although the uptake of electric vehicle chargers has slightly increased in 2017/18.

Our expectation is that DG volumes will stabilise at similar volumes in the short term followed by a pick-up, as markets identify new business models; and that the deployment of EV chargers will be relatively stable unless Government transport and energy policy or new commercial models more strongly support the introduction of charging infrastructure.

Heat pumps

Our LCT growth projection for the 2015-23 period was based on a Low HP forecast scenario. In Yorkshire and the Northeast, the actuals are well below forecast (both in terms of number of installations and input electrical capacity).

Electric vehicle chargers

Our LCT growth projection was again based on Low EV forecast scenario.

Although there has been an increase in chargers installed when compared to 2017 figures, the comparison between actuals versus forecast shows that EV chargers are behind forecast.

Photovoltaic (G83 and non-G83)

Our LCT growth projection was based on the low DECC forecast for HV and EHV, and the medium DECC forecast for LV.

As last year, the actuals are well below forecast level in terms of number of installations, but nearing it in terms of capacity. This confirms the evolution of the market in the last couple of years towards larger sized installations, which is especially acute in Yorkshire. Also, the number of small installations (G83) has dropped significantly year over year, which was unforeseen in the projections. In 2018/19 we expect Government to determine fiscal support for the FIT regime post March 2019 which will have an impact on the generation being connected.