SP Energy Networks 2015–2023 Business Plan

Updated March 2014

Annex

Expenditure Supplementary Annex

SP Energy Networks

March 2014

SP ENERGY NETWORKS

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Expenditure Supplementary Annex

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1. Scope 6

2. Table of linkages 6

3. Introduction 9

4. Expenditure Overview 11
4.1. Total Expenditure 11
4.2. Expenditure Profile 12
4.3. Cost Benefit Analysis (CBA) 13
4.4. Expenditure by licence 14

5. SPM Manweb Company Specific Factors 17

6. Cost Assessment, Efficiency and Benchmarking 21
6.1. Introduction 21
6.2. Cost Assessment Approach 22
6.2.1. Unit costs 22
6.2.2. Indirect Costs 24
6.3. Volumes 26
6.4. Summary 28

7. Load related expenditure 29
7.1. Summary 29
7.2. Objectives 30
7.3. Background 30
7.3.1. Demand growth, including low carbon technologies (LCTs) 30
7.3.2. New Connections Growth 31
7.3.3. Energy Efficiency 32
7.3.4. Triggers for investment 32
7.3.5. Mid Wales Wind Farms 33
7.3.6. SP Manweb network arrangement 33
7.4. Low Carbon Technologies and the TRANSFORM Model 34
7.5. General Reinforcement 35
7.5.1. Load growth 36

7.5.2. Load Index 36
7.5.3. Primary Network Reinforcement 37
7.5.4. Secondary Network Reinforcement 40
7.6. Fault Level Reinforcement 40
7.7. Smart Alternatives to Conventional Reinforcement 41
7.8. Connections 41
7.8.1. Introduction 41
7.8.2. Competition in Connections 42
7.8.3. Expenditure Overview 43
7.8.4. Future Forecasts 44
7.8.5. Market Segments Used in the Forecast 44
7.8.6. Future Connections Activity - Demand 46
7.8.7. Minor Connections (mainly LVSSA, LVSSB, market segments) 46
7.8.8. Future Connections Activity - Distributed Generation 47
7.8.9. Future Connections Activity - Unmetered Connections 49
7.8.10. Expansion of Scope of Contestable Work 49
7.8.11. Market Share Lost to Third Parties 50
7.9. Transmission Connection Points 50

8. Non-Load Related Investment 51
8.1. Building Our Plans 51
8.1.1. Asset Health and Criticality Indices 52
8.1.2. Health Index (HI) 52
8.1.3. Criticality Index (CI) 53
8.1.4. Asset Risk 53
8.1.5. Legal and Safety 54
8.1.6. Stakeholders 55
8.1.7. Deterioration Modelling 55
8.1.8. Selecting Intervention Options 55
8.1.9. Identifying Investment Requirements 56
8.1.10. Forecasting Method for Each Asset Category 57
8.2. Asset Replacement and Refurbishment 58
8.2.1. Overview 58
8.2.2. Asset Replacement and Refurbishment Expenditure Forecast Summary 58
8.2.3. Long Term Strategy 61
8.3. Detail of Asset Replacement and Refurbishment Expenditure 66
8.3.1. Underground Cables Strategy 66
8.3.2. Overhead Lines 79
8.3.3. Switchgear 96
8.3.4. Transformers 119
8.3.5. Protection Refurbishment 130
8.3.6. UG and OHL Pilots 132
8.3.7. Batteries at HV, 33kV and 132kV Substations 134

8.3.8. Civil Works 136
8.3.9. Operational Information Technology and Telecoms 140
8.3.10. BT 21st Century (BT21CN) 144
8.3.11. Black Start 146
8.3.12. Flood Mitigation 148
8.3.13. Critical National Infrastructure 149
8.3.14. Legal & Safety 150
8.3.15 ESQC Regulations 155
8.3.16 Undergrounding in National Parks and AONB 156
8.3.17 Oil Pollution Mitigation 156
8.3.18 Reducing Technical Losses 157
8.3.19 Noise Mitigation Measures 161
8.3.20 Worst Served Customers 162

9 Network Operating Costs 163
9.1 Incident Response 163
9.1.1 Trouble Call 163
9.1.2 Responding to 1 in 20 Year Storms 164
9.1.3 Incident Response Costs 164
9.1.4 Fault Management 164
9.2 Inspection and Maintenance 166
9.2.1 Inspections 167
9.2.2 Maintenance 167
9.3 Vegetation Management 168
9.3.1 Tree cutting for safety clearance (ENATS 43-8) 168
9.3.2 Falling Distance Tree Cutting (ETR132) 169
9.3.3 Other Network Operating Costs 169
9.4 SPM Company Specific Factors 170

10 Closely Associated Indirect Costs 171
10.1 Overview 171
10.2 Closely Associated Indirect Costs 171
10.2.1 Introduction 171
10.2.2 Network Design and Engineering 172
10.2.3 Project Management 173
10.2.4 Engineering Management and Clerical Support 174
10.2.5 System Mapping – Cartographical 175
10.2.6 Control Centre 175
10.2.7 Call Centre 176
10.2.8 Stores 177
10.2.9 Network Policy 178
10.2.10 Operational Training /Workforce Renewal 178

10.2.11 Vehicles and Transport 179

11 Business Support Costs 181
11.1 Introduction 181
11.2 Human Resources and Non-Operational Training 182
11.3 Finance and Regulation 182
11.4 CEO, Group Directors and Corporate Communication 183
11.5 IT and Telecoms 184
11.6 Property 185

12 Non Operational Expenditure 186
12.1 IT and Telecoms 186
12.2 Vehicles 187
12.3 Property 187
12.4 Environmental Compliance 187
12.5 Small Tools and Equipment 188

13 Smart Metering Costs 189

14 Non Activity Based Costs 190

15 Real Price Effects 191

1. Scope

This Annex sets out our RIIO-ED1 expenditure plans across all categories of our costs for both of our licences. We describe how we have developed the plans and how we have worked to ensure that they are as cost efficient as possible.

2. Table of linkages

This annex supports our ED1 Business Plan. For ease of navigation, the following table links this annex to other relevant parts of our plan.

Document	Chapter / Section
Annex C6 – Cost Benefit Analysis - SPEN	4.3
Annex C6 – Operational IT and Telecoms Strategy - SPEN	5
Annex C6 – SP Manweb Company Specific Factors - SPEN	5
Annex C6 – Cost Assessment, Efficiency and Benchmarking - SPEN	6.1
Annex C6 – Cost Assessment, Efficiency and Benchmarking - SPEN	6.2.1
Annex C6 – Non-load related investment (132kV cables, 132kV Overhead line and 132kV substation strategies) - SPEN	6.2.1
Annex C6 – Cost Assessment, Efficiency and Benchmarking - SPEN	6.2.2
Annex C6 – Heat Pump and Energy Efficiency Scenarios – Frontier Economics	7.3.1
Annex C7 – Smart Grid Strategy – Creating a network for the future - SPEN	7.3.1
Annex C6 – Heat Pump and Energy Efficiency Scenarios – Frontier Economics	7.3.3
Annex C6 – SP Manweb Company specific factors - SPEN	7.3.6
Annex C7 – Smart Grid Strategy – Creating a network for the future - SPEN	7.4
Annex C6 – Load Related Investment Strategy - SPEN	7.5
Annex C7 – Smart Grid Strategy – Creating a network for the future – SPEN	7.5.3
Annex C7 – Smart Grid Strategy – Creating a network for the future – SPEN	7.5.4
Annex C7 – RIIO-ED1 Review Project – Smarter Grid Solutions	7.7
Annex C6 – Asset Health and Criticality Approach - SPEN	8.1.3

Annex B3 – Learning from Stakeholders – SPEN	8.1.6
Annex C6 - 132kV Cables Strategy - SPEN	8.3.1
Annex C6 - Rising Mains & Laterals Strategy – SPEN	8.3.1
Annex C6 - 132kV Tower Lines Cost Benefit Analysis CBA reference no 48-SPEN.	8.3.2
Annex C6 – Cost Benefit Analysis, reference no. 50 – SPEN	8.3.2
Annex C6 - 132kV overhead lines Strategy – SPEN	8.3.2
Annex C6 - 33kV and 11kV OHL Strategy - SPEN	8.3.2
Annex C6 - LV OHL and ESQCR Strategy - SPEN	8.3.2
Annex C6 – Cost Benefit Analysis ref no.12 - SPEN.	8.3.2
Annex C6 – Cost Benefit Analysis ref no.50 - SPEN.	8.3.2
Annex C6 – Cost Benefit Analysis ref no.61 - SPEN.	8.3.2
Annex C6 – Cost Benefit Analysis ref no.6 - SPEN.	8.3.2
Annex C6 - Cost benefit Analysis reference no. 11 - SPEN.	8.3.3
Annex C6 - Cost Benefit Analysis reference no. 62-SPEN	8.3.3
Annex C6 - Cost Benefit Analysis reference no. 2-SPEN.	8.3.3
Annex C6 - Cost Benefit Analysis reference nos. 59 and 60 - SPEN.	8.3.3
Annex C6 - Cost Benefit Analysis reference nos. 52, 53 and 54 - SPEN.	8.3.3
Annex C6 - 11kV Plant Strategy - SPEN	8.3.3
Annex C6 - LV Plant Strategy - SPEN	8.3.3
Annex C6 - 132kV Substations Strategy - SPEN	8.3.3
Annex C6 - 33kV Plant Strategy - SPEN	8.3.3
Annex C6 - 11kV Plant Strategy - SPEN	8.3.4
Annex C6 - LV Plant Strategy - SPEN	8.3.4
Annex C6 - 132kV Substations Strategy - SPEN	8.3.4
Annex C6 - 33kV Plant Strategy - SPEN	8.3.4
Annex C6 – Cost Benefit Analysis ref nos.1.1, 1.2, 7 - SPEN.	8.3.4
Annex C6 – Cost Benefit Analysis reference nos. 63, 64.1 and 64.2-SPEN.	8.3.4

Annex C6 – Protective Equipment and Supporting Systems Strategy - SPEN	8.3.5
Annex C6 – Protective Equipment and Supporting Systems Strategy - SPEN	8.3.6
Annex C6 – Cost Benefit Analysis ref no.9 - SPEN.	8.3.6
Annex C6 – Protective Equipment and Supporting Systems Strategy - SPEN	8.3.7
Annex C6 - Civil Strategy and Plans - SPEN	8.3.8
Annex C6 – Cost Benefit Analysis ref nos.51.1, 51.2 - SPEN.	8.3.8
Annex C6 - Operational IT & Telecoms Strategy – SPEN	8.3.9
Annex C6 - Light Current Strategy – SPEN	8.3.9
Annex C6 - BT21CN Mitigation Strategy – SPEN	8.3.10
Annex C6 - Cost Benefit Analysis reference no. 65-SPEN	8.3.10
Annex C6 - Cost benefit Analysis reference no. 3-SPEN	8.3.11
Annex C6 - Legal & Safety Strategy - SPEN	8.3.14
Annex C5 – Black Start Capability – SPEN	8.3.18
Annex C6 – Cost Benefit Analysis ref nos.1.1, 1.2 - SPEN.	8.3.18
Annex C6 – Cost Benefit Analysis ref nos.68.1, 68.2 - SPEN.	8.3.18
Annex C6 – Cost Efficiency, Efficiency and Benchmarking - SPEN	10.2.1
Annex C5 – Social Obligation Strategy – SPEN	10.2.7
Annex C8 – Insurance Strategy – SPEN	11.3
Annex C6 – Non-operational IT and Telecoms Strategy – SPEN	11.5
Annex C6 - Non-operational IT and Telecoms Strategy - SPEN	12.1
Annex C6 – Real Price Effects 2014/15 to 2022/23 – First Economics	15

3. Introduction

In this annex, we set out our RIIO-ED1 expenditure plans across all categories of our costs for both of our licences. We describe how we have developed the plans and how we have worked to ensure that they are as cost efficient as possible.

We believe that this plan represents excellent value for money for our customers. In preparing it, we have looked at every area in which we incur costs in substantial detail, not just those areas where we were aware that we were not amongst the most efficient in our industry. We have identified where we can build on our strengths to deliver our activities even more efficiently in the future and we have tackled the areas where we were weaker than the 'best in class', not shirking from committing to transformational change where we see it is necessary to deliver the scale of improvement we require.

To ensure that what we propose to spend is appropriate and efficient, we:

- *sought the views of our stakeholders, and aligned our investment plan to their priorities.*
- *reviewed Ofgem's benchmarking of costs across all DNOs' July 2013 plans and undertaken extensive additional benchmarking analysis of our own*
- *critically reviewed all aspects of the expenditure plan that we published in July 2013 using expertise from within our own business, industry consultancies and the Iberdrola Group*
- *carried out a substantially expanded programme of cost benefit analysis (CBA) to ensure that we are making the right investments in the right assets at the right time.*

The result of our efforts is a stronger plan that will allow us to meet all of the primary outputs that we set for ourselves back in July 2013 for a total cost of £4740M, representing a saving of £300M when compared to our expenditure forecast presented at that point last year. Excluding changes in costs beyond our control, the revised plan delivers an underlying saving of £450M in the core costs of operating our Businesses.

The expenditure plan is set out in the following sections:

Section	Title	Content
1	Scope	
2	Table of Linkages	
3	Introduction	
4	Expenditure Overview	High level description of our expenditure plan
5	SPM Manweb Company Specific Factors	Description of the company specific cost implications of the SPM urban interconnected network
6	Cost Assessment, Efficiency and Benchmarking	How we have gone about ensuring that our costs are as efficient as possible and how we benchmark against other DNOs and Ofgem's expert assessments
7	Load related expenditure	The cost of reinforcing the network and undertaking diversions
8	Non-load related investment	• *Asset replacement and refurbishment* • *Meeting legal obligations* • *Improving safety, environmental and network performance*
9	Network operating costs	• *Responding to faults and other call-outs* • *Inspection and maintenance* • *Vegetation management* • *Other minor operational costs*
10	Closely associated indirect costs	• *Operating control and call centres* • *Managing projects* • *Stores* • *Operational training* • *Other services that support our work programmes*
11	Business support costs	• *Human resources* • *Finance and regulation* • *CEO office* • *Non-operational training* • *Other corporate costs*
12	Non Operational Expenditure	Investment in vehicles, mobile plant, IT, telecoms and property and other minor investments.
13	Smart Metering Costs	Costs associated with the roll-out of smart meters and getting access to smart meter data
14	Non activity based costs	Costs largely beyond our control including transmission exit charges, business rates and licence fees
13	Real Price Effects	The overall cost impact of differences between the index that is used to update our revenues each year and the movements in commodity and specialist labour costs

4. Expenditure Overview

4.1. Total Expenditure

SP Energy Networks Summarised Ofgem business plan categories, 2012/13 price basis	2010-2015 DPCR5 Total (£m)	2010-2015 DPCR5 Average (£m)	2015-2023 RIIO-ED1 Total (£m)	2015-2023 RIIO-ED1 Average (£m)	% Change
Inspections, maintenance and vegetation management	144.6	28.9	272.5	34.1	18%
Troublecall & Other Network Operating Costs	245.1	49.0	373.0	46.6	-5%
Total network operating costs	389.6	77.9	645.5	80.7	4%
Asset Replacement and Refurbishment (including Civil Works)	535.2	107.0	940.6	117.6	10%
Operational IT and Telecoms	17.1	3.4	51.7	6.5	89%
ESQCR (Low Ground Clearance)	94.8	19.0	109.0	13.6	-28%
BT 21st Century, Environmental, Legal and Safety	46.9	9.4	128.7	16.1	71%
Black Start, Flooding and Critical National Infrastructure	4.5	0.9	14.4	1.8	97%
Rising & Lateral Mains	74.7	14.9	120.1	15.0	0%
AONB and Worst Served Customer initiatives	2.7	0.5	18.0	2.2	322%
Diversions	26.1	5.2	33.9	4.2	-19%
Total non load-related expenditure (including future proofing for low carbon scenarios)	802.0	160.4	1416.4	177.0	10%
Customer driven reinforcements (net of contributions)	28.3	5.7	63.0	7.9	39%
General reinforcement including low carbon technologies	146.1	29.2	295.5	36.9	26%
Total load-related expenditure (including low carbon scenario)	174.4	34.9	358.5	44.8	28%
Indirect Costs	504.4	100.9	577.5	72.2	-28%
Business Support Costs	261.4	52.3	282.7	35.3	-32%
Non-operational capex	45.4	9.1	104.1	13.0	43%
Total engineering and corporate support costs	811.2	162.2	964.3	120.5	-26%
Smart metering enabling works	0.0	0.0	17.4	2.2	
Technology Trials (stand alone funding mechanisms)	0.0	0.0	0.0	0.0	0%
Total Core Costs	2177.3	435.5	3402.1	425.3	-2%
Non activity-based costs & Streetworks Reopener	651.2	130.2	1179.2	147.4	13%
Real price effects	-0.3	-0.1	158.8	19.9	
Non-controllable Costs	650.9	130.2	1338.0	167.2	28%
Total	**2828.2**	**565.6**	**4740.1**	**592.5**	**5%**

As can be seen in the table above:

Our annual average expenditure on a like for like basis across ED1, excluding costs beyond our control (non-activity based costs such as tax and rates, and real price effects) will be 2% less than we are spending in DPCR5.

This reduction, albeit minor, in our core spend is not being made at the expense of outputs, In fact, we are planning to invest more in our key work programmes to produce more deliverables than ever before. We will increase our investment in our non-load work programmes by 10% and load related programmes by 28% over DPCR5 levels. The increases in the volume of deliverables will be even greater than the increase in headline expenditure as we will deliver more due to unit cost reductions and the deployment of innovative interventions which will make the money go further.

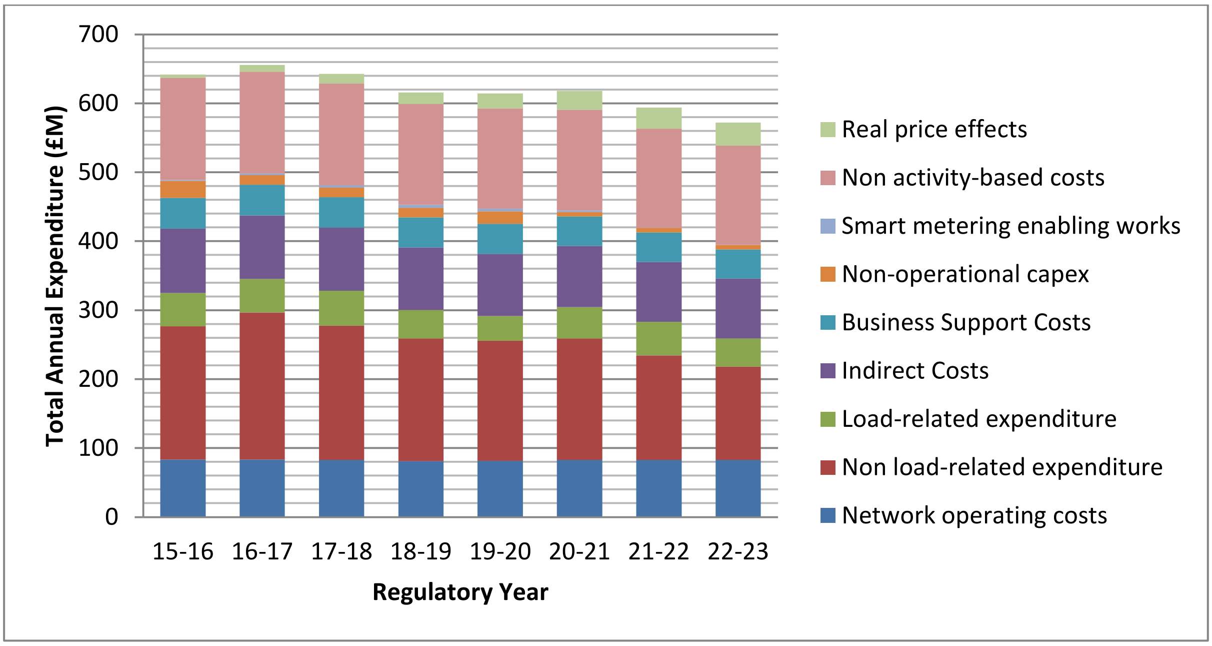
We will fund the increase in investment in deliverables by making significant savings in the costs of operating the non-frontline aspects of our operations. Our plan includes savings of 28% and 32% in our indirect and business support costs respectively.

The work we have done in DPCR5 to reduce our Trouble call costs, which we intend to build on further in ED1, will deliver a cost saving of 5% compared to the DPCR5 average, whilst also meeting the challenge of faster restoration times.

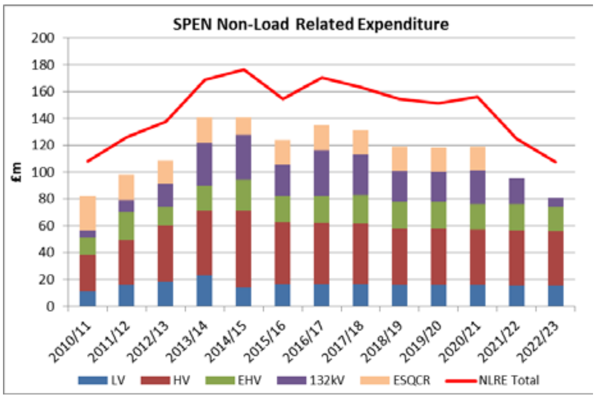
Our aim is to put more of the money we get from our customers directly into maintaining and improving the asset base and into the services that our customers and our stakeholders value.

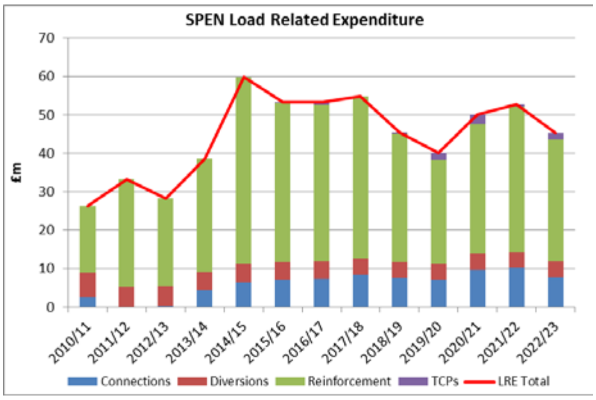
4.2. Expenditure Profile

The phasing of our total ED1 expenditure is shown in the chart below.



This profile results from the combination of our cumulative 1% per annum efficiency target and a number of timing effects. These timing effects are predominantly related to our investment programmes. The following two charts show the profile of our load and non-load investment for both licences over the combined DPCR5 and ED1 periods:





As can be seen in these graphs, we have increased our investment levels through DPCR5 to the point that our underlying delivery capacity is in place to make a smooth transition into the ED1 expenditure programme.

Our non-load investment profiles are shaped by:

- *ESQCR investment to remove all overhead line low ground and proximity clearances before the end of 2020.*
- *In the case of SPM, the phasing of expenditure to deliver our 132kV outputs – these projects are typically large, multi-year investments and in the latter years of ED1, costs drop off as equipment procurement and construction for ED1 outputs are largely completed.*

- *BT21 mitigation expenditure, as this work must be completed before the end of 2018. This effect is most pronounced for SPM, which has a substantially larger programme to deliver in this area.*

Load related investment shows the following timing effects:

- *There is a significant increase in expenditure in the final year of DPCR5 in SPM as we complete reinforcement projects at Nantwich, St Asaph, Maentwrog and Llangollen. In addition, the main procurement and construction activities are now underway on 2 large schemes, Legacy – Oswestry Reinforcement and the new 132kV substation at Fiddler's Ferry. Both of these projects were materially delayed as a result of consenting difficulties.*

- *We also have a number of large projects which will be initiated early in the ED1 period, following completion of our DPCR5 schemes. These include key reinforcements at Crewe, Whitchurch, Lostock and Carrington.*

- *The increase in expenditure towards the end of ED1 in SPM results from a combination of the implementation of some 132kV schemes which we have forecast for delivery in the latter half of ED1 to allow for consenting timescales, increasing LCT uptake towards the end of the price control period and our decision to phase a number of projects that have more load growth uncertainty in the final years.*

4.3. Cost Benefit Analysis (CBA)

We have used CBA extensively in the production of this plan, building upon the proven process we adopted for our July 2013 plan, to both demonstrate our programmes represent value for money for our customers and to properly inform the delivery choices we have made. We have applied CBA to programmes accounting for 70% of our total load and non-load related investment. We have concentrated our work in areas where the technique could contribute usefully to our decision making, as there are elements of investment, examples being meeting statutory obligations, customer driven reinforcement investment and undertaking diversions, where CBA at plan level is not informative.

Cambridge Economic Policy Associates were commissioned by Ofgem to review the usage of CBA within DNOs' July 2013 plans. In their report, they wrote:

SP's analysis presents the most convincing discussion of alternative options for consideration within their CBAs. They consider two or more options against the baseline in sixteen of their twenty-two CBAs (compared to WPD which considers only one option in 118 out of 150 CBAs). Most importantly our more detailed assessment of their models suggests that they have generally considered a sensible range of options, taking the care to assess relevant strategies / approaches for each of their CBAs.

They also pointed out that:

The main positive of their work is that it is very clear and generally easy to follow. The inclusion of a detailed CBA annex makes it easy to understand why they are including a CBA and the link to the business plan; most importantly it also gives the sense that the CBAs have been used as a tool to help with the overall decision making – overall SP's presentation of the CBAs analysis is the clearest of all the Groups.

Our approach to cost benefit analysis is proportionate, transparent and compliant with current HM Treasury Green Book guidelines (July 2011 update). The programmes and schemes we chose for cost benefit analysis naturally fall into the following categories:

- *Major replacement and refurbishment schemes and programmes across the asset base.*
- *Load related reinforcement schemes taking into consideration potential smart grid solutions*
- *Environmental schemes, OHL undergrounding, loss reduction, tree cutting*
- *Operational IT and Telecoms (SCADA) projects including BT21CN*
- *Network future proofing using the Transform Model.*
- *Civil and structural remediation work.*
- *Smart Grid technology - justifying our Smart Grid strategy*
- *Smart Meter - justifying our Smart Meter roll-out strategy*
- *Losses reduction - justifying our Loss reduction strategy*

In determining what to include in our cost benefit analysis portfolio we considered the following;

- *Whether discrete technology or delivery options were available, consistent with our licence obligations.*
- *Our RIIO-ED1 strategic objectives to reduce carbon emissions and provide sustainable value for money for customers.*
- *Specific Stakeholder input, where it was available.*
- *Providing a justification for our strategies as set out above for losses, smart grids and smart meters.*
- *Ensuring broad coverage of our entire investment portfolio.*

We have been totally transparent in our analysis, clearly setting out the basis for our cost and benefit inputs and providing evidential references where these are available. Whenever possible, multiple options were considered, some were rejected early in the process for particular engineering or deliverability reasons.

As a result we are confident that the programmes and projects set out in the business plan are both affordable and deliverable and will represent sustaining value for money for our customers over the ED1 plan period.

Our cost benefit analysis process

Our objective when developing the CBA process for ED1 was to ensure consistency and transparency, objectivity, accuracy and quality.

Consistency and transparency were achieved by ensuring the project / scheme owners understood the process of developing the models and had access to key data such as asset deterioration, performance trends and other fixed data sources. Furthermore, it was important we demonstrated how the cost, volume and benefit inputs were derived by clearly setting out any underlying assumptions and including a relatively high level of detail on the make-up of all the input parameters.

Objectivity was achieved by holding the project / scheme owners to account for production of the models, provision of the input cost / benefit data and selection of the preferred investment option.

Accuracy and quality was ensured in three ways; first, the models were reviewed by senior engineering management to confirm they were consistent with the business plan submission. Second, the models were reviewed for accuracy by the regulatory and finance teams in order to ensure we had total confidence in both the modelling and the investment decisions that flowed from it. Finally, a totally transparent and comprehensive overall approach to the identification of appropriate options at both the long-list and shortlist stage ensured that the output from the modelling was both robust and of high quality.

The outcome from our cost benefit analysis has been fed into our investment plans and throughout this chapter we have indicated where CBA has been used in developing our plans. The accompanying annex to this document Annex C6 — Cost Benefit Analysis – SPEN provides a summary of each of the cost benefit analyses we have performed in building our plans.

4.4. Expenditure by licence

The tables on the following pages set out a summary of our expenditure for each licence. Further explanation is provided in the remaining sections of this chapter, supported as appropriate by further detail in related annexes.

SPD – Expenditure Plan Summary

SP Distribution	2010-2015	2010-2015	2015-2023	2015-2023	% Change
Summarised Ofgem business plan categories, 2012/13 price basis	DPCR5 Total (£m)	DPCR5 Average (£m)	RIIO-ED1 Total (£m)	RIIO-ED1 Average (£m)	
Inspections, maintenance and vegetation management	46.8	9.4	114.6	14.3	53%
Troublecall & Other Network Operating Costs	139.8	28.0	197.0	24.6	-12%
Total network operating costs	186.6	37.3	311.6	38.9	4%
Asset Replacement and Refurbishment (including Civil Works)	213.3	42.7	341.0	42.6	0%
Operational IT and Telecoms	6.9	1.4	19.7	2.5	77%
ESQCR (Low Ground Clearance)	33.4	6.7	47.9	6.0	-10%
BT 21st Century, Environmental, Legal and Safety	25.0	5.0	48.2	6.0	21%
Black Start, Flooding and Critical National Infrastructure	1.6	0.3	3.3	0.4	28%
Rising & Lateral Mains	53.7	10.7	81.1	10.1	-6%
AONB and Worst Served Customer initiatives	0.1	0.0	8.3	1.0	8155%
Diversions	11.0	2.2	11.0	1.4	-37%
Total non load-related expenditure (including future proofing for low carbon scenarios)	344.9	69.0	560.5	70.1	2%
Customer driven reinforcements (net of contributions)	4.6	0.9	4.8	0.6	-35%
General reinforcement including low carbon technologies	66.9	13.4	140.4	17.6	31%
Total load-related expenditure (including low carbon scenario)	71.5	14.3	145.2	18.2	27%
Indirect Costs	246.5	49.3	273.3	34.2	-31%
Business Support Costs	124.8	25.0	152.2	19.0	-24%
Non-operational capex	23.4	4.7	53.4	6.7	43%
Total engineering and corporate support costs	394.7	78.9	478.9	59.9	-24%
Smart metering enabling works	0.0	0.0	8.7	1.1	
Technology Trials (stand alone funding mechanisms)		0.0		0.0	
Total Core Costs	997.7	199.5	1505.0	188.1	-6%
Non activity-based costs & Streetworks Reopener	376.2	75.2	718.2	89.8	19%
Real price effects	-0.2	0.0	68.5	8.6	
Non-controllable Costs	376.0	75.2	786.7	98.3	31%
Total	**1373.7**	**274.7**	**2291.6**	**286.5**	**4%**

SPM – Expenditure Plan Summary

SP Manweb Summarised Ofgem business plan categories, 2012/13 price basis	2010-2015 DPCR5 Total (£m)	2010-2015 DPCR5 Average (£m)	2015-2023 RIIO-ED1 Total (£m)	2015-2023 RIIO-ED1 Average (£m)	% Change
Inspections, maintenance and vegetation management	97.8	19.6	158.0	19.7	1%
Troublecall & Other Network Operating Costs	105.3	21.1	176.0	22.0	5%
Total network operating costs	203.0	40.6	334.0	41.7	3%
Asset Replacement and Refurbishment (including Civil Works)	321.9	64.4	599.6	74.9	16%
Operational IT and Telecoms	10.2	2.0	32.0	4.0	97%
ESQCR (Low Ground Clearance)	61.3	12.3	61.1	7.6	-38%
BT 21st Century, Environmental, Legal and Safety	22.0	4.4	80.6	10.1	129%
Black Start, Flooding and Critical National Infrastructure	2.9	0.6	11.0	1.4	136%
Rising & Lateral Mains	21.0	4.2	39.0	4.9	16%
AONB and Worst Served Customer initiatives	2.6	0.5	9.7	1.2	133%
Diversions	15.2	3.0	22.8	2.9	-6%
Total non load-related expenditure (including future proofing for low carbon scenarios)	457.1	91.4	855.8	107.0	17%
Customer driven reinforcements (net of contributions)	23.7	4.7	58.2	7.3	54%
General reinforcement including low carbon technologies	79.2	15.8	155.0	19.4	22%
Total load-related expenditure (including low carbon scenario)	102.9	20.6	213.3	26.7	30%
Indirect Costs	258.0	51.6	304.2	38.0	-26%
Business Support Costs	136.6	27.3	130.5	16.3	-40%
Non-operational capex	22.0	4.4	50.7	6.3	44%
Total engineering and corporate support costs	416.6	83.3	485.3	60.7	-27%
Smart metering enabling works	0.0	0.0	8.7	1.1	
Technology Trials (stand alone funding mechanisms)	0.0			0.0	
Total Core Costs	1179.6	235.9	1897.2	237.1	1%
Non activity-based costs & Streetworks Reopener	275.0	55.0	461.0	57.6	5%
Real price effects	-0.1	0.0	90.3	11.3	
Non-controllable Costs	274.9	55.0	551.3	68.9	25%
Total	**1454.4**	**290.9**	**2448.5**	**306.1**	**5%**

5. SPM Manweb Company Specific Factors

In section B of our Plan, we summarised the unique challenges associated with our Manweb interconnected network. The design of this network is significantly different to that of the networks operated by the other DNOs, including our own SPD network in Scotland. The SPM network delivers better levels of system performance compared to conventional network designs and is generally very flexible in accommodating new customer requirements. However, the downside to this is that it is more expensive to run. Our approach is to minimise the additional cost and maintain the benefits to customers of having this type of network.

We keep the SPM network design under review and for extensions to the network we consider whether we should extend the interconnected design approach or revert to a traditional, radial design if it is technically practicable and does not compromise the high levels of service to existing customers. However, there are a number of practical reasons that would make it very difficult to fully convert the SPM interconnected network to a radial network. In keeping with our own analysis, independent reviews undertaken in the past concluded that large scale conversion is not cost effective.

Our existing network has many substations containing a single transformer connected to cables that are smaller than the standard size that would be required for a radial network. Converting the network to a radial design would require additional space to accommodate a second transformer at over 1000 of our 132kV and 33kV substations. Often these sites are land locked meaning that new sites would have to be found. In addition, we would have to excavate thousands of streets to install larger underground cables to deal with the increased power flows on the radial circuits. This would be expensive, would result in significant disruption to the public and would take many years to complete.

Through the competition in connections process we must offer the lowest cost of connection. To satisfy this requirement we review the existing network design and technical parameters and, where possible, even within a fully interconnected network, offer radial connections. Sometimes, however, developers seeking a large connection will opt to fund an interconnected solution as it can be developed in stages. Although the interconnected network solution could turn out to be more expensive, it may match the developer's appetite for risk in a situation where the future growth of the development (such as an industrial estate or office/technology park) is uncertain.

Incremental network growth due to new connections or increased demand can generally be accommodated within the interconnected network at lower cost compared to a radial network. This is particularly important as we look forward to the increase in the deployment of low carbon technologies by customers. However, should the SPM interconnected network reach its limit (saturation) then this will trigger a major network reinforcement scheme.

The point at which end-of-life assets are being replaced presents another opportunity to consider options to convert the network to a radial design. Each project has to be evaluated individually based on local factors and often the capital cost of conversion is similar to that of continuing with the interconnected design. However, the benefit to customers will be delivered over the lifetime of the asset through lower operating costs.

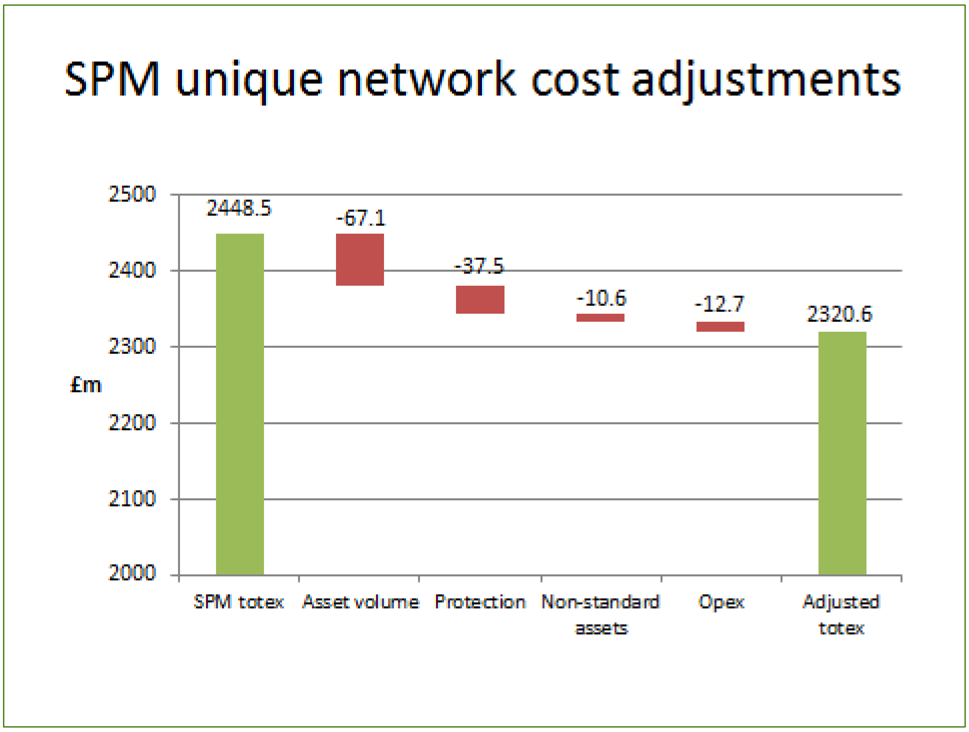
The examples outlined above detail our approach to the challenge we face in retaining the benefits of the SPM interconnected network while keeping costs to customers as low as possible. In summary the SPM interconnected network has distinct advantages, including less customer interruptions and its ability to more readily accommodate the uptake of low carbon technologies by customers. The main disadvantages are (a) it is more expensive to build and operate and (b) when network capacity is used up the resulting reinforcement is more extensive than for a radial network. There is no case for converting the SP Manweb network to a fully radial network.

In developing our ED1 expenditure plan, we commissioned two further independent reviews of the SPM interconnected design, undertaken by Parsons Brinckerhoff Power and Mott McDonald, and these studies, along with an associated economic analysis undertaken by NERA Economic Consulting confirm our approach and verify our assessment of the additional costs involved in operating the network for the ED1 period.

We have calculated that our costs in ED1 will be £128m higher as a direct consequence of the unique elements of the SPM network. These additional costs will be incurred across a range of activities, covering both capital expenditure and operating costs.

Compared to a conventional network serving the same customer base the SPM network :

- *contains a higher volume of the standard assets such as transformers and switchgear;*
- *has significantly more protection equipment;*
- *contains some non-standard assets that have a higher cost compared to the equivalent elsewhere;*
- *incurs higher operating costs because of the higher number of assets and greater complexity.*



These are described in turn, with examples of the key incremental costs:

Higher volume of standard assets

The SPM network is designed in a mesh layout rather than radial. As the name implies a mesh design has more nodes and more interconnections between these nodes for any given area. These nodes and interconnections equate to assets such as transformers, switchgear and cables, all of which need to be replaced when they reach the end of their lives. The higher volume of transformers, switchgear and associated civil assets means that we will incur costs of £67.1m during RIIO-ED1 that would not be incurred in a radial network.

Protection equipment

All networks have protection equipment to protect the assets in the event of a fault. Different forms of protection exist, ranging from simple fuses to "distance protection" to "unit protection". Unit protection is the most sophisticated form of protection as it requires equipment at all entry or exist points of the protected section of network plus communication links between these. The extent of interconnection in the SPM network means that SPM is much more reliant on unit protection. A large proportion of our additional protection cost is for communication links and, in particular, the costs of securing alternatives to those currently provided by BT as these will not provide the service we require beyond 2018. Our expenditure on protection in SPM during RIIO-ED1 will be £37.6m higher as a result of the unique protection requirements of the SPM network. For further details see Annex C6 - Operational IT & Telecoms Strategy - SPEN.

Non-standard assets

A secondary substation in the SPM interconnected network is configured in a different way in order to facilitate interconnection and the associated protection. Non-standard components include:

- *a circuit breaker on the low voltage side of the transformer,*
- *an 11kV ring main unit (RMU) which always requires a circuit breaker (not a fused switch) and contains additional auxiliary switches,*
- *current transformers, pilot wires (communications links) and batteries for the protection, and*
- *a brick/block housing to ensure the correct operating environment for the ancillary equipment.*

Our RIIO-ED1 investment programme for SPM contains £10.6m of costs relating to these non-standard assets.

Operating costs

The higher volume of switchgear, transformers and protection equipment in the SPM network results in higher maintenance costs. Repair and maintenance of substation civils is also substantially higher, partly because of the higher volume of substations but also because of the different construction standard mentioned above. In addition, the communication links between our protection equipment sometimes develop faults or are damaged by third parties. The cost of these repairs would not be incurred in a conventional network. Finally, faults on the SPM network are considerably harder to locate and, therefore, fault repair costs are higher. Overall we have calculated that the incremental operating costs for SPM in the RIIO-ED1 period is £12.7m.

Our calculations of the incremental costs for the SPM network have been carried out at a detailed level. The full detail is provided in Annex C6 – SP Manweb Company Specific Factors – SPEN, along with the reports of the independent reviews we commissioned as part of our ED1 preparations.

The breakdown of the costs is summarised below:

SPM incremental costs for RIIO-ED1 period (£m)

Network level	Capex	Opex	Total
33kV	74.4	8.7	83.1
11kV	18.6	2.1	20.7
LV		1.8	1.8
Load related	22.1		22.1
Total	115.1	12.6	127.8

In the remaining sections of this chapter, we have identified the additional costs that relate to the unique Manweb network. These are summarised in the following table:

SPM Company Specific Factors					
Category	CV table	Row No.	Normal Track SPM RF submission		SPM Regional Cost Factors - Rationale
33kV Non Load Investment					
Primary transformer asset replacement	CV3	83	£	5.65	Based on ED1 plan to replace 89 x 7.5MVA transformers in ED1 @ £181k unit cost, typical radial system could satisfy same MVA capacity with 37 x 12/24MVA transformers @ £265k each. = £6.3m with efficiency =£5.56m
Ring Main Unit asset replacement	CV3	69			Based on ED1 plan to replace 33 x 33kV Ring Main Units in ED1, with no SPEM approved 33kV RMU's the cost differential is reported under indoor 33kV CB's category as the replacement option
Outdoor ground mounted circuit breaker asset replacement	CV3	71	£	7.79	Based on ED1 plan to replace 99 outdoor 33kV CB's at Primary sites, not be required on Traditional Industry Networks. Costs for 2 CB's at Grid sites excluded from SPM RF case
Indoor ground mounted circuit breaker asset replacement	CV3	70	£	11.76	Based on ED1 plan to replace 99 outdoor 33kV CB's as an alternative to RMU's and 6 CB's at Primary sites, that would not be required on Traditional Industry Networks. Costs 45 indoor CB's at Grid sites excluded from SPM RF case
Unit protection pilot wires 'hardex' overhead and underground cables	CV3	103 & 104	£	3.23	Based on ED1 plan to replace 70km of poorly performing protection underground pilots and 25 end of life 'Hardex' pilot cables on the overhead network. Cost differential based on SPD costs and volumes as a proxy for Traditional Industry pilot expenditure.
BT 21 centaury communications channel replacement	CV10	6	£	23.22	Based on ED1 plan and BT requirement to replace copper communication circuits by end of 2018. SPM have greater dependency on these circuits for our unit protection systems. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
Protection modernisation	CV5	37	£	4.38	Based on ED1 plan to modernise remote end protection inline with Primary substation switchgear replacement programme. Cost differential based on removing these assets from plan. Costs at Grid sites and Primary Transformer excluded from SPM RF case.
Black Start resilience associated with Primary substations	CV11	74	£	0.91	Based on ED1 plan to make qualifying 33kv primary substations resilient for 72hrs. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
Operational IT associated with RTU replacement	CV105	6	£	6.37	Based on ED1 plan to modernise ageing RTU infrastructure at 33kv primary substations. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
Operational IT associated with Ethernet communications for switching & monitoring	CV106	7	£	4.75	Based on ED1 plan to modernise ageing communications platform to improve data retrieval and monitoring at 33kv primary substations. Cost differential based SPD on volumes and unit cost as proxy for Traditional Industry design requirement
Substation civil works	CV6	16	£	6.34	Based on ED1 plan to secure and modernise our 33kV Substation assets. SPM have greater volumes than Traditional industry standard including unit requirement for RMU enclosures. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
sub tot			**£**	**74.40**	
HV Non Load (11 & 6.6kV) Investment					
X- type Ring Main Unit asset replacement	CV3	38	£	7.33	Based on ED1 plan to replace 1706* HV X type Ring Main Units in ED1, these have discrete SPM components. Cost differential based on delivering same volume at SPM Y type RMU unit cost.
X- type secondary transformer asset replaceme	CV3	48	£	0.17	Based on ED1 plan to replace 281 X-type HV GM secondary transformers, these have discrete SPM components and costs. Cost differential based on delivering same volume at SPM Y-type HV GM transformer unit cost with efficiency.
Secondary substation battery replacement	CV3	51	£	1.01	Based on ED1 plan to continue to replace X-type secondary substation batteries on a 6 year rolling programme, these are discrete SPM components. Cost differential based on SPD volumes and unit cost for HV substation battery replacement as proxy for Traditional Industry design requirement
Secondary substation civils	CV6	,7,8,9,(14 &1	£	10.13	Based on ED1 plan to secure and modernise our HV Substation assets. SPM have greater volumes than Traditional industry standard including unit requirement for RMU enclosures. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
sub tot			**£**	**18.64**	
33kV I&M					
Substation maintenance, inc pfm	CV13	44, 45 & 46	£	2.23	Based on discharging SPM substation maintenance policy and unit costs for 33kV assets including those associated with SPM discrete 33kV unit protection systems, inc post fault. Cost differential based on removing the SPM discrete Unit protected network elements from plan as not required on Traditional Industry Networks
Underground pilot cable faults	CV15b	17	£	3.36	
3rd Party rented communication & protection pilots	CV13	71	£	2.17	Based on ED1 plan to continue to rent BT communications services pre and post BT21CN transition. Costs assume rental cost will remain constant. Cost differential based on Removing 33KV unit protection costs from budget.132kV and Grid site costs excluded from SPM RF case.
Translay unit protection battery replacement pro	CV13	49	£	0.02	Based on ED1 plan to replace batteries associated with Translay unit protection intertrip batteries on 8 year roiling programme, SPM discrete asset on unit protection schemes. Cost differential based removing requirement from programme as not required on Traditional Industry Networks
Underground cable fault repair	CV15a	30	£	0.97	Based on additional costs are associated with the length of cable being repaired in an interconnected system being 20-75% longer than the equivalent radial system. It is necessary to replace a longer length because the higher fault level leads to more cable being damaged around the site of a fault. Cost differential based on SPM volumes at SPD unit cost as a proxy for traditional network design
sub tot			**£**	**8.74**	
HV I&M (11 & 6.6kV)					
X- type Secondary substation maintenance, inc	CV13	28, 29 & 30	£	2.10	Based on discharging SPM substation maintenance policy and unit costs for HV assets including those associated with SPM discrete HV unit protection systems, inc post fault. Cost differential based on removing SPM discrete X-Type discrete costs and volumes and applying SPM non X-Type unit cost to remaining assets.
sub tot			**£**	**2.10**	
Load Related Investment - All voltages					
Network Reinforcement through voltage up-ratin	CV101	10	£	0.48	Based on ED1 plan to capitalise on Latent network capacity by up rating 4* 6.6kv networks to 11kV. Cost differential based on delivering same volume at SPM Y-type HV GM transformer unit cost with efficiency.
Network Reinforcement schemes at 132-EHV and EHV-HV	CV101	10 &14	£	20.03	Based on ED1 plan for network reinforcement to release >450MVA of network capacity. Cost differential based on applying PB Power Confirmed normalising factor based on all costs inherent and associated with mesh network expansion.
33kV switchgear at Primary substation fault level mitigation	CV101	116	£	1.60	Based on ED1 Plan to mitigate fault level issues associated with 4 primary substations containing 33kV RMU's. Cost differential based on removing this work from programme.
sub tot			**£**	**22.11**	
LV Networks					
Underground cable fault repair	CV15a	17	**£**	**1.83**	Based on additional requirement for extra fault finding excavation of LV open circuit faults which are difficult to locate on interconnected circuits. Cost differential based on SPM volumes at SPD unit cost as a proxy for traditional network design
		£m	**£**	**127.82**	

6. Cost Assessment, Efficiency and Benchmarking

6.1. Introduction

We are acutely aware of the financial pressures on our customers, particularly in the current economic climate. Consequently we have sought to make our plan amongst the most efficient in the industry in order to mitigate the impact on our customers' bills.

Ofgems activity based analysis accounted for a 75% weighting in the determination of allowed Totex for the Fast Track process. NERA has indicated that the selection of this weighting appears to be arbitrary. In addition in the analysis identified that SPENs business plan was "inefficient" by over £1Bn. A reduction in this has been applied by Ofgem to move the gap to £696M as shown above. We are unable to ascertain as to the rationale for this reduction.

In addition Ofgem applied a reduction in allowed costs due to regional labour adjustments. We consider that this is not appropriate for two reasons:

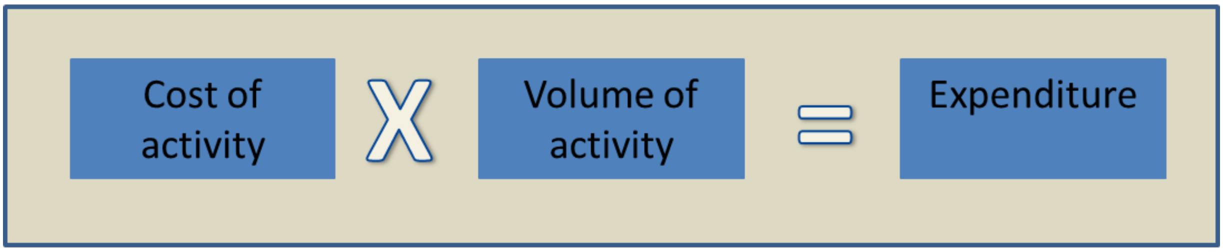
- *Our unit costs are based on actual costs incurred*
- *The analysis used to determine higher costs in London and the South East also suggests that an uplift be applied in Scotland.*

A full review of this is included in Annex C6 Cost Assessment, Efficiency and Benchmarkng - SPEN.

From the analysis on an activity basis we have identified the areas where we needed to refocus our efforts in our cost and volume assessments or to provide / direct Ofgem to additional information to support our investment requirements. These are as follows:

- *Asset replacement and refurbishment expenditure*
- *BT21CN*
- *Technical Loses and Environment*
- *I&M*
- *Trouble call/ONIS*
- *Load related expenditure*
- *Closely Associated Indirect costs*

We have completed a comprehensive review of all of our expenditure.



We believe that our July 2013 submission was an efficient Business Plan. However, we have acted on the feedback from Ofgem and carried out a comprehensive review of all areas of our plan including:

- *Volumes of activity*
- *Costs of activities – where we reviewed unit costs of individual activities or undertook econometric or statistical analyses to assess costs of activity groups. (e.g. indirect or back office costs)*

This has resulted in a revised Business Plan that is more efficient whilst allowing us to:

- *Manage our ageing network to maintain public, staff and contractor safety*
- *Improve customer service*
- *Reduce the number and length of power cuts (including during major storms)*
- *Prepare the network for low carbon technology.*
- *Delivery a high quality outcome for all of SPEN's stakeholders*

6.2. Cost Assessment Approach

The two main building blocks of our cost base are:

- *Unit Costs - the cost of carrying out work (e.g. the cost of replacing a transformer).*
- *Indirect Costs (e.g. the cost of supporting and managing our work programmes).*

We set our costs throughout our July 2013 Business Plan to be amongst the most efficient in the industry. Our updated plan has this same goal taking account of the latest information.

6.2.1. Unit costs

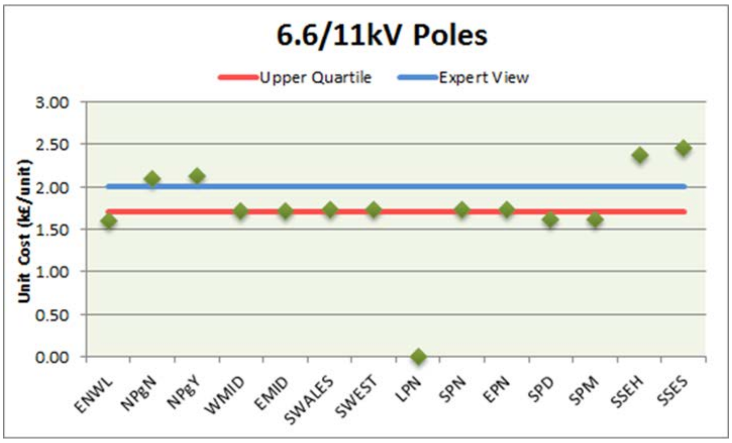
Ofgem stated in their assessment of our July 2013 business plan:

SPD is efficient on asset replacement and refurbishment unit costs across the majority of assets. SPMW is relatively high on unit costs across the majority of assets.

This reflects the considerable effort we spent in our July Business Plan submission where we reviewed:

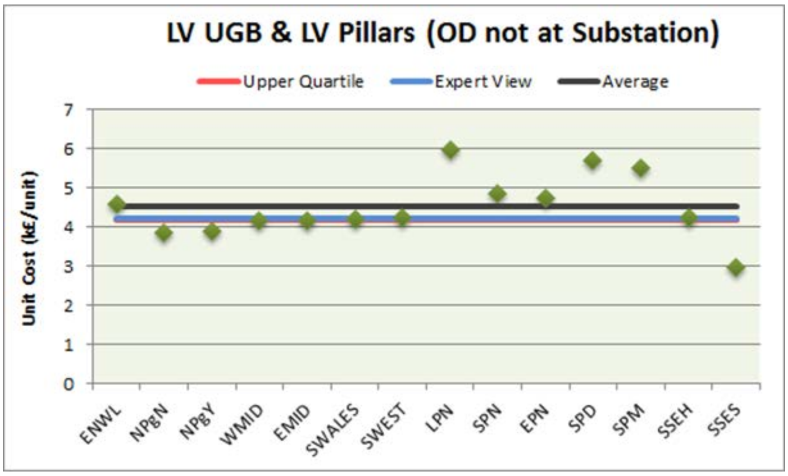
- *Every activity we undertake on our networks, including cost of installation, cost of refurbishment and cost of restoration.*
- *The costs associated with the supply of plant and equipment.*
- *The contracts associated with the supply of installation or service contractors.*
- *Our own internal costs.*
- *The time we spend on our activities.*
- *Full compliance with the Regulatory Instructions and Guidance (RIGs) provided by Ofgem.*
- *Best practice across our two network areas so that the same unit costs were applied across both licences for the majority of assets (unless there was a clear technical and economic argument for higher costs)*

We have now taken this further following the feedback from Ofgem and have compared our unit costs against the unit cost benchmarks provided by Ofgem's Expert (DNV KEMA) and those of the fast tracked DNO, WPD. The following chart is an example of this analysis:



The chart shows that our unit cost for HV Pole replacement is £1.6K – the frontier cost for UK DNOs. The Ofgem expert view was set at £2K and WPD's unit cost is £1.72K. Through this level of detailed assessment we have ensured that our unit costs, where comparable to the other DNOs, are amongst the most efficient in the industry for the activities we undertake.

There are a number of areas where our unit costs would appear greater than Upper Quartile or the expert view. The chart below sets out an example of this, for LV pillars:

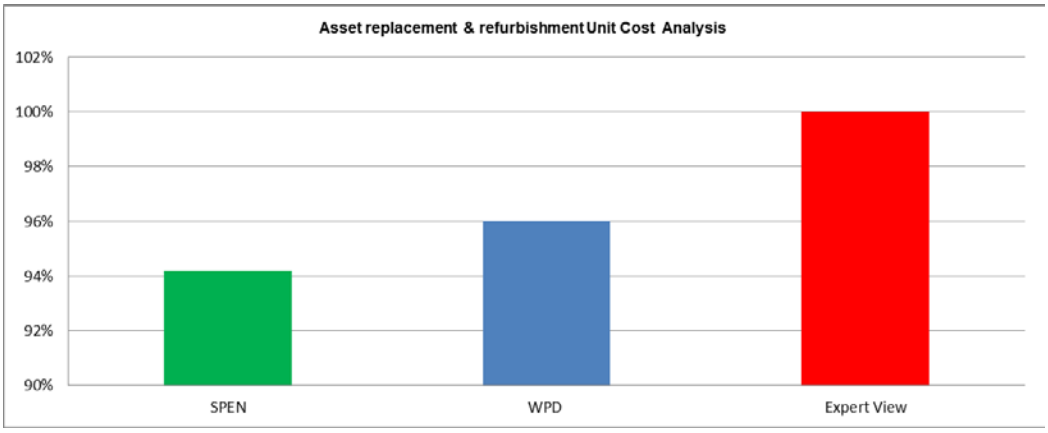


There are 8 different variations of this asset type (2 way to 8 way pillar or link box) each with a different cost. Our unit cost reflects the average cost of replacing these. If a DNO replaces a greater volume of smaller pillars, their average unit cost would be lower. We have ensured that our unit cost for all activities is efficient and reflects current competitively tendered rates.

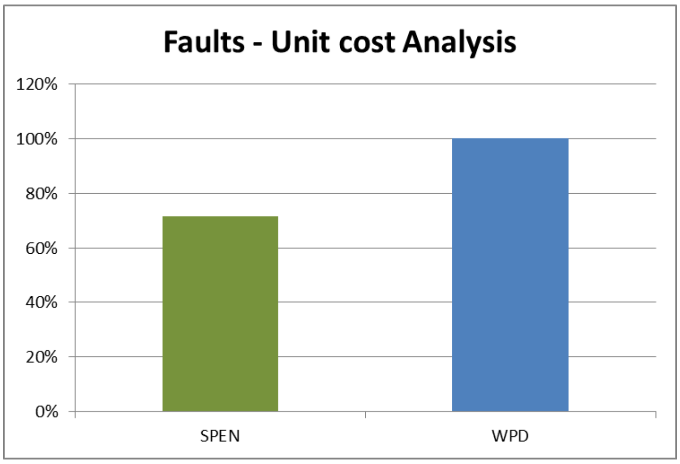
A full review of all the unit costs is presented in our Annex C6 - Cost Assessment, Efficiency and Benchmarking - SPEN.

It should be noted that there are areas where it is difficult to use the unit cost approach to assess cost efficiency. If innovative solutions require expenditure with a unit cost that is greater than Upper Quartile or Ofgem's expert view, they could be disallowed. We have ensured that such instances are supported by Cost Benefit Analysis.

In the following categories, the charts below demonstrate how we perform in terms of unit cost. These charts exclude unit costs associated with our SPM 132kV programmes for which a separate annex is included in Annex C6.



We have also compared our fault costs with WPD and the result is presented in the following chart:



This may reflect the practice WPD employs of undertaking an average of 30 metres of cable replacement on each low voltage fault compared with an industry average of 5-6 metres as presented by WPD at the cost assessment working group on 13th February 2014.

In summary the unit costs in our July 2013 Business Plan were amongst the most efficient in the industry They are even more efficient in our revised Business Plan.

6.2.2. Indirect Costs

Our indirect costs include Project Management, Design, HR, Finance, Engineering Management, Clerical Support, Control and Call centres, training, vehicles and transport. They are known as Closely Associated Indirect and Business Support Costs. These are the back office support for our front line activities and are covered in detail in sections 10 and 11 of this annex. The assessment of these costs is normally undertaken using statistical or econometric analysis.

We know that our current level of indirect costs is considerably higher than those of the frontier or Upper Quartile DNOs.

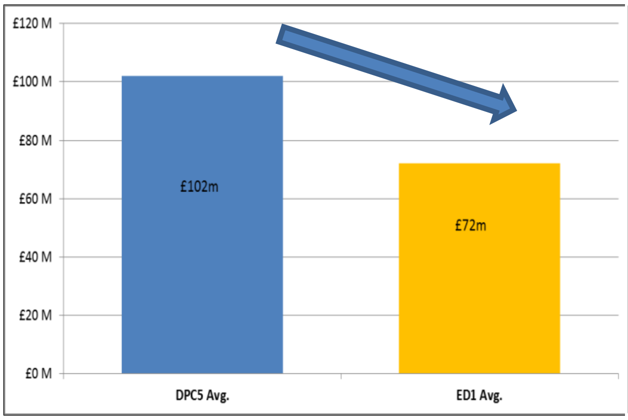
As a consequence, for our Fast Track Submission we:

- *Ensured that all our costs are categorised in accordance with the RIGs guidance.*
- *Undertook a comprehensive review of all of our costs in each area of our support activities.*
- *Ensured that the costs are recorded correctly and have been allocated accordingly.*
- *Set a challenge for our business that we should only ask customers to fund efficient levels of cost in RIIO-ED1, with our shareholders carrying the risk of achieving this ambitious goal.*

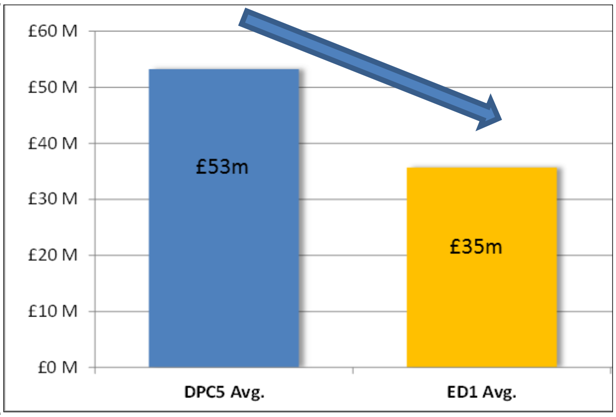
We then set our total indirect costs at a level that is amongst the most efficient in the industry. This requires a reduction on our indirect costs of 30% across our two licences.

To deliver the scale of this challenge, we have established a business implementation team and have started to reduce our costs to meet the targets set through this cost assessment process. The scale of this challenge which is shown graphically below and we describe the initiatives we are taking to deliver on this in sections 10 and 11 of this annex and more fully in Chapter 7, Business Readiness.

SPEN average annual CAI costs



SPEN average annual BS costs



In their response to our July 2013 submission, Ofgem stated:

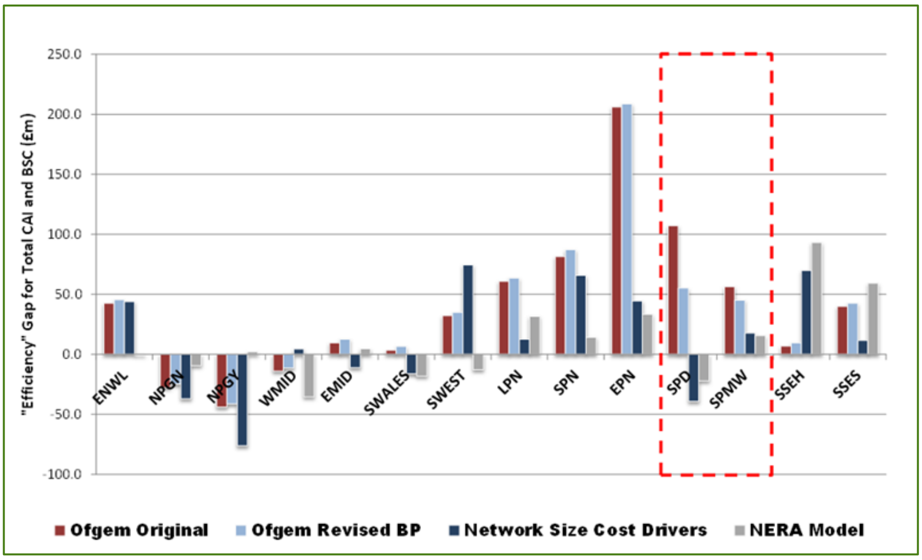
For closely associated indirects, SPEN's expenditure appears less justifiable than other DNOs and both its DNOs benchmark poorly, with SPD benchmarked as the least efficient company for the regressed CAI activities.

The benchmarking was undertaken by Ofgem using weighted MEAV as a dominant factor is assessing allowances. We have worked closely with Ofgem and have retained the services of NERA Economic Consulting to review the assessment process and to recommend alternative models to allow the assessment of indirect costs. (a copy of NERA's reports can be found in our Annex C6 - Cost Assessment, Efficiency and Benchmarking - SPEN).

Through this work, NERA has produced an alternative set of models to assess on a regression basis that:

- *Have a higher explanatory value*
- *Leave less cost variations attributed to inefficiency*
- *Pass the series of statistical tests*

The model for CAI and Business Support Costs makes use of employee numbers and CSV as drivers. It produces an assessment of our indirect costs as depicted below:



This model shows:

- *Ofgem's Fast Track analysis of SPEN indirect costs had an efficiency gap of £165M*
- *With our proposed revisions to the Business Plan, this gap reduces to £100M using the same Ofgem model.*
- *Using the NERA proposed model, SPEN indirect costs are assessed as being amongst the most efficient in the industry, completely removing the gap and indicating an outperformance of £10M relative to our peers.*

However, NERA conclude that similar models can provide greatly differing results and that these models alone should not be used to reduce DNOs allowances without first considering why there is a perceived efficiency gap.

We have removed an additional £80M from our CAI costs - predominantly through changes to our Workforce Renewal Programmes and through a further efficiency stretch across our Closely Associated Indirect and Business Support costs. We have reviewed in detail each area of our CAI and BS costs in Annex C6 - Cost Assessment, Efficiency and Benchmarking - SPEN.

In summary, the indirect costs in our July 2013 Business Plan were amongst the most efficient in the industry. They are even more efficient in our revised Business Plan

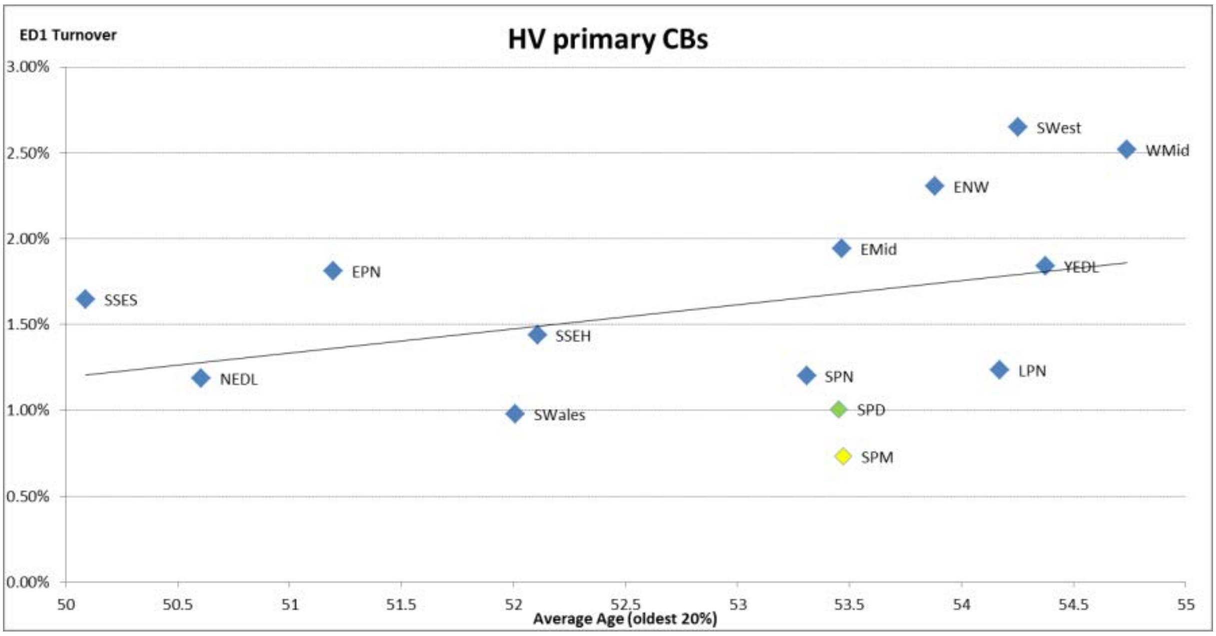
6.3. Volumes

Ofgem stated the following in their assessment of our July 2013 business plan:

SPD's replacement and refurbishment volumes are high compared to our modelling. SPMW's asset replacement volumes are extremely high compared to our modelling and its refurbishment volumes are also high.

A considerable amount of Ofgem's modelling for the fast track process was based on industry average, median volumes or implied asset life which deemed any increase over historic asset replacement run rates for the 3 years 2010-2013 to be inefficient. It did not consider differences in DNOs' plans arising from differences in asset health or actual age profiles. This modelling indicated a volume gap of £397M value between our July 2013 estimate of the required workload and Ofgem's analysis for asset replacement, refurbishment and civils alone. In assessing our volumes, we believe that there is a requirement to justify the need for investment. To do so we have prepared detailed engineering justifications based on site inspections, fault history and condition reports. Every substation has been surveyed and 83% of our 603,000 poles inspected to ensure that the need for investment is based on physical evidence.

We also use the relative age of our equipment compared to that for other DNOs to ascertain if our volumes of activity reflect industry averages. The diagram shown below illustrates this principle. The Y axis shows the expenditure proposed for ED1 on primary circuit breaker replacement expressed as a percentage of the total replacement value for each DNO, the X axis being the average age of the oldest 20% of primary circuit breakers. From this, we can see that our circuit breakers are amongst the oldest in the UK. We would expect that the expenditure would be higher than the other DNOs if age is taken as a proxy for condition and the need for replacement. Using our site condition data, however, we do not need to undertake the expected levels of investment that DNOs of a similar age are undertaking. We have carried out this level of robust checking for every area of our expenditure.



Volume Changes

From our benchmarking, we have reviewed the engineering cases and assumed, where possible, a higher level of risk whilst not compromising our ability to deliver our primary outputs.

There are a number of areas where we cannot reduce volumes, as we would be faced with an increase in risk to intolerable levels:

- *Where the level of risk to staff or the public is too high.*
- *Where there is a legislative or government requirement – e.g. ESQCR or Black Start.*
- *Where there is a definitive cessation of service provision e.g. BT21CN.*
- *Where stakeholders have asked us to do more, e.g. storm resilience and poorly served customers*

The vast majority of our July 2013 planned volumes remain in our updated plan, but we have identified volume reductions in the following areas:

- *Pole replacement and refurbishment*
- *Overhead line conductor*
- *Civils*
- *LV Boards*
- *11kV cable*

In addition, we have rescheduled our SCADA programmes to spread the expenditure into ED2, creating a smoother investment profile over a longer period. We have also made a change to the methodology of replacing 132kV switchgear at our Rainhill substation in Merseyside, which delivers a significant cost reduction in expenditure at that site in ED1.

We have also reviewed our reinforcement activity levels and have taken account of additional information on LCT uptake rates which has resulted in reductions in our load related programmes

6.4. Summary

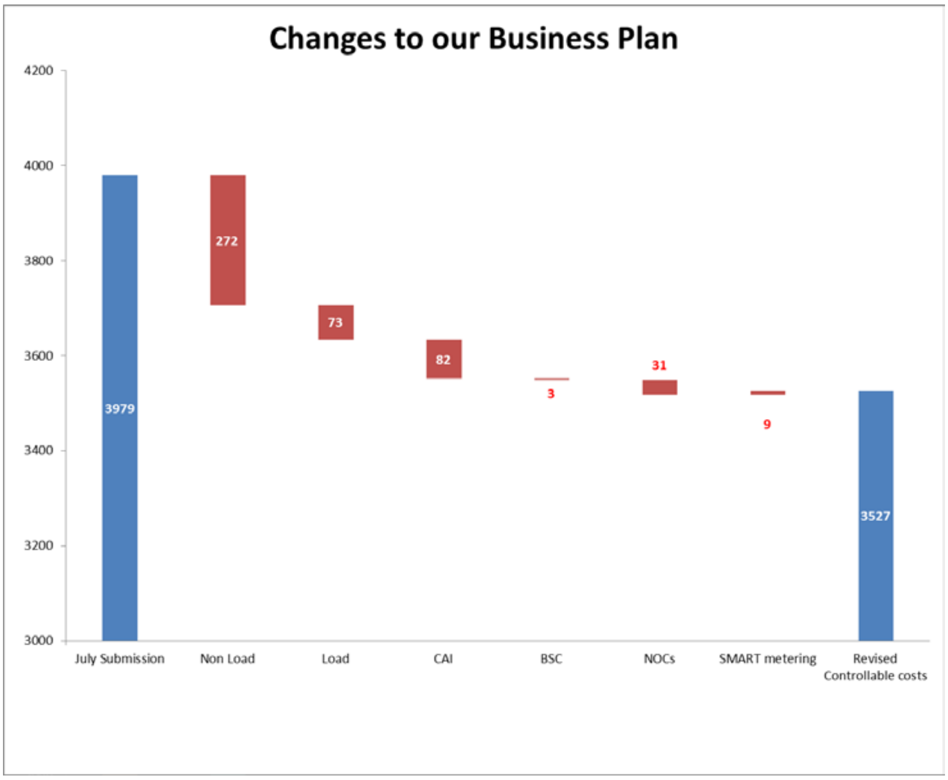
When assessed more comprehensively than the Fast Track timetables allowed, much of our July 2013 plan can be demonstrated to be more efficient than the fast track DNO, WPD. However, we have taken into account the feedback from Ofgem's assessment of our July 2013 business plan. In a number of areas, we have accepted an increase in risk and in doing so, made reductions in our load related and non-load related volumes. In many more areas, we will point Ofgem to engineering and econometric evidence backed by cost benefit analysis to justify the need for our investments and the efficiency of our costs.

Our volumes are now those required to ensure we have a strong stewardship of our assets and world class safety credentials.

We have further reduced our unit costs in areas where we were not amongst the most efficient and further reduced our indirect costs.

We are confident that all of the costs in our July 2013 Business Plan were amongst the most efficient in the industry. They are even more efficient in our revised Business Plan

The net effect of our work since receiving the feedback on our July plan is that we have reduced our controllable costs by £450M from that previously submitted. The waterfall chart below shows the attribution of this reduction to the main cost categories:



We have a business plan where our costs are demonstrably more efficient than that of the Fast Track DNO, WPD.

This review of our investment plan through the use of engineering assessment, cost assessment and econometric modelling with industry leading efficiency as a guiding principle has ensured that we can operate our networks in a safe and effective manner whilst minimising the cost to our customers.

7. Load related expenditure

7.1. Summary

During RIIO-ED1 we expect to invest £358.5m on Load Related Expenditure (LRE). LRE arises from customers' changing usage or demands on our networks. Our planned LRE for the RIIO-ED1 period is summarised below:

Load Related Expenditure (£m)							
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD	General reinforcement	10.3	13.3	29%	51.5	106.4
	Fault Level reinforcement	3.1	3.3	6%	15.4	26.2
	Connections driven reinforcement (DUoS funded)	0.9	0.6	-35%	4.6	4.8
	Transmission Connection Points	0.0	1.0	-	0.0	7.8
	Total	**14.3**	**18.2**	**27%**	**71.6**	**145.2**
SPM	General reinforcement	12.8	16.5	29%	64.0	132.2
	Fault Level reinforcement	3.0	2.9	-6%	15.2	22.9
	Connections driven reinforcement (DUoS funded)	4.7	7.3	54%	23.7	58.2
	Transmission Connection Points	0.0	0.0	-	0.0	0.0
	Total	**20.6**	**26.7**	**30%**	**102.9**	**213.3**
SPEN		**34.9**	**44.8**	**28%**	**174.5**	**358.5**

The above expenditure is supported by 38 separate cost benefit analyses. These cover a cross section of the projects, in particular those with innovative solutions.

Load Related Expenditure (LRE) is necessary to ensure our networks have sufficient capacity in the long-term, continue to operate safely and comply with relevant technical performance standards. Our LRE plan has been developed to meet the needs of all existing and future customer groups.

During the RIIO-ED1 period, we will make targeted investments in network expansion and reinforcement to accommodate the needs of customers against a background of increasing peak demand and energy consumption. This will avoid long-term shortfalls in network capacity. It is important that we understand how our networks are loaded, how much spare capacity exists and that we are able to accurately forecast requirements into the future. A feature of LRE is that we need to be alert to load growth trends at a local level as customer requirements vary considerably across our network areas.

The main components of our LRE plan are described below:

- ***General reinforcement*** *covers the investment required to accommodate general demand growth increases from existing customers. We split our forecast into primary (132kV and 33kV) reinforcement and secondary (11kV and LV) reinforcement. General reinforcement typically involves the upgrading of equipment such as transformers, switchgear, cables and overhead lines to higher capacities.*

- ***Fault level reinforcement*** *is required to keep the network safe. Assets must be able to carry and interrupt the high electrical currents that flow when faults occur on our networks. Sometimes, as a result of changing loads, the ratings of certain assets are exceeded and upgrades are required to ensure the safety of the public and our staff.*

- ***Connections driven reinforcement*** *is sometimes required as a result of a new customer connecting to our network. In many situations the connecting customer funds the reinforcement in full. However, there are circumstances where some of the costs are shared with the wider customer base and funded through use of system charges. There are industry rules in place which govern these sharing arrangements.*

In the sections that follow we explain the background assumptions behind our load related expenditure forecast, the process of developing our plans, the key components of the plans and the deployment of innovation to reduce costs.

7.2. Objectives

The key objective for our load related expenditure is to meet the future requirements of customers. We must do this with a number of other factors in mind:

Affordability

We will find ways to avoid or reduce investment levels where it is economic to do so and does not cause unacceptable levels of risk on our network. We engage in innovation to develop new approaches that can help reduce the required investment. Our load related expenditure plans for RIIO-ED1 have been reduced by £40m through the deployment of innovative solutions.

Compliance

We must comply with our licence conditions and relevant legislation. Our load related expenditure takes account of the voltage requirements specified in the Electricity Supply Quality and Continuity Regulations (ESQCR). We also design our networks to provide sufficient network capacity and system redundancy to comply with Engineering Recommendation P2/6 regarding Security of Supply. In certain circumstances we seek a temporary exemption from this requirement, e.g. where we expect that further customer driven changes will resolve the non-compliance without our intervention. In general, however, our objective is to act to resolve any p2/6 non-compliance.

Network risk

In general terms, the more heavily loaded a network is, the greater the risk that it will be unable to meet the demands placed upon it. A key objective for us is to find an acceptable balance between risk and cost. In the following sections we highlight that we have been loading our assets more heavily than other DNOs which has been made more visible by the adoption of standardised definitions for Load Indices. Consequently, one of our objectives is to bring the SPD and SPM networks more in line with other DNOs. We achieve this in part during RIIO-ED1 but some further investment in RII-ED2 will be required.

7.3. Background

Our plans are underpinned by a number of key assumptions:

7.3.1. Demand growth, including low carbon technologies (LCTs)

We have to accommodate the peak demands that customers require from our networks. These peak demands often occur for a short period and are not well correlated with customers' overall energy consumption. During the economic downturn we observed the number of units (kWh) distributed falling in some years but the peak demands on the network did not change in the same way. Indeed, some parts of our network experienced increasing demands during this period. This means that economic growth is not always a good indicator of the future demands that we will have to accommodate.

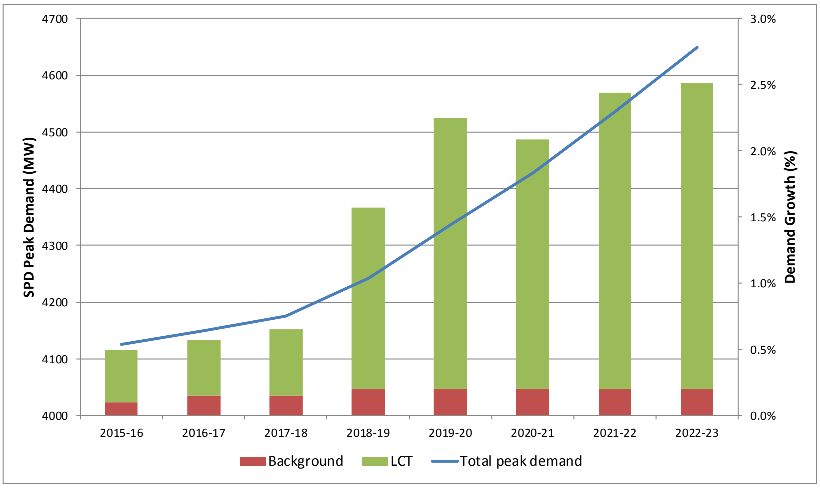
During RIIO-ED1 we expect to see a continuation of modest background demand growth throughout the period. More significantly, we anticipate that the main driver of demand growth, particularly during the latter half of the RIIO-ED1 period, will be customer uptake of Low Carbon Technologies (LCT). We have used the industry standard TRANSFORM model, developed by the Smart Grid Forum, to translate forecasts of LCT uptake into projections of expenditure.

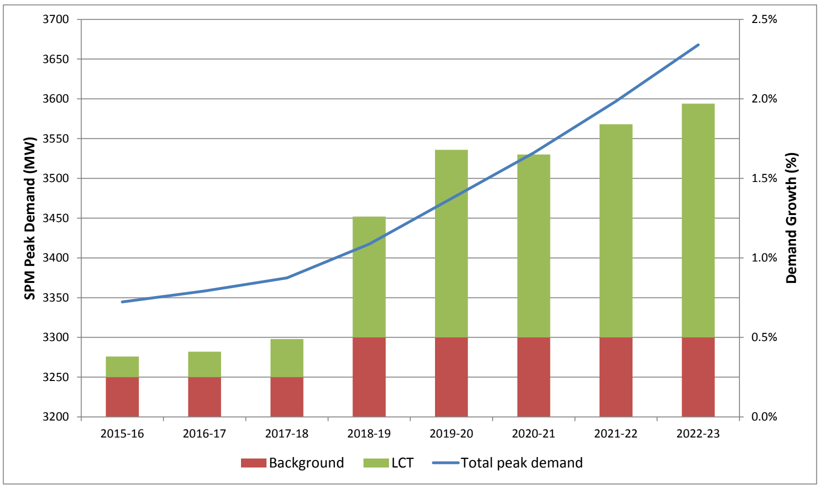
We based our LCT analysis on Department of Energy & Climate Change (DECC) scenarios, each designed to achieve the Fourth Carbon Budget. Our "best view" of LCT uptake is broadly comparable with DECC's "low" uptake. This represents a change from our July 2013 business plan which adopted a "low to medium" uptake forecast. Our revised forecast is supported by an independent assessment by Frontier Economics (Annex C6 – Heat Pump and Energy Efficiency Scenarios – Frontier Economics). Our LCT modelling approach is described in detail in Annex C7 - Smart Grid Strategy – Creating a network for the future - SPEN.

The resulting demand growth assumptions are summarised in and illustrated in the table and charts below.

These have been used to model our network reinforcement requirements for the RIIO-ED1 period. The primary reason for the slight differences between the two areas is that of the LCT uptake in that the SPD network is anticipated to acquire more heat pump installations than the SPM network.

		2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Ave
SPD	Background	0.10%	0.15%	0.15%	0.20%	0.20%	0.20%	0.20%	0.20%	0.18%
	LCT	0.40%	0.42%	0.50%	1.37%	2.05%	1.89%	2.24%	2.31%	1.39%
	Total	**0.50%**	**0.57%**	**0.65%**	**1.57%**	**2.25%**	**2.09%**	**2.44%**	**2.51%**	**1.57%**
SPM	Background	0.25%	0.25%	0.25%	0.50%	0.50%	0.50%	0.50%	0.50%	0.41%
	LCT	0.13%	0.16%	0.24%	0.76%	1.18%	1.15%	1.34%	1.47%	0.80%
	Total	**0.38%**	**0.41%**	**0.49%**	**1.26%**	**1.68%**	**1.65%**	**1.84%**	**1.97%**	**1.21%**





7.3.2. New Connections Growth

SP Energy Networks provides comprehensive connection services to customers for a wide range of projects. We also facilitate competition in the provision of connections by Independent Connection Providers (ICPs) or Independent Distribution Network Operators (IDNOs).

Our connections costs are split into three categories. Assets installed exclusively for a particular customer are regarded as “sole use” assets and are funded directly by the connecting customer. Where there are requirements to increase the capacity of existing shared infrastructure to facilitate a new connection, the associated costs are apportioned between the connecting customer (customer driven reinforcement) and the electricity distribution company (DUoS funded reinforcement).

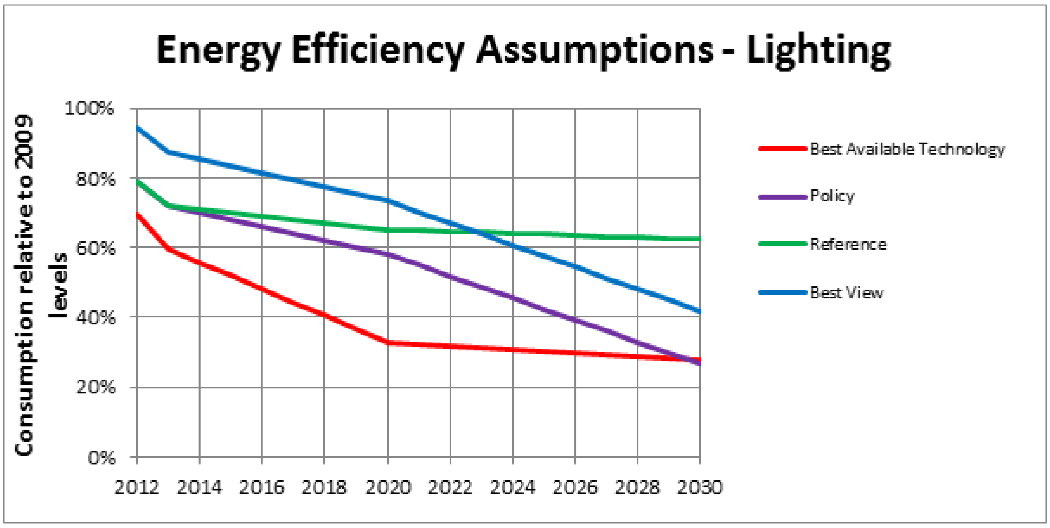
DUoS funded reinforcement costs are built into our price control settlement. Based on our forecasts of connections activity we anticipate that DUoS funded reinforcement costs will amount to 12.3% of our total connections costs during RIIO-ED1. Section 7.8 provides a detailed description of all of our forecast connection activity, covering the DUoS funded and customer funded activities.

Our forecast of total market connections activity is informed primarily by market research and stakeholder engagement with the major players in the development markets we serve (housebuilders, Industrial & Commercial consultants and generation developers). We apply our own view of market share based on our experience of operating in the various sectors.

Our network areas have experienced significant growth in distributed generation during DPCR5. We are forecasting that the development of onshore wind farms will continue throughout the RIIO-ED1 period. We have experienced an increase in the number of generation connection quotes issued and accepted over the last 18 months.

7.3.3. Energy Efficiency

We recognise that energy efficiency improvements will have an impact on the future energy use of our customers. We commissioned Frontier Economics to carry out an independent review of the energy efficiency gains contained within the TRANSFORM Model. The original data was based on an extensive study carried out by DEFRA, as part of their “Market Transformation Programme”, in 2009. This resulted in four different energy efficiency options; flat, reference, policy (the default option) and best available technology. An example relating to lighting energy efficiency is shown below.



Our review found that actual energy efficiency gains tend to lag behind policy targets. Therefore, we adjusted the starting point for energy efficiency improvements in the TRANSFORM model. Our best view as indicated above is now based on a moderated view of the DECC “policy” assumption. This replaces the “reference” assumption, which was used in our original business plan submission. Further information on our energy efficiency assessment can be found in Annex C6 – Heat Pump and Energy Efficiency Scenarios- Frontier Economics.

7.3.4. Triggers for investment

The threshold for triggering load-related network reinforcement is important in determining our general reinforcement expenditure forecast. Some network assets have an in-built capability to be “overloaded” for short durations and through careful management it is possible to use this to avoid or defer reinforcement expenditure. However, this can increase overall network risk.

Over recent years the industry has developed a standard measurement and reporting methodology for the loading of primary network assets. This enables valid comparisons of the loading of different networks. The Load Index (LI) is based on a comparison of the maximum loading of an asset relative to its rating. The duration of the maximum loading condition is also taken into account.

It has emerged though the process of standardising the LI methodology with Ofgem that our networks often operate at higher levels of asset utilisation (with less capacity headroom) than for other DNO networks. We have progressed our load related investment in DPCR5 in line with the original settlement, however, during RIIO-ED1 we will undertake further reinforcement work to bring us in more line with other DNOs. This change was strongly supported by our stakeholders to future-proof our networks and manage risk.

Over the course of ED1 we will also be working with the wider DNO community to review the current security of supply standard, Engineering Recommendation P2/6. This standard was developed a number of years ago and does not reflect the changing nature of the loading on the network such as the increasing contribution of distributed generation, nor the new technology available such as demand side response. This is a significant exercise and will also be influenced by the outcome of the smart Grid Forum activity, in particular Work Stream 7. Our plan is built on the current P2/6 requirements but we will accommodate the revised standard when it is available.

7.3.5. Mid Wales Wind Farms

As a result of the amount of interest of wind farms seeking a connection in Mid Wales, we have taken a strategic approach to engagement with the large number of parties involved including National Grid, wind farm developers and local residents.

The Mid Wales Wind Farm development consists of eight contracted parties with a total of 630.6MW of export capacity and a total scheme CAPEX of approximately £60m. SPM have a Bilateral Construction Agreement with National Grid (NG) to establish a new 400/132kV substation (Mid Wales Hub), with the proposed boundary between SPM and NG being the 132kV side of the proposed Hub substation.

To connect the Wind farms to the Mid Wales Hub it is proposed for SPM to establish four new 132kV circuits. The project is predominantly customer funded with the costs apportioned between the eight developers on a capacity basis.

There are ongoing discussions in relation to potential ownership boundary changes that have been initiated by NG and the results of these discussions may increase the scope and cost of the SPM works. Any changes to the project such as a developer terminating their agreement may result in the additional charges being redistributed between the remaining developers. A significant change in the design or a change to the SPM Charging Methodology could result in further elements of the connections being subject to the apportionment rules and therefore DUoS funded.

Interest in future generation connections continues in the Mid Wales area. The proposed infrastructure will form an economic and efficient foundation on which to develop future generation connections for Mid Wales.

7.3.6. SP Manweb network arrangement

The distribution network built and operated by SPM and its predecessors over the past sixty years is fundamentally different from other DNOs. Most distribution networks are organised radially, but the SPM network is mainly designed and operated meshed at all voltage levels. Although more expensive to build and operate than radial systems, meshed networks offer better reliability and are more adaptable in response to changing load patterns.

Our load related investment plans contain additional costs of £22.11m related to the unique SP Manweb network as follows:

SPM Regional Factors				
Category	CV table	Row No.	Normal Track SPM RF submission	SPM Regional Cost Factors - Rational
Load Related Investment - All voltages				
Network Reinforcement through voltage up-rating	CV101	10	£ 0.48	Based on ED1 plan to capitalise on Latent network capacity by up rating 4* 6.6kv networks to 11kV. Cost differential based on delivering same volume at SPM Y-type HV GM transformer unit cost with efficiency.
Network Reinforcement schemes at 132-EHV and EHV-HV	CV101	10 &14	£ 20.03	Based on ED1 plan for network reinforcement to release >450MVA of network capacity. Cost differential based on applying PB Power Confirmed normalising factor based on all costs inherent and associated with mesh network expansion.
33kV switchgear at Primary substation fault level mitigation	CV101	116	£ 1.60	Based on ED1 Plan to mitigate fault level issues associated with 4 primary substations containing 33kV RMU's. Cost differential based on removing this work from programme.
sub tot			**£ 22.11**	

More information relating to the SPM network arrangement can be found in Annex C6 – SP Manweb Company Specific Factors – SPEN. This includes two independent consultant reports outlining the key differences associated with developing and operating the SPM network.

Network operators with traditional radial networks are assessing how the application of interconnection accommodates future LCT demand through Low Carbon Networks Fund projects. These projects have hypothesised that interconnection will provide network benefits for accommodating future LCT demand. Successful outcomes from these project's trials could lead to increased use of the interconnected network configuration already used in the SPM network.

7.4. Low Carbon Technologies and the TRANSFORM Model

Using the DECC scenarios to inform LCT adoption rates, we have forecast annual increases in electricity demand and consumption for the SPD and SPM networks until 2030. In general, we expect peak demands to increase and load profiles to become flatter. These developments will require a range of network interventions to maintain compliance with relevant standards and meet customer needs.

In this revised business plan, our load growth assumptions have been reviewed and stakeholder feedback has been used to refine our projections accordingly. For RIIO-ED1, our approach has been to enhance our LRE forecasting methodology by superimposing incremental demand growth from customer LCT adoption onto our background growth assumptions.

We have used the TRANSFORM[1] model to quantify the incremental investment requirements arising from LCT technologies, primarily connected to our low voltage networks. TRANSFORM is a techno-economic model used to estimate the impact of low carbon technologies on GB distribution networks. The model contains a cost-benefit tool to compare Smart Grid and conventional network reinforcement options for particular network reinforcement requirements. Model outputs can be produced for various LCT scenarios and include indicative reinforcement solutions with expenditure estimates.

Our LRE forecast has been developed through consideration of DECC scenarios. From these scenarios we have developed a stakeholder tested 'Best View' which has been localised and applied to the SPD & SPM networks. The main variables in DECC's scenarios are adoption rates for efficient heating systems and low-carbon vehicles combined with different levels of building insulation.

The revisions to our 'Best View' scenario were influenced by stakeholders placing more emphasis on electric heating over electric transport as the primary mechanism for reducing greenhouse gas emissions.

Our previous submission was based on a low/medium uptake of LCTs and we have now moderated our LCT forecasts. We are now forecasting a lower uptake of solar Photo-Voltaic panels and electric vehicles during RIIO-ED1 & RIIO-ED2. We have revised or forecasts for heat pump adoption to be slightly higher than DECC's

1 The Smart Grid Forum was established by DECC & Ofgem to support the transition to a secure, safe, low carbon, affordable energy system in the UK. The TRANSFORM model was developed by EA Technology for Workstream 3 of the Smart Grid Forum under the remit of Developing Networks for Low Carbon.

low case for RIIO-ED1 period, rising to low/medium during RIIO-ED2. For energy efficiency, we are forecasting improvement rates similar to Government policy, to be realised later in the period which reflects recent experience. Further information regarding LCT forecast is provided in Annex C7 – Smart Grid Strategy – Creating a network for the future - SPEN.

TRANSFORM outputs for each DECC scenario were compared with our "Best View" and a summary of incremental expenditure requirements, mainly impacting our low voltage networks, is provided in the following table. Our Best View now aligns more closely with the DECC Scenario 4 low case.

SPEN (£M)	DECC1	DECC2	DECC3	DECC4	Best View
ED1	£ 132	£ 137	£ 167	£ 13	£ 24
ED2	£ 583	£ 533	£ 635	£ 32	£ 163
2050	£ 2,114	£ 2,152	£ 2,324	£ 539	£ 952

This modelling also indicates an increasing need to deploy smart grid technologies in parallel with conventional network reinforcements. Whilst the bulk of network investment for LCTs will occur in the RIIO-ED2 period, substantial challenges will emerge during RIIO-ED1 and it will be necessary to develop Smart Grid capabilities in advance.

7.5. General Reinforcement

General Reinforcement Expenditure (£m)							
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD	Primary reinforcement	5.8	7.8	34%	29.1	62.6
	Secondary reinforcement	4.5	5.5	22%	22.4	43.8
	Total	**10.3**	**13.3**	**29%**	**51.5**	**106.4**
SPM	Primary reinforcement	10.4	13.1	25%	52.2	104.5
	Secondary reinforcement	2.4	3.5	46%	11.8	27.7
	Total	**12.8**	**16.5**	**29%**	**64.0**	**132.2**
SPEN		**23.1**	**29.8**	**29%**	**115.5**	**238.6**

Ensuring that we provide sufficient capacity to customers is a key objective. Our approach is described in detail in Annex C6 - Load Related Investment Strategy - SPEN.

To forecast our future investments we carry out a detailed assessment of:

- *Existing network capacity and loadings*
- *Intelligence received from stakeholder engagement on local developments*
- *Predicted load growth*
- *Planned asset renewal work (which may provide additional capacity, or give the opportunity to consider this at the time of renewal)*

The results are considered at the level of individual assets to assess whether or not interventions are required. Where it is economic to do so we adopt innovative solutions as an alternative to traditional reinforcement (see section 7.7).

We have in place an integrated energy investment planning process with Local Authorities to improve our understanding of regional development strategies. This approach entails information sharing regarding the current and future energy needs of particular areas including local development initiatives, strategic investment areas and sustainable energy plans.

We have been very active in our engagement with stakeholders in our major cities (Glasgow, Liverpool and Edinburgh) to ensure our planned network developments are well aligned with future requirements.

7.5.1. Load growth

Our analysis, supported by industry and stakeholder input, provides an estimate of load growth across the SPD and SPM networks. This indicates a modest background load growth onto which we add our forecast of LCT uptake provided via the TRANSFORM model. Load forecasts at individual sites are also informed by information on local developments.

		2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	Ave
SPD	Background	0.10%	0.15%	0.15%	0.20%	0.20%	0.20%	0.20%	0.20%	0.18%
	LCT	0.40%	0.42%	0.50%	1.37%	2.05%	1.89%	2.24%	2.31%	1.39%
	Total	**0.50%**	**0.57%**	**0.65%**	**1.57%**	**2.25%**	**2.09%**	**2.44%**	**2.51%**	**1.57%**
SPM	Background	0.25%	0.25%	0.25%	0.50%	0.50%	0.50%	0.50%	0.50%	0.41%
	LCT	0.13%	0.16%	0.24%	0.76%	1.18%	1.15%	1.34%	1.47%	0.80%
	Total	**0.38%**	**0.41%**	**0.49%**	**1.26%**	**1.68%**	**1.65%**	**1.84%**	**1.97%**	**1.21%**

As we progress through the ED1 period, we will annually re-assess the load predictions and revise the TRANSFORM model with up to date information. This will enable us to track actual LCT uptake and load growth against the predicted values. By regular review of the data and implications we will better manage any scenarios with significantly greater or significant less LCT uptake and therefore be able to flex the implementation programme to match the revised profile. In this way, investment will be optimised and customer expectations realised.

7.5.2. Load Index

The Load Index provides a measure of how heavily loaded network assets are. It is a simple measure based on the substation maximum demand during the year and is structured as follows:

Load Index (LI) Banding	Loading Percentage	Duration Factor
LI-1	0%-80%	N/A
LI-2	80%-95%	N/A
LI-3	95%-99%	N/A
LI-4	>99%	Less than 9 hours above 100%
LI-5	>99%	More than 9 hours above 100%

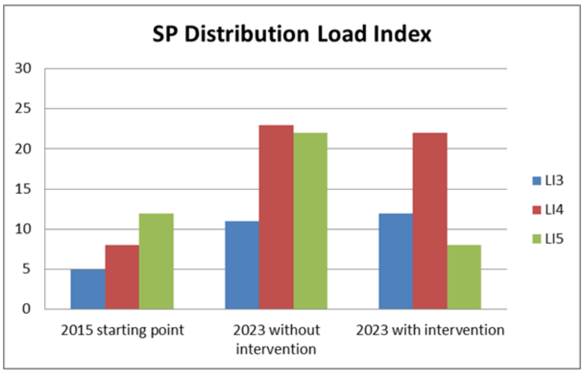
The Load Index methodology is an excellent method of achieving consistency of reporting across the industry, however, it is not the sole mechanism for triggering reinforcement projects. If the overload is marginal or there are special local factors, we may choose to manage the LI5 condition rather than intervene.

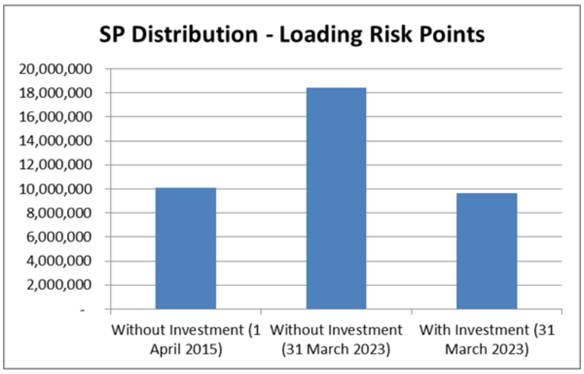
Network equipment is rated according to its energy carrying capacity. For some assets the recommended ratings take account of the duration of the maximum loading so that, for example, higher loadings (overloads) can be accommodated if accompanied by sufficient "cooling off" time. The likelihood of an asset becoming heavily loaded is often also related to the probability of failure of adjacent assets which share the load. Our assessment of network capacity therefore takes account of the shape of the loads carried, the duration of the peak, the overload capability of the assets and failure risk probabilities. For this reason, load indices can only be regarded as indicative and investment decisions require more in-depth analysis.

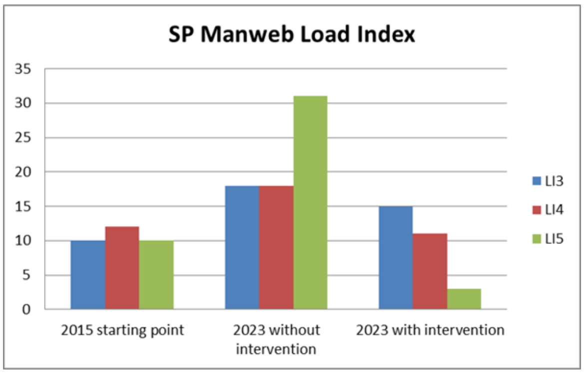
Previously we used a threshold of 120% loading to classify the most heavily loaded (LI5) assets which was higher than other DNOs. The process of standardising the LI definitions has highlighted that we have been running our assets harder than other DNOs. Over the course of DPCR5 we have been investing in our most heavily loaded assets, in line with the DPCR5 settlement. During ED1, we will tackle a further batch of assets to bring us more in line with other DNOs.

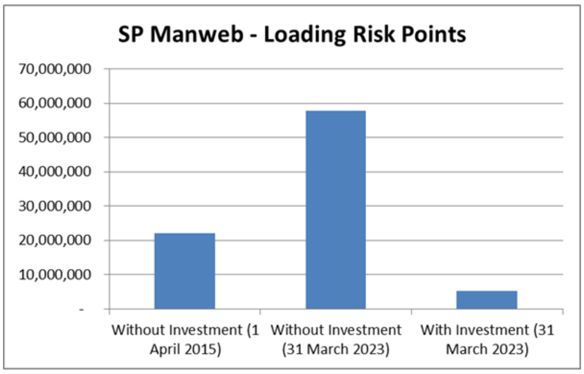
We also believe it is sensible to continue to monitor areas where theoretical achievement of LI5 status towards the end of the ED1 period is predicted to occur but that is dependent on the predicted load growth actually being achieved. These schemes will be closely monitored until we gain more certainty around the loading condition and the actual demand growth using our network monitoring and smart meter data as it becomes available.

The impact of our plans on the load indices for our networks is illustrated below. The load index charts illustrate the number of LI 3, 4 and 5 assets we will have on our networks by 2023 versus the number that would exist if we made no investment. The charts showing loading risk points show the aggregate network risk based on a weighted summation of load indices, with LI5s given the highest weighting. These provide an overall risk score for the networks and help to illustrate the impact of the load related investment.









7.5.3. Primary Network Reinforcement

Primary Network Reinforcement Expenditure (£m)						
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD		5.8	7.8	34%	29.1	62.6
SPM		10.4	13.1	25%	52.2	104.5
SPEN		**16.3**	**20.9**	**28%**	**81.3**	**167.1**

We forecast an expenditure of £167.1m on primary network reinforcement, with £115.8m (70%) of this covered by cost benefit analyses.

In RIIO-ED1 average annual expenditure on primary reinforcement will be higher than in DPCR5. This is a consequence of having to undertake a number of significant reinforcements which are relatively costly because of the scope of work involved. Load growth has some impact on our reinforcement requirements particularly later in the RIIO-ED1 period and our revised plan has deferred some investment into RIIO-ED2 as a result of lower load forecasts. However, the majority of our RIIO-ED1 expenditure is required to address substations that are already at or near the point where intervention is required.

In the process of developing our individual schemes, we have considered a variety of alternatives which have included different network configurations, the use of innovative/smart alternatives, as well as conventional solutions. Section 7 describes the approach we have taken to considering Smart Grid alternatives to network reinforcement.

Some notable schemes where the CBA approach has highlighted the economic use of an alternative approach include:

Crewe 132kV

We have opted to use a phase shifting transformer to allow for the connection of two independent groups which cannot normally be interconnected due to the system phase shift. This is a novel technology which has not been installed on the SPEN network previously and is heavily informed by the 33kV Quad booster trial being undertaken by UKPN LCNF project – Flexible Plug and Play. This approach avoids the need for the normal solution which would be the construction of a new 132kV circuit to connect different groups. Compared to the conventional approach, this offers a NPV of £11.04m benefit over a 45 year period against the baseline.

Lockerbie

Due to a voltage problem, the conventional approach was to construct a third 33kV circuit to support the network, however we have proposed an alternative dynamic voltage support approach which allows for the problem to be managed with additional control and intelligence. This approach offers a NPV of £1.56m benefit over a 45 year period against the baseline. This solution has also been replicated in a number of other projects with a similar benefit, including Langholm and Berwick.

Whitchurch

Three options were considered for this scheme due to the high costs of the solutions. Alternatives included alternative grid in-feeds, additional network connectivity and transformer replacement. Each of these approaches attracted different capital costs and risks associated with the different arrangements. We did not deem there to be any smart alternatives due to discussions with stakeholders and current loadings which necessitate the amount of additional capacity that would be required. We are already undertaking an LCNF project in Whitchurch that we expect will defer the need for the reinforcement however the amount of activity is necessitating a more substantial upgrade in the longer term.

Further information on the alternatives considered can be found in our Annex C7 – Smart Grid Strategy – Creating a network for the future – SPEN.

Our primary network reinforcement plans will deliver the following outputs:

Asset category	Outputs	
	SPM	SPD
EHV Overhead Line (km)	27	29
EHV Underground Cable (km)	59	92
EHV Circuit Breaker	242	171
EHV/HV Transformer	39	43
132kV Overhead Line (km)	24	n/a
132kV Underground Cable (km)	17	n/a
132kV Circuit Breaker	7	n/a
132kV/EHV Transformer	4	n/a

A number of other non-standard assets will be installed within our smart solutions. Assets such as the phase shifting transformer, voltage control and active network management do not have conventional equivalents and as such are classed as ‘other technology’ in our business plan tables.

In addition to providing capacity as defined by the Load Index changes described above, our primary network reinforcement investment addresses a number of other network issues:

Network reconfiguration

Our distribution networks have evolved over the past forty years to meet the needs of customers in the most economical way at the time the work was undertaken. In SPD, this has led to situations where a number of primary substations are supplied from the same 33kV circuits. The future uptake in demand has indicated that these arrangements are no longer suitable. Our plans include two schemes costing £9m to reconfigure our 33kV network to improve the supply arrangements and to provide additional circuit capacity to allow these substations to operate to their full potential.

Voltage uprating

A proportion of our HV distribution network in SPM, and to a lesser extent in SPD, is operated at a voltage level of 6.6kV. The 6.6kV system is a legacy from the early development of the distribution system. Modern networks are constructed to operate at 11kV and in recent years we have undertaken several projects to uprate certain areas from 6.6kV to 11kV. This releases additional latent capacity (as an 11kV system has greater capacity) and has the effect of reducing system losses. It is our intention to continue with a phased replacement of our 6.6kV network with a further six projects being undertaken in ED1 at a cost of £16m.

System voltage performance

Customers expect that the voltage at the point of their connection is acceptable and does not result in difficulties operating their electrical equipment. This expectation is supported by legislation in the form of the Electricity Safety, Quality and Continuity Regulations 2002 which sets out the voltage ranges which the network must be designed to maintain. The system is required to maintain the voltage to our customers within prescribed limits under all reasonably foreseeable loadings and configurations but, in some circumstances, this is no longer possible, and therefore intervention in the shape of a reinforcement or mitigation measure is required.

Within the RIIO-ED1 period, we will undertake nine projects at an approximate cost of £22m to resolve unacceptable voltage step conditions at the identified locations. Where practicable, we will be progressing technological solutions as opposed to conventional methods provided the solution provides sufficient headroom for future development.

Work to date has shown that we anticipate significant growth in small-scale embedded generation, especially LV-connected domestic PV, during the ED1 period and beyond. The connection of embedded generation tends to be constrained more by voltage limits rather than thermal (i.e. power flow) limits, especially in rural networks where the LV circuits are relatively long and the distribution transformers are relatively small.

The traditional reinforcement solution for LV-connected PV in these circumstances would be to uprate the pole-mounted transformer or alter the transformer fixed tap position (or both). This traditional solution is appropriate for low PV uptakes, but we anticipate that about 6.5% of our domestic customers will have a PV system installed on their home by the end of ED1. For this scenario, a more economic solution is to modify our voltage control methodology at the outset, rather than to start reinforcing the network at the beginning of ED1, only to have to modify the voltage control methodology towards the end of ED1 anyway.

Therefore, in addition to the nine voltage step projects mentioned above, our plans include a programme to enhance the functionality of our voltage control relays. This will extending their controllability (e.g. voltage set point) at both Primary and Grid substation sites via the Control Room. This enhancement will enable the network to be operated more flexibly in response to network need. The project will complement the voltage control relay modernisation programme (which is based on asset condition criteria) by including additional sites in areas likely to see the impact of small-scale generation, such as PV.

7.5.4. Secondary Network Reinforcement

Secondary Network Reinforcement Expenditure						
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD	11kV	2.9	3.7	31%	14.3	29.9
	LV	1.6	1.7	7%	8.1	13.9
	Total	**4.5**	**5.5**	**22%**	**22.4**	**43.8**
SPM	11kV	1.6	2.5	64%	7.8	20.4
	LV	0.8	0.9	12%	4.1	7.3
	Total	**2.4**	**3.5**	**46%**	**11.8**	**27.7**
SPEN		**6.8**	**8.9**	**31%**	**34.2**	**71.5**

Reinforcement expenditure on the secondary (HV and LV) networks has tended in the past to be low, as generally there was good understanding of the demands of customers supplied at these levels and sufficient headroom existed within the network to adapt to changes in electricity usage. Expenditure tended to be required to meet specific issues identified by single customers such as a voltage complaints.

Whilst the run rate of historic expenditure is expected to continue, during the next 10 years we expect the adoption of LCT will become the main driver for investment in the HV and LV network. The additional LCT related expenditure has been calculated using the TRANSFORM model.

The introduction of Smart Meters and additional network monitoring will help us to identify voltage problems or overloading more accurately than in the past. Our secondary network reinforcement investment includes the provision of 1300 secondary substation monitors. This will allow us to monitor the majority of LCT clusters that we are anticipating in our forecasts. Should these volumes be higher, we expect these to be clustered and as such this coverage would still provide the necessary visibility. We have included a separate annex, Annex C7 – Smart Grid Strategy – Creating a network for the future – SPEN, on our monitoring strategy that details the approach we are taking. This investment has been classed as secondary network reinforcement as the investment is due to load growth on the LV network.

7.6. Fault Level Reinforcement

Fault Level Reinforcement Expenditure (£m)						
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD		3.1	3.3	6%	15.4	26.2
SPM		3.0	2.9	-6%	15.2	22.9
SPEN		**6.1**	**6.1**	**0%**	**30.7**	**49.1**

£27.3m of our fault level reinforcement expenditure forecast is covered by cost benefit analysis.

When faults occur in the network it is possible for large amounts of fault current to flow through the system until this is interrupted by switchgear. Each item of equipment on the network is designed with a particular fault level capability.

Whilst the network has been designed to cater for these flows, it is possible from the increase in embedded generation and large motors connecting to the distribution network that the capability of the switchgear can be exceeded. This can lead to an increased risk of catastrophic failure of the switchgear when it operates. SPEN, like other Distribution Network Operators has a duty of care towards our employees and members of the public to ensure that they are not at risk of injury arising from failure of our assets.

Since fault levels are dependent on the network configuration and what is connected to the network at a particular period in time we undertake a periodic fault level survey using desktop analysis software, to identify locations were switchgear may operate above 95% of its rating. Sites identified by this screening analysis are then modelled in more detail to assess whether the actual duty exceeds 100% of the equipment rating. Where this occurs, mitigation measures are employed to manage the site-specific conditions.

Following the successful development of a fault level monitoring device through our innovation trials which commenced in 2010, we will in future validate the analytical modelling by deploying the monitor to key or affected sites in order that we have a robust and justified business case for investment to resolve fault level issues. We intend to further refine this analysis by deploying fault level monitoring equipment at key locations, this technology was developed through our innovation trials since 2010. This initiative is supported by our cost benefit analysis and will enable us to optimise our investment plans by more accurately tracking the development of fault level toward the switchgear rating. During the ED1 period, we will undertake twenty five projects with an approximate total of £49m.

In RIIO-ED1 we will continue to remove risks associated with operating switchgear above its fault level rating. A variety of solutions are considered for the site-specific condition but may ultimately require the replacement of the existing switchgear with higher rated equipment.

7.7. Smart Alternatives to Conventional Reinforcement

When developing solutions for system issues, we consider the deployment of 'smarter' solutions especially where that provides more economic solutions with quicker delivery timescales and minimisation of environmental impact. We commissioned Smarter Grid Solutions Ltd (SGS), who are an industry leader in smart grid technologies, to review over 100 of our major projects planned for ED1 to validate or identify alternative "smarter" solutions to conventional reinforcement. This allowed us to ensure that we embed the appropriate learning from industry technology trials and significantly reduce our investment plans

In total, this identified that up to 25 of these projects would benefit from adoption of innovative solutions as an alternative or complementary to conventional reinforcement. Each solution was validated to ensure that the technology was viable and would be available within the timescales required for project delivery. The solutions considered were:

- *Real Time Thermal Rating (RTTR) Transformer + Monitoring*
- *Fault Level Monitoring*
- *Smart Enabling of new substations*
- *Distribution Flexible AC Transmission Systems (D-FACTS) — HV connected STATCOM*
- *Active Network Management — Dynamic Network Reconfiguration*
- *Phase shifting transformer*

In a number of cases, the review identified opportunities to 'smart enable' new switchgear and associated substation and field equipment to provide the foundation for additional smart functionality and improved network management in future. Our project design proposals and investment plans have been updated to include the smart alternatives.

We have assumed that domestic demand side management (DSM) will have a very low role as a smart solution in ED1 as we believe that further work is required before it can be applied at scale with a high level of confidence. We have however considered the purchase of generator and/or I&C demand response as a smart solution within the reinforcement solution set. This is included within the solutions for secondary reinforcement and this has contributed to the overall costs savings.

Using innovative smart alternatives has reduced our primary network load plans by £40m.

7.8. Connections

7.8.1. Introduction

Customers who require a new or increased electricity supply need to obtain a new connection to the network. This includes all demand connections (customers who consume electricity), generation connections (customers who generate electricity and may need to export it into the network) and unmetered connections (For fixed loads only, with no meter connected, i.e. Street Lights, bus shelters, CCTV etc).

We provide an efficient, effective and comprehensive service to customers wanting to connect to our Electricity Network for a wide range of projects, from one-off connections to large residential, retail and industrial developments.

We facilitate competition in the connections market for 3rd Party Independent Connection Providers (ICPs) or Independent Distribution Network Operators (IDNOs), who want to connect to our network

The objective of connections outputs is to provide an excellent service for customers connecting to the network whilst facilitating competition in the connections market.

A range of Guaranteed Standards of Performance (GSOPs) to establish minimum levels of service are in place for all stages of the connections process. We will target zero failures in our guaranteed standards of service, if we do fail we will pay double the compensation required by Ofgem.

7.8.2. Competition in Connections

Competition in the connections market provides customers with a choice of options or companies who can provide some or all elements of the connection process.

We recognise that for effective competition to exist customers need to be aware that alternative providers are available and are able to make informed decisions on whether or not to use those providers.

There are 3 main types of quote

- *An Independent Connection Provider (ICP) quote. This is a quote issued by SPD or SPM to carry out non-contestable work only for a project where an ICP carries out the contestable work. The network is adopted by either SPD or SPM as appropriate.*

- *An Independent Distribution Network Operator (IDNO) quote. This is a quote issued by SPD or SPM to carry out non-contestable work only for a project where an IDNO will adopt the assets and where the contestable work is carried out by an ICP or an IDNO.*

- *A SPD or SPM quote. This is a quote issued by SPD or SPM to carry out all the works, contestable and non-contestable, associated with a new connection.*

Contestable activities are activities comprising or associated with the provision, modification, or retention of a connection to the licensee’s Distribution System that may, in accordance with the licensee’s Connection Charging Statement, be undertaken by persons other than the licensee.

Non-contestable activities are activities comprising or associated with the provision, modification, or retention of a connection to the licensee’s Distribution System that may not, in accordance with the licensee’s Connection Charging Statement, be undertaken by persons other than the licensee.

SPD and SPM have a proven track record of working with the industry to extend the boundaries of contestability. In 2002, we were amongst the first to put in place the processes and documentation necessary to offer live jointing trials. We are continuing to develop our processes and to work proactively with ICPs and IDNOs to extend competition.

Our key tasks have been to:

- *make live jointing of LV works on development sites a business as normal activity (achieved);*
- *enable ICPs to carry out closing joint works on both the existing SPM and SPD High Voltage (HV) and Low Voltage (LV) underground distribution cable networks (achieved);*
- *provide direct access to our Geographical Information System detailing full mains-records to facilitate contestable and non-contestable activities (access granted);*
- *initiate trials to undertake self determination of point of connection (trial offered, awaiting uptake); and*
- *be prepared to offer trials in operational access to distribution network (guidance has been document drafted).*

We are actively participating in the Ofgem working groups looking at extending contestability to part funded reinforcement. We will continue to support future work in this area, including engagement in any future Ofgem consultation

7.8.3. Expenditure Overview

The following table provides a summary of the different connection types.

Connections expenditure (by connection type) - Total RIIO ED1 (£M) Prime Costs			
	SPD	SPM	TOTAL
Demand Connections	66.7	99.5	166.2
DG Connections	132.8	217.5	350.3
Unmetered Connections	6.5	6.5	13.0
Total Connections Expenditure	206.0	323.5	529.5

Connection costs can be subdivided into two categories - sole use costs and network reinforcement costs.

Assets installed exclusively for the connection are called “sole use” assets and are funded by the Customer. As these costs are fully funded by the customer they are treated as being outside of the price control.

In some cases there is a requirement to increase the capacity of the existing network to enable the new connection to be made. The cost of this customer triggered reinforcement is shared between new connecting customers (customer funded reinforcement) and electricity distribution companies (DUoS funded reinforcement) following rules set out in the Electricity Act, Regulations and regulatory guidelines.

Reinforcement is defined as assets installed that add capacity (network or fault level) to the existing shared use Distribution System. The methods used to apportion the costs of the reinforcement are set in our published Connection Charging Statement.

The following tables show the how the connections prime costs are split between the three funding categories and the DUoS funded element as a percentage of total connections expenditure.

Demand Connections Expenditure - Total RIIO - ED1 £M Prime Costs			
	SPD	SPM	TOTAL
Sole Use	63.1	88.5	151.6
Customer funded Reinforcement	0.9	2.6	3.5
DUoS funded Reinforcement	2.7	8.5	11.2
Total Demand Connections expenditure	66.7	99.6	166.3

DG Connections expenditure - Total RIIO ED1 £m Prime Costs			
	SPD	SPM	TOTAL
Sole Use	127.8	125.4	253.2
Customer funded Reinforcement	2.7	40.2	42.9
DUoS funded Reinforcement	2.3	51.9	54.2
Total DG Connections expenditure	132.8	217.5	350.3

UMS Connections expenditure - Total RIIO ED1 £m Prime Costs			
	SPD	SPM	TOTAL
Sole Use	6.5	6.5	13.0
Customer funded Reinforcement	0.0	0.0	0.0
DUoS funded Reinforcement	0.0	0.0	0.0
Total DG Connections expenditure	6.5	6.5	13.0

DUoS expenditure - Total RIIO ED1 £m Prime Costs			
	SPD	SPM	TOTAL
Total DUoS funded expenditure	5.0	60.3	65.3
%age of total connections expenditure	2.4	18.7	12.3

7.8.4. Future Forecasts

To produce our forecast we analysed the various connections market sectors. A number of factors were considered.

The basis of the forecast was to consider the historic volumes of quotes issued, quotes accepted and market size for each market sector. Projections were forecast using this historic data to generate future run rates.

To allow the forecast to be refined, extensive Stakeholder engagement and market research took place analysing both the expected national growth and regional growth levels. Stakeholder engagement took place with numerous companies including National house builders, I & C Consultants, generation installers, to obtain their forecasts on build programs and likely growth within our area

Both the SPM and SPD areas have experienced significant development of Onshore wind farms and more recently Offshore Wind Farms and this is forecast to continue through the initial ED1 period. There has been an increase in the number of Connection quotes issued and accepted over the last 18 months which will result in peak expenditure between 2014 and 2018, Generations customers have obtained the benefits from the Renewable obligations (ROC) support schemes. The future forecasts have been based on known acceptances and identifiable customer delivery dates, supported by an assumption that government funding will continue.

The connections market is very competitive, and effective competition has developed in both our licence areas. We expect the competitive market to continue and the forecast has taken into account both the expected load growth and potential loss of market share to the competitive market.

We expect the effective cost per connection to reduce year on year as we develop more efficient processes and contracts to deliver the minor works. The anticipated effective price reduction per connection based on efficiencies is approximately 1% per year.

7.8.5. Market Segments Used in the Forecast

Connection projects have been categorised into a number of individual market segments, depending on the connection type. The list below shows the market segments used for demand connections.

LVSSA	Single service LV connection
LVSSB	Small project demand connection (LV)
LVAL	All other LV (with only LV work)
LVHV	LV end connections involving HV work
HVHV	HV end connections involving only HV work
LVEHV	LV end connections involving EHV work
HVEHV	HV end connections involving EHV work
EHV	EHV end connections involving EHV work
HV132	HV or EHV connections involving 132kV work
132kV	132kV end connections involving only 132kV work (SPM only)

The prime costs for the Demand Market Segments are shown in the following table.

Demand connections expenditure in RIIO - ED1 £m Prime Costs			
	SPD	SPM	TOTAL
LVSSA	4.7	6.0	10.7
LVSSB	10.3	8.1	18.4
LVAL	12.1	10.8	22.9
LVHV	26.6	13.8	40.4
HVHV	12.9	22.3	35.2
LVEHV	0.0	0.0	0.0
HVEHV	0.0	0.0	0.0
EHV	0.1	33.5	33.6
HV132	0.0	5.1	5.1
132 kV	0.0	0.0	0.0
Total	66.7	99.6	166.3

Distributed Generation (DG) projects have been categorised into a number of individual market segments, depending on the connection type, the list below show the market segments used for DG connections

DGLV	DG connections involving LV work only
DGHV	DG connections at HV involving HV work only
DGEHV	DG connections involving EHV work
DG132 (SPM Only)	DG connections involving 132kV work

The prime costs for the DG Market Segments are shown below.

Forecast DG connections expenditure in RII0 - ED1			
	SPD	SPM	TOTAL
DG LV	1.2	0.9	2.1
DG HV	33.9	18.3	52.1
DG EHV	97.7	52.7	150.4
DG 132	0.0	145.6	145.6
Total	132.8	217.5	350.3

Unmetered Connection projects have been categorised into a number of individual market segments, depending on the connection type.

UMLA	Unmetered Connection Activities in respect of local authority premises
PFI	Unmetered Connection Activities under private finance initiatives
OUMC	All other non-local authority and non-PFI unmetered connections work.

The following table shows the prime costs for the Unmetered Market Segments.

Unmetered connections expenditure in RIIO - ED1 £m Prime Costs			
	SPD	SPM	TOTAL
UMLA	6.1	6.1	12.2
PFI	0.0	0.0	0.0
OUMC	0.4	0.4	0.8
Total	6.5	6.5	13.0

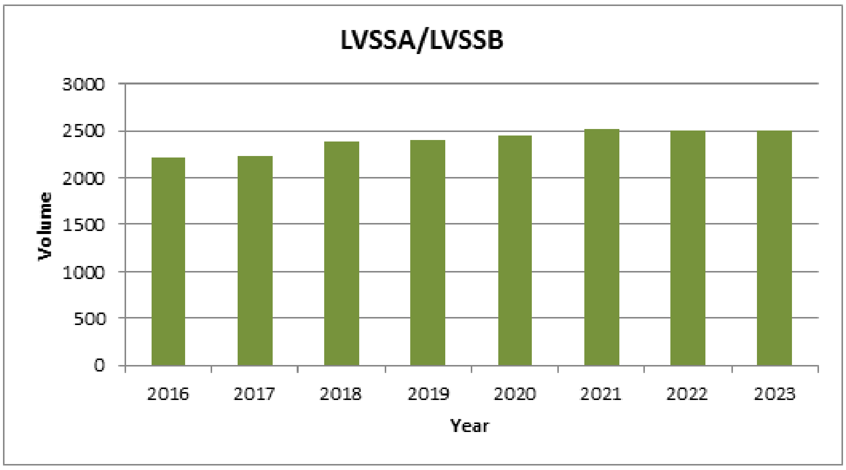
7.8.6. Future Connections Activity - Demand

The following table shows the forecast number of demand connections.

Forecast number of demand connection projects in RIIO - ED1			
	SPD	SPM	TOTAL
LVSSA	4733	5283	10016
LVSSB	5385	3831	9216
LVAL	2282	1759	4041
LVHV	1612	1081	2693
HVHV	486	598	1084
LVEHV	0	0	0
HVEHV	0	0	0
EHV	38	188	226
HV132	0	1	1
132 kV	0	0	0
Total	14536	12741	27277

7.8.7. Minor Connections (mainly LVSSA, LVSSB, market segments)

Activity within this market is predicted to remain stable, we have predicted that our existing market will remain constant. The following chart shows the forecast volumes for the LVSSA and LVSSB market Segments.



Housing (mainly LVAL and LVHV Market segments)

We expect this to remain a highly competitive segment and we will continue to ensure Customer Service is our main focus. There is likelihood that as competition increased we will lose market share. However, the impact is minimal as the overall market is expected to increase. To this effect the volumes predicted will increase from 2016 onwards.

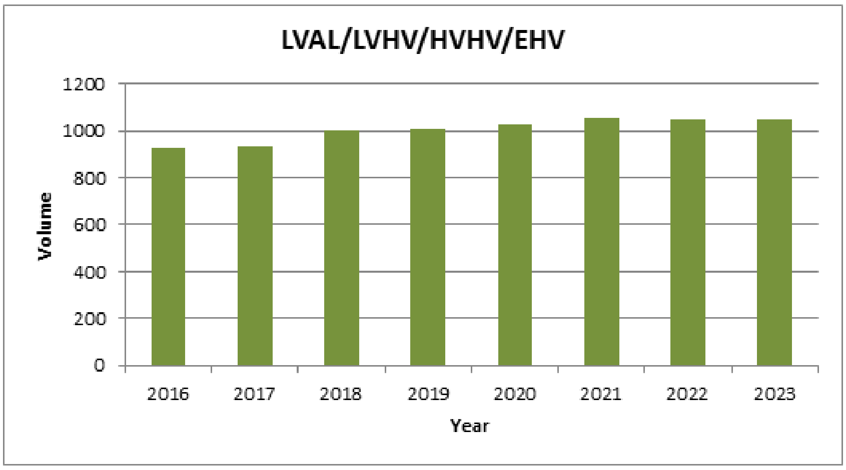
Industrial & Commercial (mainly LVAL, LVHV, HVHV and EHV segments)

The Industrial and Commercial market is expected to continue to grow due to forecasted investment in education and health, thereafter levelling off for the remainder of the ED1 period. Due to our work with stakeholders developing plans for the Glasgow and Liverpool areas, we are developing efficient proposals to assist in the regeneration of these cities and continuing to work with all the local authorities across our licence areas to respond quickly and efficiently to their development plans.

This is likely to remain a highly competitive segment and our business plan shows that we expect to maintain our existing market share despite this continued competition.

Although there is a rise predicted, we have aligned our business plan to show that our market segment will remain relatively stable for the remainder of the ED1 period in line with the stakeholder engagement discussed above.

The following chart shows the forecast volumes for the LVAL, LVHV, HVHV and EHV market Segments



Low Carbon Technology (Heat Pumps & Electric Vehicles)

We embrace low carbon technology and the opportunities it will provide and have aligned our business plan with the UK governments' vision for a low carbon economy in order to facilitate this transition.

A number of national incentives are available to promote the uptake of these new technologies, the Feed-In Tariff (FIT) which supports the low-carbon electricity using small-scale generation systems and the Renewable Heat Initiative (RHI) to promote and support renewable heating systems and technologies being installed.

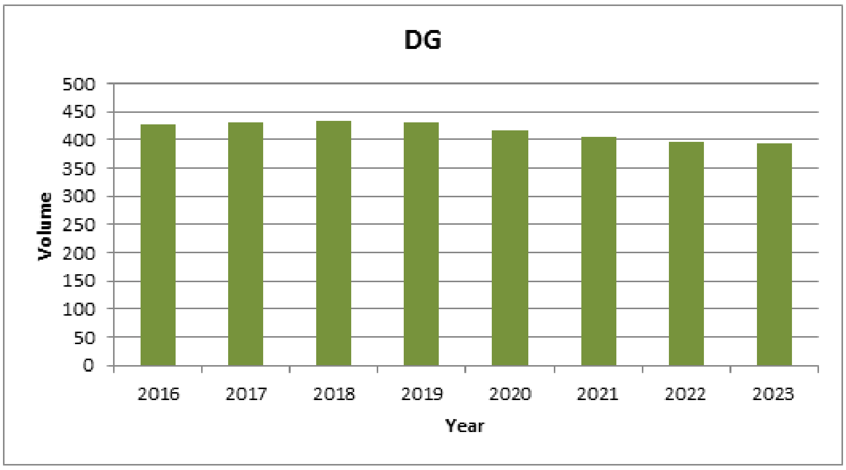
7.8.8. Future Connections Activity - Distributed Generation

The following table shows the forecast number of DG connections.

Forecast number of DG connections projects in RIIO - ED1			
	SPD	SPM	TOTAL
DG LV	1708	452	2160
DG HV	553	533	1086
DG EHV	48	16	64
DG 132	0	29	29
Total	2309	1030	3339

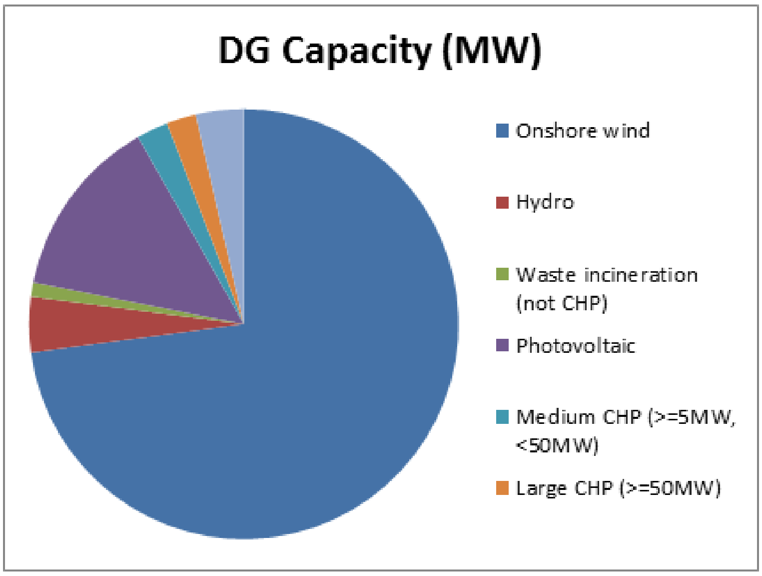
Both the SPM and SPD areas have experienced significant development of Onshore wind farms and more recently Offshore Wind Farms and this is forecast to continue through the ED1 period with connection of around 220MW of small scale DG and up to 4GW of larger DG connections including the Mid Wales scheme which facilitates connection of up to 650MW of generation.

There has been a large increase in the number of Connection quotes issued and accepted over the last 18 months which will result in peak expenditure between 2014 and 2018. Our forecast volumes for the DG market Segments are shown in the following chart and the table below shows the volumes split by generation type.



	2016	2017	2018	2019	2020	2021	2022	2023	
Total - No. of projects	**428**	**432**	**434**	**432**	**418**	**404**	**396**	**394**	**3,339**
Onshore wind	341	339	340	341	326	314	314	317	**2,632**
Offshore wind	-	-	-	-	-	-	-	-	**-**
Tidal stream & wave power	-	-	-	-	-	-	-	-	**-**
Biomass & energy crops (not CHP)	-	-	-	-	-	-	-	-	**-**
Hydro	39	41	41	41	39	38	38	38	**315**
Landfill gas, sewage gas, biogas (not CHP)	-	-	-	-	-	-	-	-	**-**
Waste incineration (not CHP)	1	1	1	1	1	1	1	1	**8**
Photovoltaic	45	49	49	47	50	49	41	36	**366**
Micro CHP (domestic)	-	-	-	-	-	-	-	-	**-**
Mini CHP (<1MW)	-	-	-	-	-	-	-	-	**-**
Small CHP (>=1MW, <5MW)	-	-	-	-	-	-	-	-	**-**
Medium CHP (>=5MW, <50MW)	1	1	1	1	1	1	1	1	**8**
Large CHP (>=50MW)	-	-	1	-	-	-	-	-	**1**
Other generation	1	1	1	1	1	1	1	1	**8**

The following figure shows the Distributed Generation capacity by generation type.



We will provide new photovoltaic connections as the market develops. It is expected that the current PV market will grow during this period and we have based our growth assumptions on the EATL V3 TRANSFORM model and consultation with our main Stakeholders

7.8.9. Future Connections Activity - Unmetered Connections

Our forecast for Unmetered connections is given below.

Forecast number of Unmetered connections in RIIO-ED1			
	SPD	SPM	TOTAL
UMLA	16465	18677	35142
PFI	0	0	0
OUMC	826	1210	2036
Total	17291	19887	37178

Competition has been established in this area and volumes of ICP tripartite works have increased steadily and we predict this trend to continue. SPM's market share has reduced year on year and we expect SPD market share similarly to follow this trend as the local authority are using Independent suppliers to complete their works.

7.8.10. Expansion of Scope of Contestable Work

Contestable activities are activities comprising or associated with the provision, modification, or retention of a connection to the licensee's Distribution System that may, in accordance with the licensee's Connection Charging Statement, be undertaken by persons other than the licensee.

Live Jointing Trials

We were amongst the first to offer live jointing trials in 2002. The ability to live joint newly adopted assets provided ICPs with considerably increased autonomy in the scheduling of phased works associated with a development site. This has been business as usual for a number of years and is included in our Common Connection Charging Methodology as contestable work.

Live Jointing of Existing Assets

We currently offer the final closing joints to existing LV and HV assets as a contestable activity.

The extension of contestability trials helped to facilitate further development of our practises and procedures and enabled us to actively encourage the wider ICP community to undertake this work across both our distribution services areas. This activity is no longer a trial and is included in our Common Connection Charging Methodology as contestable work.

Self-determination of point of connection

We have been developing a process to enable ICPs to carry out self-determination of point of connection associated with the LV network (up to 200 kVA). We have had discussions with a number of ICPs to facilitate the development of a procedural document to enable metered LV works in this area to be trialled. To date, we have received mixed views from a number of ICPs in this area and although some interest has been shown, with the exception of the unmetered market and multiple LV metered Small demand connections areas, trials have yet to progress.

Within the unmetered market, as part of the process for progressing extension of contestable LV closing joints, it is inherent that the ICPs carry out self-determination of the relevant point of connection.

Operational access to network

We have produced a guidance document on our website to facilitate enquiries for operational access to the distribution network. Whilst we have still to receive formal interest from ICPs wishing to progress this activity, we will be prepared to proactively engage with trials in this activity when they occur.

Part funded reinforcement work becomes contestable

We have actively participated in the Ofgem working groups looking at extending contestability to part funded reinforcement. We will support future work in this area, including engagement in any future Ofgem consultation.

7.8.11. Market Share Lost to Third Parties

Effective competition has developed and become established in all the Relevant Market segments in both the SPD and SPM Distribution Service Areas (DSAs). This is demonstrated by:

- *Collectively SPD (22.6%) and SPM (6.6%) distribution service areas (DSAs) having the highest percentage of MPANs connected to IDNO networks;*
- *Market shares;*
- *Number of competitors that are active in the market;*
- *Number of new competitors which have entered the market since 2010; and*
- *Measures that SPEN has taken to reduce potential and perceived barriers to entry.*

The LV and HV Market Segments in particular are highly competitive and attractive to competitors operating in the Competition in connections market. During ED1 these are likely to remain highly competitive Market Segments and we expect to maintain our existing market share despite this continued competition, due to our standard of customer service and proven delivery track record.

Ofgem established a formal process for all DNOs to demonstrate they have fulfilled all of their requirements in relation to competition in connections. In December 2013 Ofgem confirmed that SPEN successfully passed the competition test in four different market segments across our two licence areas.

7.9. Transmission Connection Points

Transmission Connection Point Expenditure (£m)						
		£m p.a.			Total	
		DPCR5	RIIO-ED1	% change	DPCR5	RIIO-ED1
SPD		0.0	1.0	-	0.0	7.8
SPM		0.0	0.0	-	0.0	0.0
SPEN		**0.0**	**1.0**	**-**	**0.0**	**7.8**

Our distribution networks are connected to transmission via Transmission Connection Points (TCPs). Our SPM network is connected to National Grid and our SPD network is connected SP Transmission. National Grid and SP Transmission provide infrastructure at these exit points to allow power to flow from the transmission system to the distribution network.

In Scotland, where transmission incorporates the 132kV system, we tend to have more Grid Supply Points with lower capacities. Following work carried out by SP Transmission during RIIO-T1, a number of sites were identified which would require reinforcement to increase capacity. This has been backed up by our more recent analysis and it is proposed that during RIIO-ED1 (and RIIO-T1) the existing grid transformers at Bonnybridge, Cupar, Galashiels, Sighthill and Strathleven will be replaced by higher capacity units. We have also aligned our asset replacement plans with upgrades at Sighthill and Strathleven to minimise overall costs.

Furthermore, based on analysis for RIIO-ED1, it is our intention to establish additional Connection Points at Tongland, Ecclefechan and Norham due to capacity constraints within the existing distribution network.

Within SPM, two GSPs will be subject to National Grid works within the RIIO-ED1 period (Carrington and Legacy). Neither of these will require investment funding in RIIO-ED1 as the associated costs will be covered by annual transmission exit charges. We are aware of other proposals which may affect TCPs however none of these have sufficient certainty for us to include them within our plan and the timing is likely to be in RIIO-ED2.

8. Non-Load Related Investment

8.1. Building Our Plans

Non-load related expenditure (NLRE) refers to the investments required for the replacement, refurbishment and life extension of the assets used on our networks. The main asset categories employed within our networks include:

- *Overhead lines*
- *Underground cables*
- *Switchgear*
- *Transformers*
- *Civil structures*
- *Protection and control equipment*

The process we have used to develop our non-load related investment involved the following steps.

- *We have undertaken a comprehensive analysis of the health of our existing asset base, making use of condition and performance information gathered through our inspection and maintenance processes and other data held within our asset management systems. We have also reviewed the consequence of failure of our assets and have used this information, along with our asset health assessments to quantify asset risk*
- *We have identified legal and safety issues of relevance to the asset base and have assessed the extent to which we need to undertake activity to ensure compliance with these obligations*
- *We have considered the opinions of our stakeholders and what is important to them*
- *We have carried out deterioration modelling across our assets to forecast how the health and performance will change over time*
- *We have reviewed the intervention options available including refurbishment, retrofitting or complete asset replacement, developing unit costs for all of the available intervention options*
- *Using the outcomes of the steps above, we have identified the assets that we need to address within the ED1 price control period and have identified the most cost-efficient interventions to be applied to manage the risks associated with the ageing of our assets*

8.1.1. Asset Health and Criticality Indices

Our investment plans are based on the condition of our assets and the consequences if they should fail. We assess these factors in a structured way, using a comprehensive Health Index methodology to categorise assets based on their condition.

HI Category	Description
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration requires assessment and monitoring
HI4	Material deterioration, intervention requires consideration
HI5	End of serviceable life, intervention required

New to the RIIO-ED1 period is the development of a Criticality Index to reflect the consequence of failure.

CI Category	Description
C1	Less than 75% of the average overall consequence of failure
C2	Between 75% and 125% of the average overall consequence of failure
C3	Between 125% and 200% of the average overall consequence of failure
C4	Greater than or equal to 200% of the average overall consequence of failure

By combining these indices, we are developing a detailed understanding of asset risk across the components that make up our network and this allows us to target our investment programmes on making the most cost-effective risk reduction interventions.

8.1.2. Health Index (HI)

Asset Health is influenced by a number of factors:

- *Design Standards — acceptability to the current specification*
- *Deterioration — range of decay from 'None' to 'Major' and which may include specific indicators (such as dissolved gas analysis results, inspections or maintenance data)*
- *Operational Issues — operational restrictions, fault levels, safe working procedures*
- *Vicinity and Location — indoor/outdoor*
- *Fault Rate — tolerance of rate within the asset base compared with others*
- *Critical Issues -identified critical defect*
- *Maintenance Spares — availability and suitability of parts and expertise*

We currently use our HI methodology for the following classes of assets:

- *11kV (ground mounted), 33kV and 132kV switchgear*
- *11kV (ground mounted), 33kV and 132kV transformers*
- *LV, 11kV, 33kV and 132kV wood poles*
- *132kV overhead line conductor*
- *33kV and 132kV overhead line towers*
- *132kV overhead line fittings*

We are continuing to develop the use of the HI methodology for other asset classes and in developing our ED1 plan, we have applied it in informing our proposals for LV pillars and substation buildings and structures.

8.1.3. Criticality Index (CI)

We have recently incorporated criticality assessment to enhance our asset management processes and have introduced the concept of the Criticality Index. The CI is a measure of the consequence of failure of an asset and our analysis takes account of 4 types of consequence:

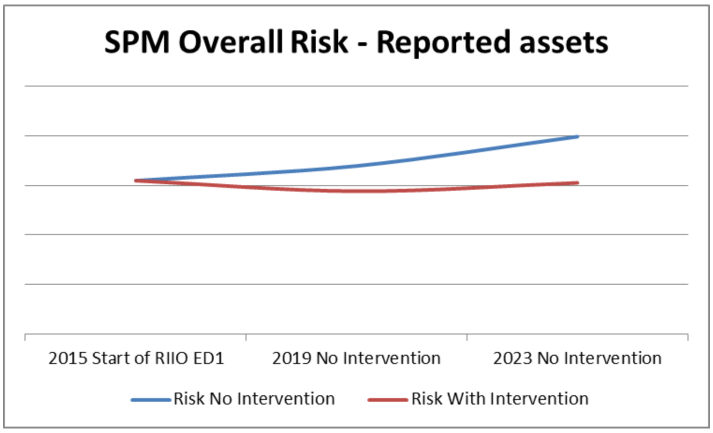
- *Safety*
- *System (which includes customer impact)*
- *Environmental*
- *Financial*

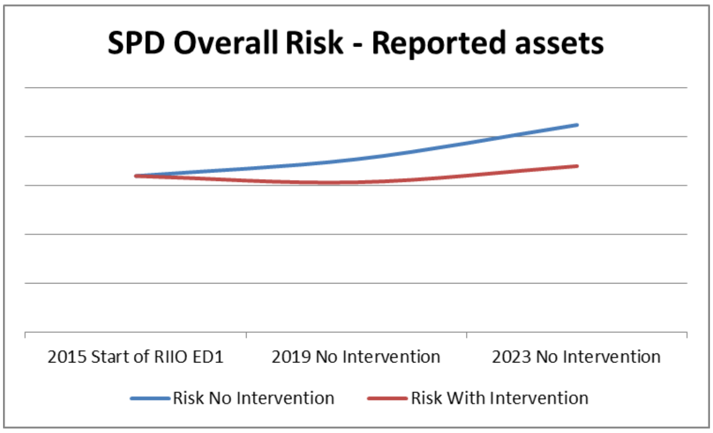
Each of these factors is assessed on a common basis to allow the results to be combined to provide an overall score for each asset. For each asset class, we then subdivide the population into 4 categories, running from CI1, the lowest critical rating to CI4, as defined above, which applies to assets with a significantly greater consequence of failure than the average for the asset class.

Further details of our approach to Health and Criticality assessment is set out in Annex B3 - Asset Health & Criticality Approach - SPEN.

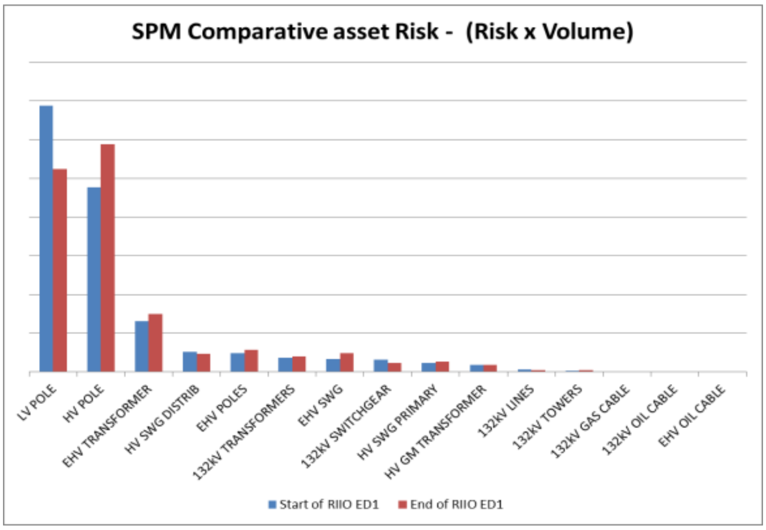
8.1.4. Asset Risk

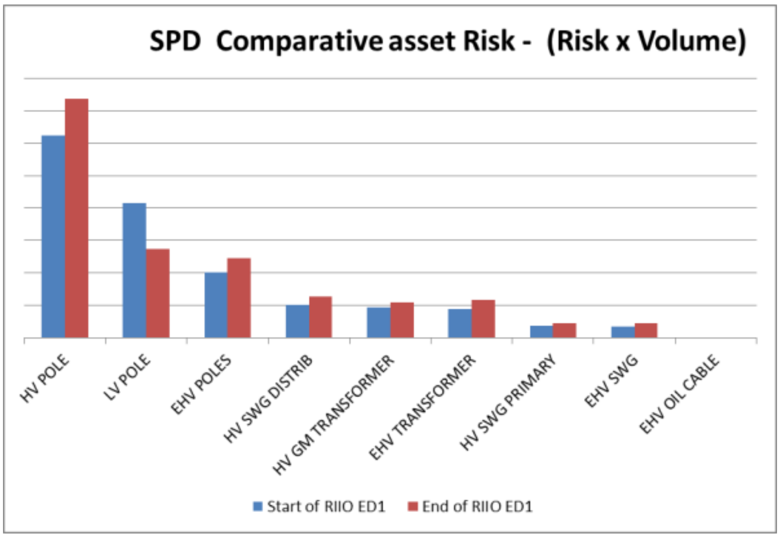
The charts below outline the comparative risk at the start and end of the RIIO ED1 period both with and without investment. This overall risk has been derived by calculating the risk on an asset type by asset type basis (probability of failure x consequence of failure) and then combining the sum of these separate asset risk components together. Asset risk will tend to increase over the period due to deterioration, which we aim to manage over the long term through our interventions.





We have also assessed the relative risk levels across the range of asset classes. The risk level from a particular asset class is a product of the average risk for the asset class multiplied by its population. As a result, asset classes with relatively low individual risk but high population can have a large overall impact. This is the case for wood pole assets which make the single largest contribution to overall risk for both licences.





8.1.5. Legal and Safety

Safety is at the forefront of everything we do, and we are fully committed to managing public safety and complying with all relevant health and safety regulations. We work closely with the Health and Safety Executive in the development of programmes to address key health and safety risks.

In developing our investment plan, we have assessed our legal and safety risks to ensure that we address issues that otherwise would present us with a level of intolerable risk.

In particular, we have 2 large programmes currently running in DPCR5 in this area and we intend to continue with these in ED1:

Overhead line low ground clearance

We are at the forefront of the industry in ensuring that all of our overhead lines meet modern height and clearance standards. We are on course to remove all of the highest risk ground clearance hazards (mainly road crossings) by 2015. For ED1, we have set a target of making our entire networks compliant by 2020

Rising Mains Programme

In DPCR5, we have established a pioneering programme to replace ageing electrical cables in flatted properties including high rises and tenements and are forecasting that we will have modernised services to 90,000 customers by March 2015. In ED1, we plan to carry out work at a further 300,000 properties.

8.1.6. Stakeholders

In developing our plan, we sought input from our stakeholders and have taken their views into account. Within the non-load investment areas, our stakeholders told us that they:

- *want us to renew our ageing network and to innovate to reduce future costs*
- *value the work we do to increase storm resilience and would support an Increase in the rate at which we add resilience*
- *consider flood risk mitigation to be a high priority*

We provide more detail on incorporating the views of stakeholders into our plans in the supplementary Annex B3 - Learning from Stakeholders - SPEN.

8.1.7. Deterioration Modelling

To determine our network investment needs, we have considered both the current condition and performance of our network assets and how we expect these to deteriorate over time. We have used long term age-based modelling to develop future capital expenditure volume forecasts and predict potential peaks in workload.

Our age based modelling methodology complements the detailed condition assessment process, enabling immediate and longer term risks to be adequately managed. The asset replacement model records information relating to age, voltage and circuit parameters for the different categories of assets employed on our networks.

We have modelled age-based deterioration in two ways:

We have applied our view of an average asset life to each asset category to determine future long term replacement volumes. The asset life has been determined using a combination of:

- *industry available information*
- *knowledge gathered from our own activities*
- *independent reviews by leading industry consultants*
- *We have also used actual historic replacement volumes to provide an inferred asset life which is then used to predict future replacement volumes. This approach provides a view based on the continuation of historical trends and provides a useful comparison with the first approach.*

Techniques and approaches for predicting asset deterioration continue to evolve. During planned interventions such as maintenance and repairs, and through the application of condition monitoring equipment we will continue to enhance our knowledge of asset condition and deterioration.

8.1.8. Selecting Intervention Options

Manufacturers specify the nominal design life for network assets under typical operating conditions. Within our regions, the environment within which our assets operate can vary significantly from exposed coastal and mountainous areas to relatively benign inland urban areas. The prevailing environmental conditions together with the service duty (e.g. number of operations, demand etc.) placed on an asset can all have an impact on its actual life, meaning that some assets last for either a longer or shorter time than their nominal life expectancy.

In circumstances where it is technically feasible and economic, we extend the life of our assets through refurbishment or retrofit. This involves replacing part of the asset with new components. In some situations, it is possible to introduce a new "modern equivalent" component that has additional advantages such as improved functionality or performance.

Where assets have failed or reached the end of their working life and cannot be refurbished or repaired economically, we replace them with their modern equivalent. This can involve adopting new technology. Examples of this include replacing oil filled switchgear with SF6 or vacuum types, replacing gas-compression and oil-filled cables with modern crosslinked polyethylene (XLPE) cable, and replacing electro-mechanical control relays with digital equipment, offering significant improvements in functionality and performance.

8.1.9. Identifying Investment Requirements

We have undertaken an extensive exercise taking account of the current condition and performance of our asset base, its consequences of failure, how it will deteriorate over time, the views of our stakeholders and our legal obligation to identify the most appropriate set of interventions to make during the ED1 period.

Given the long-term nature of our Business, this analysis has been conducted over a period spanning a number of price controls in order to ensure that the interventions we are looking to make in ED1 represent the optimal plan.

In undertaking this work, we have used our specialist Asset Stewardship Groups which bring together asset management, design, operational and delivery experts for each asset class to consider all of the relevant factors to determine our plan. We have also undertaken a comprehensive suite of cost benefit analyses (CBAs) to ensure that we are investing in the right solutions on the right assets at the right time.

8.1.10. Forecasting Method for Each Asset Category

The method used to forecast our volumes for the RIIO-ED1 business plan for each asset is summarised in the table below.

Forecasting method by asset type	
Asset	**Forecasting method**
UG- LV main (Consac)	Removal of remaining volume
UG- LV main (Paper)	Forecast on fault rates and replacement run-rate
UG- LV main (Plastic)	Forecast on fault rates
UG- LV service	Forecast on fault rates and replacement run-rate
UG- HV and 33kV cable	Forecast on fault rates and replacement run-rate
UG- 132kV cable	Circuit specific condition and performance
OH- LV Services	Forecast on fault rates and replacement run-rate
OH- LV conductor	Forecast on replacement run-rate
OH- HV and 33kV conductor	Forecast on condition and resilience requirement
132kV conductor	Economic replacement age and condition related forecast
OH- LV, HV, 33kV and 132kV pole	Forecast on condition and resilience requirement
OH- Pole refurbishment	Forecast on fault rate and historic delivery levels
OH- Tower replacement	Circuit specific condition
OH- Tower refurbishment	Circuit specific condition
OH- Tower fitting replacement	Circuit specific condition
OH- Tower painting	Circuit specific condition
OH- Tower foundation	Circuit specific condition
SG- Cut-out replacement	Forecast on fault rates and replacement run-rate
SG- Link boxes and pillars	Forecast on fault rates and replacement run-rate
SG- HV and 33kV switchgear	Forecast on condition
SG- 132kV switchgear	Forecast based on site specific condition
Tx- HV GM	Forecast linked to RMU replacement and losses reduction requirement
Tx- HV pole mounted	Forecast linked to OH refurbishment
Tx- 33kV and 132kV transformers	Forecast on site specific condition
PR- Batteries	Forecast on replacement run-rate and black start requirement
Civil driven by Asset replacement	Directly driven from plant asset replacement activity
Civil driven by condition (HV)	Forecast based on historic activity levels
Civil driven by condition (33kV and 132kV)	Forecast based on site specific condition

8.2. Asset Replacement and Refurbishment

8.2.1. Overview

Many of our assets were installed in the 1950s and 1960s and as a consequence we require to proactively manage an ageing asset base to ensure the safe and reliable operation of our network for all customers.

With a significant proportion of our assets nearing the end of their useful lives there is a requirement for us to invest in asset renewal to avoid long-term deterioration in overall asset health and the consequential impact on reliability of customer supplies.

We use health indices, now enhanced by criticality assessment, to identify and prioritise our investments which take into account asset condition, fault rates, safety risks, maintenance requirements and equipment and manufacturer obsolescence.

During the current regulatory period we have invested in systems and developed processes to improve our understanding of the health of our asset base. Condition assessments are carried out through regular inspections and maintenance activities to inform our plans.

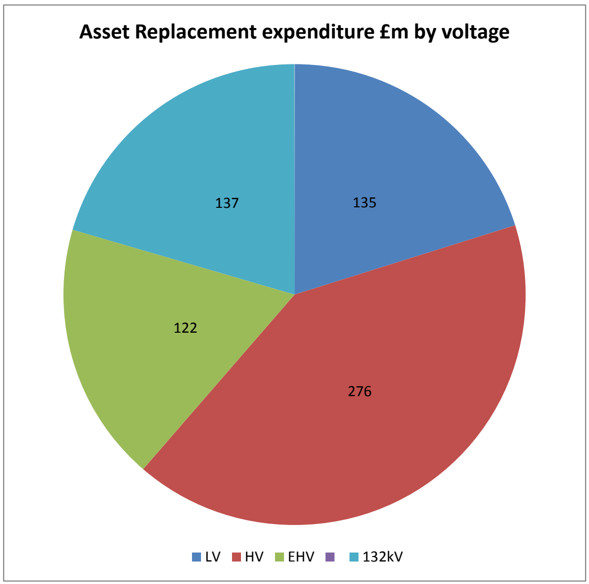
Network investment is prioritised through structured risk assessment to where it is required most and has the greatest benefit to our customers.

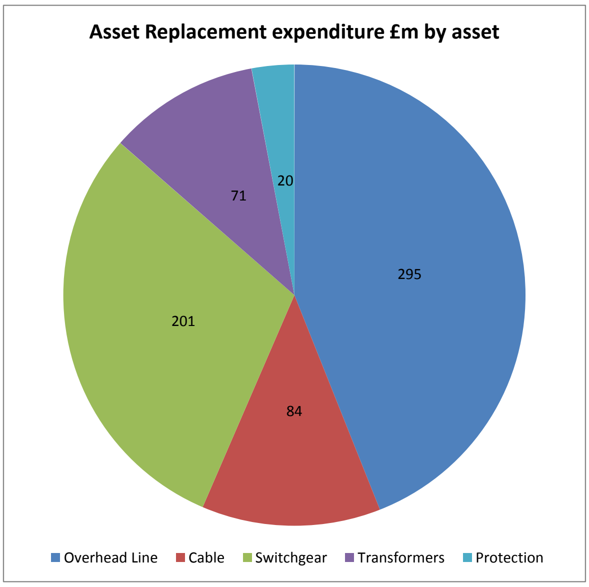
8.2.2. Asset Replacement and Refurbishment Expenditure Forecast Summary

The following tables and charts summarise our investment across the different types of asset for replacement and refurbishment interventions and provides a comparison with DPCR5 investment.

Asset Replacement Expenditure	DPCR5		RIIO -ED1				% Difference Per Annum	
	Per Annum (£m)		Total (£m)		Per Annum (£m)			
	SPD	SPM	SPD	SPM	SPD	SPM	SPD	SPM
LV Main (OHL) Conductor	1.23	2.58	10.01	20.94	1.25	2.62	2%	1%
LV Service (OHL)		0.02	2.85	4.74	0.36	0.59		
LV Poles	1.11	2.66	8.88	16.13	1.11	2.02	0%	-24%
LV Main (UG Plastic)	0.53	0.70	8.05	9.52	1.01	1.19	88%	70%
LV Service (UG)	0.68	1.85	3.42	7.68	0.43	0.96	-37%	-48%
LV Pillar (ID)	0.40	0.00	0.09	0.23	0.01	0.03	-97%	512%
LV Pillar (OD at Substation)	0.31	0.03	1.84	0.46	0.23	0.06	-25%	80%
LV Board (WM)			0.64	0.80	0.08	0.10		
LV UGB & LV Pillars (OD not at Substation)	1.80	1.76	13.71	12.39	1.71	1.55	-5%	-12%
Cut Out (Metered)	1.20	0.76	7.58	4.99	0.95	0.62	-21%	-17%
6.6/11kV OHL (Conventional Conductor)	3.37	2.27	29.62	27.44	3.70	3.43	10%	51%
6.6/11kV Poles	3.73	4.14	43.76	40.44	5.47	5.05	47%	22%
6.6/11kV UG Cable	0.88	1.19	10.25	13.65	1.28	1.71	45%	43%
6.6/11kV CB (PM)	0.28	0.06	1.61	1.27	0.20	0.16	-29%	187%
6.6/11kV CB (GM) Primary	1.54	3.84	11.47	10.30	1.43	1.29	-7%	-66%
6.6/11kV CB (GM) Secondary	0.35	0.29	5.41	3.53	0.68	0.44	93%	52%
6.6/11kV Switch (PM)	0.23	0.07	0.24	0.43	0.03	0.05	-87%	-18%
6.6/11kV Switchgear - Other (PM)	0.08	0.09	0.79	0.76	0.10	0.10	19%	0%
6.6/11kV Switch (GM)	0.27	0.03	1.71		0.21		-22%	-100%
6.6/11kV RMU	2.31	1.97	11.20	6.47	1.40	0.81	-40%	-59%
6.6/11kV X-type RMU		2.90		26.64		3.33		15%
6.6/11kV Transformer (PM)	0.53	0.27	3.05	4.09	0.38	0.51	-27%	87%
6.6/11kV Transformer (GM)	0.47	1.21	2.37	2.50	0.30	0.31	-37%	-74%
33kV OHL (Pole Line) Conductor	1.85	0.60	5.52	3.87	0.69	0.48	-63%	-19%
33kV Pole	1.04	0.24	8.56	5.72	1.07	0.72	3%	195%
33kV OHL (Tower line) Conductor	0.02		3.80	3.53	0.47	0.44		
33kV Fittings			1.52	1.42	0.19	0.18		
33kV UG Cable (Non Pressurised)	0.98	0.89	6.85	5.83	0.86	0.73	-13%	-18%
33kV CB (Air Insulated Busbars)(OD) (GM)		0.02	0.71	8.06	0.09	1.01		
33kV CB (Gas Insulated Busbars)(ID) (GM)	1.91	2.28	11.66	16.14	1.46	2.02	-24%	-12%
33kV Switch (GM)			0.88	4.80	0.11	0.60		
33kV Transformer (GM)	2.37	1.96	15.59	15.41	1.95	1.93	-18%	-2%
132kV OHL (Pole Line) Conductor		0.60		6.05		0.76		26%
132kV Pole				5.40		0.67		
132kV OHL (Tower Line) Conductor		0.87		28.91		3.61		317%
132kV Fittings		0.47		15.45		1.93		311%
132kV UG Cable (Non Pressurised)		3.75		18.54		2.32		-38%
132kV CB (Air Insulated Busbars)(ID) (GM)				2.69		0.34		
132kV CB (Air Insulated Busbars)(OD) (GM)		3.03		1.64		0.21		-93%
132kV CB (Gas Insulated Busbars)(ID) (GM)		2.66		25.07		3.13		18%
132kV Switchgear - Other		1.57		4.43		0.55		-65%
132kV Transformer		2.65		27.83		3.48		31%
Batteries at GM HV Substations	0.003	0.230	0.24	1.26	0.03	0.16		-32%
Batteries at 33kV Substations	0.12	0.23	0.76	1.14	0.10	0.14	-20%	-37%
Batteries at 132kV Substations		0.00		1.08		0.14		
Pilot Wire Overhead			0.36	1.45	0.05	0.18		
Pilot Wire Underground	1.19	0.96	6.23	7.43	0.78	0.93	-35%	-4%
Total	**30.8**	**51.7**	**241.2**	**428.6**	**30.2**	**46.2**	**-2%**	**-11%**

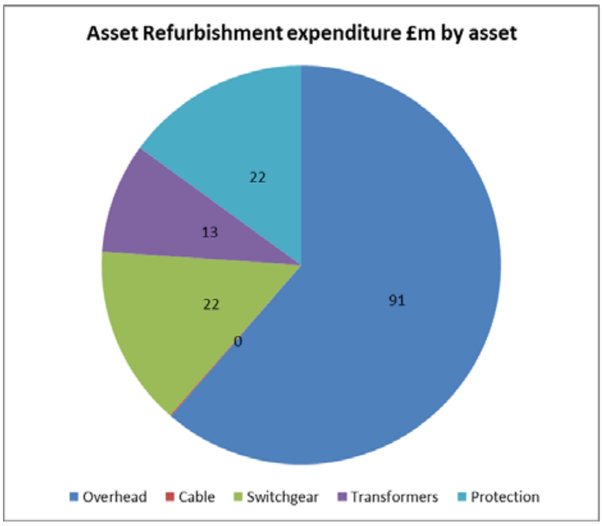
Asset replacement is spread across all voltages with most expenditure on the HV network and overhead lines where the largest impact on reliability and availability is seen by customers.

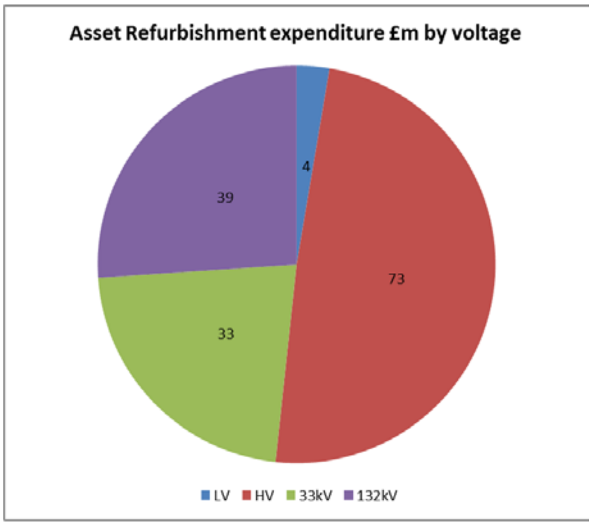




Asset Refurbishment Expenditure	DPCR5		RIIO -ED1				% Difference Per Annum	
	Per Annum (£m)		Total (£m)		Per Annum (£m)			
	SPD	SPM	SPD	SPM	SPD	SPM	SPD	SPM
LV Poles			0.66	1.36	0.08	0.17		
6.6/11 kV Poles	4.02	3.58	20.19	19.07	2.52	2.38	-37%	-33%
HV Transformer (GM)		0.11		6.30		0.79		635%
6.6/11kV CB (GM) Primary	0.02	0.04	9.22	9.27	1.15	1.16		
6.6/11kV RMU			1.15	0.14	0.14	0.02		
33kV Pole	0.39	0.43	3.38	2.25	0.42	0.28	8%	-34%
33kV Tower			1.47	1.35	0.18	0.17		
33kV Tower Painting			1.10	1.77	0.14	0.22		
33kV Tower Foundation			2.52	3.07	0.32	0.38		
33kV Transformer (GM)	0.24		3.67	1.74	0.46	0.22	92%	
33kV UG Cable (Oil)			0.08		0.01			
132kV Tower		2.25		8.03		1.00		-55%
132kV Tower Painting		0.47		8.34		1.04		120%
132kV Tower Foundation		0.03		16.21		2.03		
132kV Transformer				1.53		0.19		
132kV UG Cable (Oil)				0.08		0.01		
HV Protection		0.00	3.10	4.17	0.39	0.52		
EHV Protection	0.17	0.27	4.96	5.54	0.62	0.69	267%	157%
132kV Protection		0.21		4.42		0.55		158%
LV Street Furniture	0.04	0.34	0.38	1.52	0.05	0.19	26%	-44%
Total	**4.9**	**7.7**	**51.9**	**96.2**	**6.5**	**12.0**	**33%**	**56%**

Asset refurbishment is spread across the higher voltage assets with most expenditure on the HV network (switchgear and pole refurbishment) and overhead lines (towers and pole refurbishment).





8.2.3. Long Term Strategy

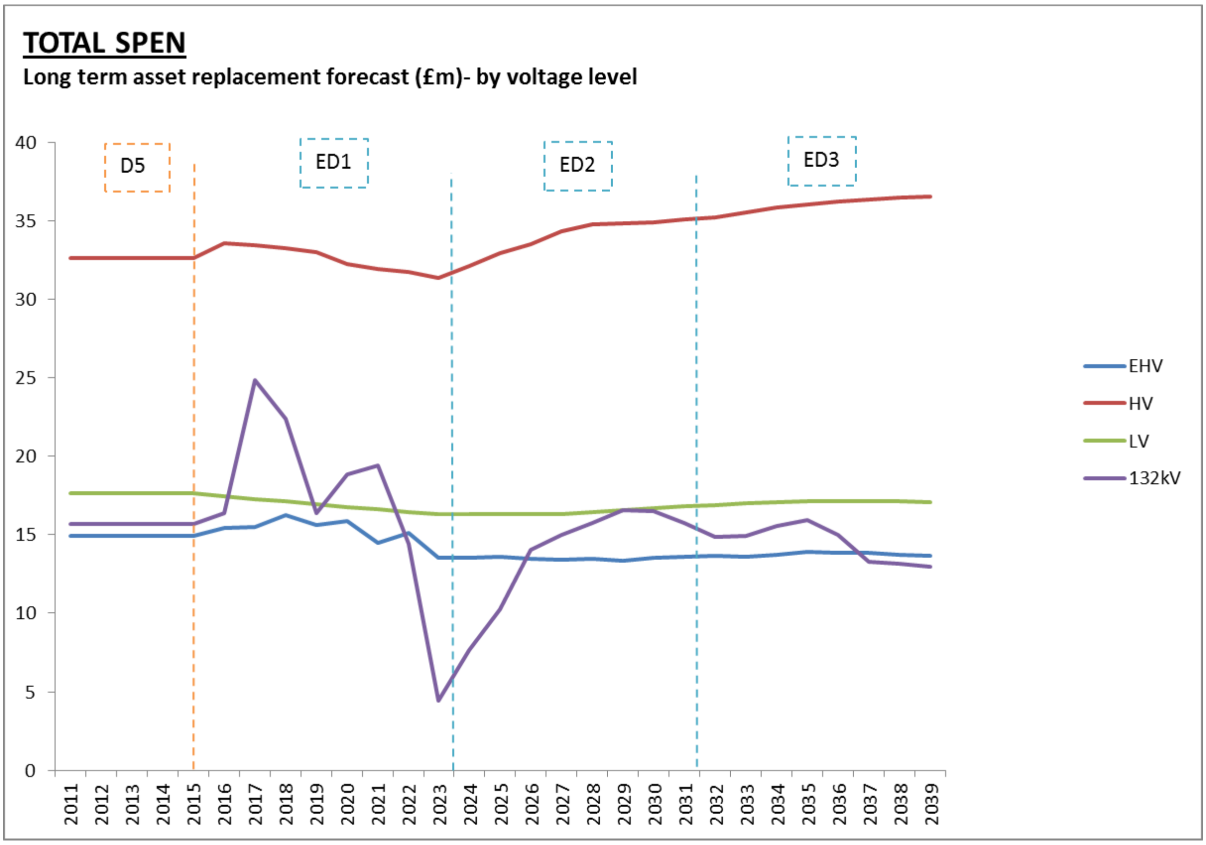
Our long term strategy to manage our assets takes account of the following likely outcomes:

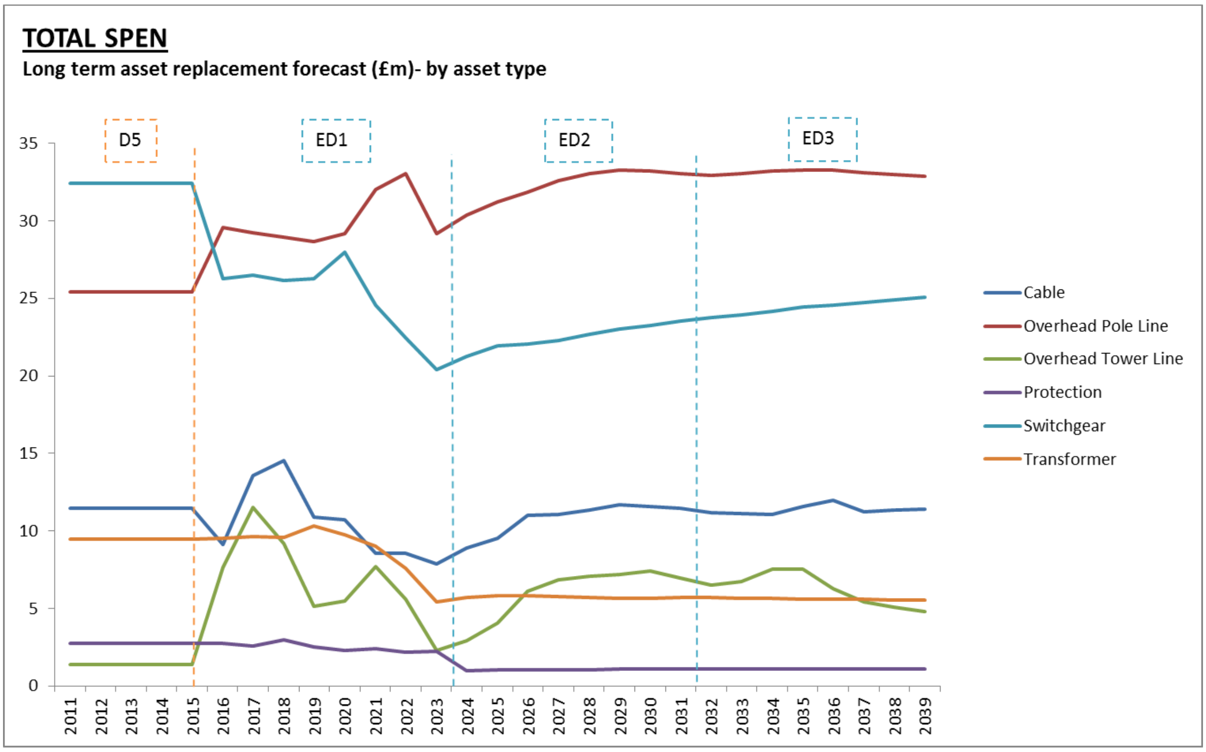
- *Increasing requirement to manage asset degradation arising from ageing of our asset bases*
- *Higher expectations for network reliability and availability as customers become more dependent on electricity for heating and transport*
- *Continued downward pressure on customer bills*
- *Increasing frequency of extreme weather events and the consequent need to make the networks more storm resilient*
- *Availability of increasing amounts of smart metering and network data (end ED1/ ED2)*
- *More stringent environmental requirements*

We are responding in the following ways:

Investment	Deploying more asset life extension through refurbishment as an alternative to replacement Rationalising legacy network issues, for example uprating our 6.6kV networks to 11kV Developing enhanced resilience to natural (storms, floods) and man-made events (cyber security) Increasing standardisation of assets within the Iberdrola Group and broadening the supply chain to increase competition between our suppliers and enlarge delivery capacity Implementing stringent energy loss reduction, oil and SF6 leakage requirements in our specifications
Skills/ Resources	Retaining core delivery capability in-house which will be supplemented by contractor resources to meet peak periods of workload Levering the benefits of access to resources and knowledge across an international group (for example, on smart meter deployment) Strongly supporting learning and implementing best practice from external sources or from within the Iberdrola
Innovation Priorities	Developing enhanced condition monitoring and network automation Integrating data management and analysis tools for large data sets into existing and new corporate systems (e.g. smart meter data for enhanced network planning processes and quantification of losses) Developing new approaches to maximise asset lives and defer asset replacement

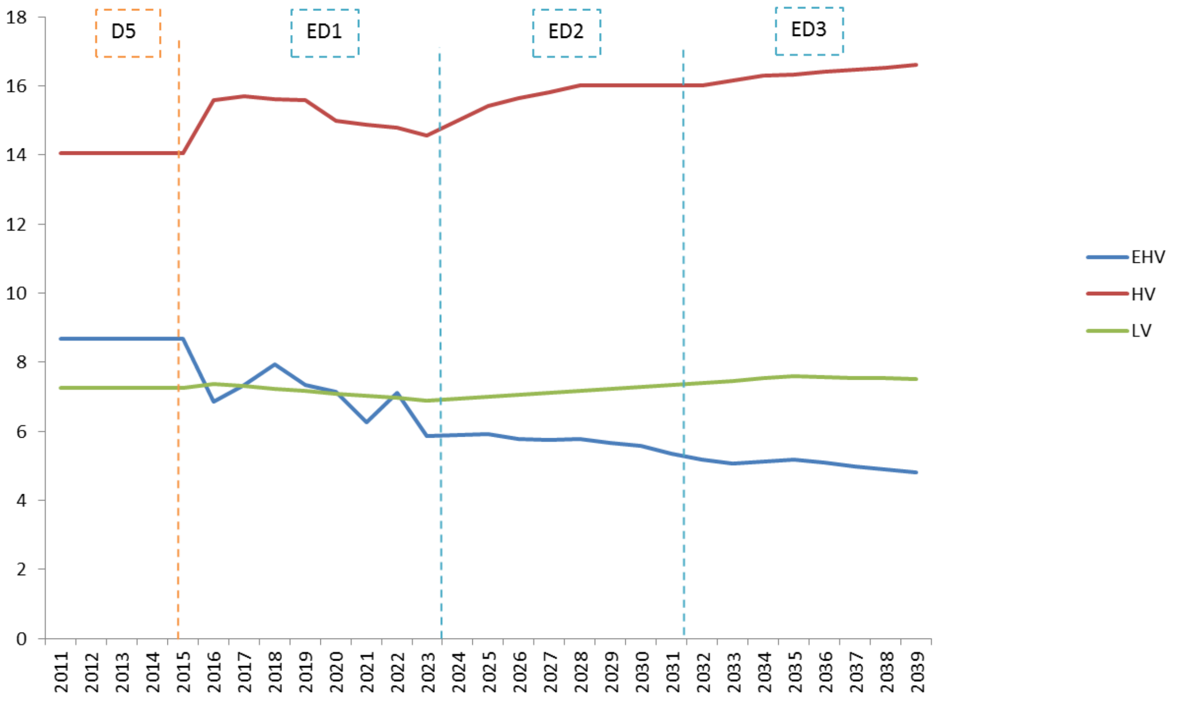
The following charts provide a longer term view of our forecast asset replacement over the next 30 year period.





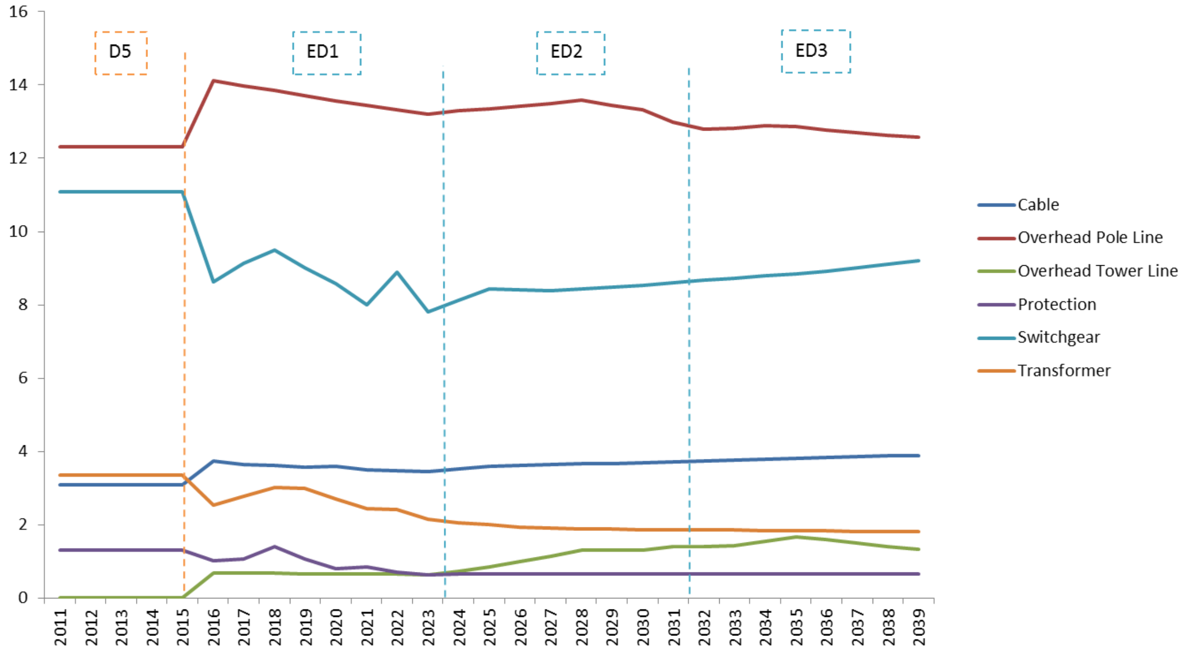
SPD

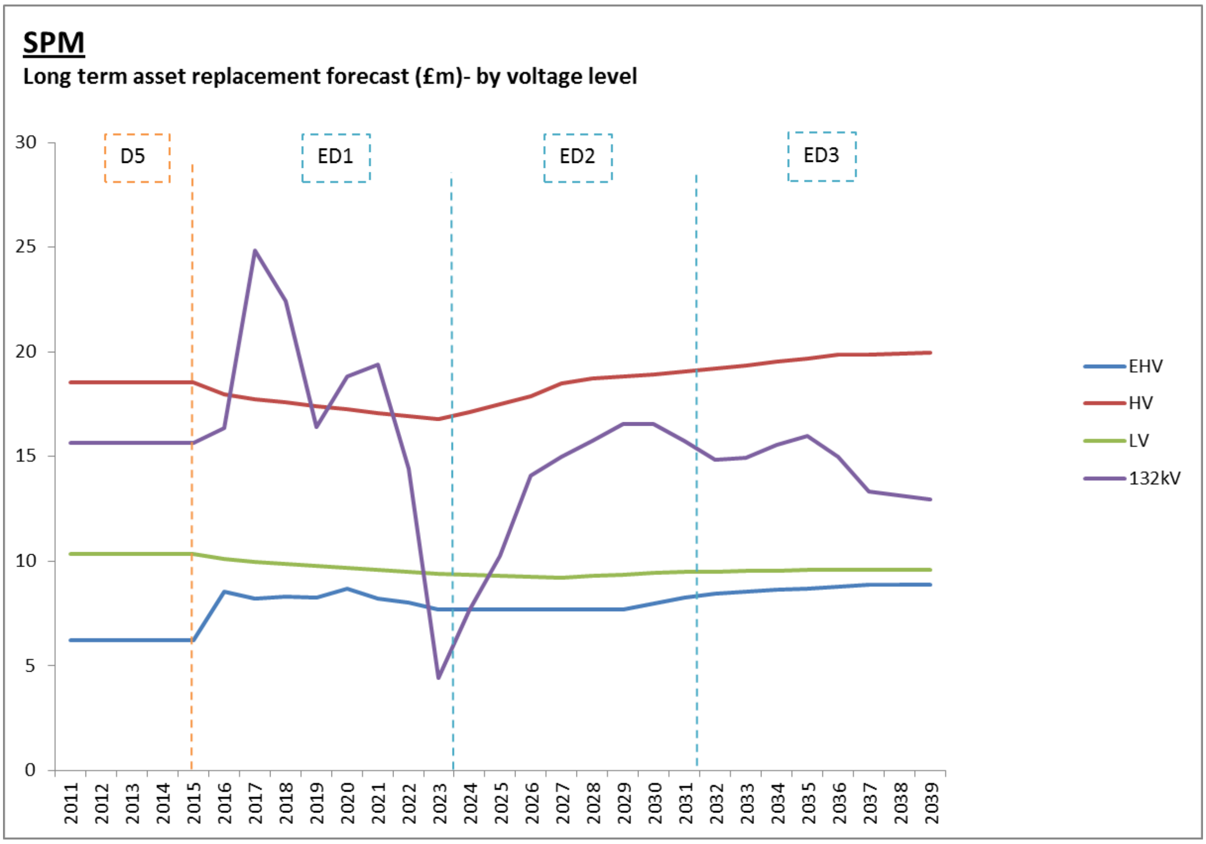
Long term asset replacement forecast (£m)- by voltage level



SPD

Long term asset replacement forecast (£m)- by asset type




SPM
Long term asset replacement forecast (£m)- by voltage level
D5
ED1
ED2
ED3
EHV
HV
LV
132kV
30
25
20
15
10
5
0
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
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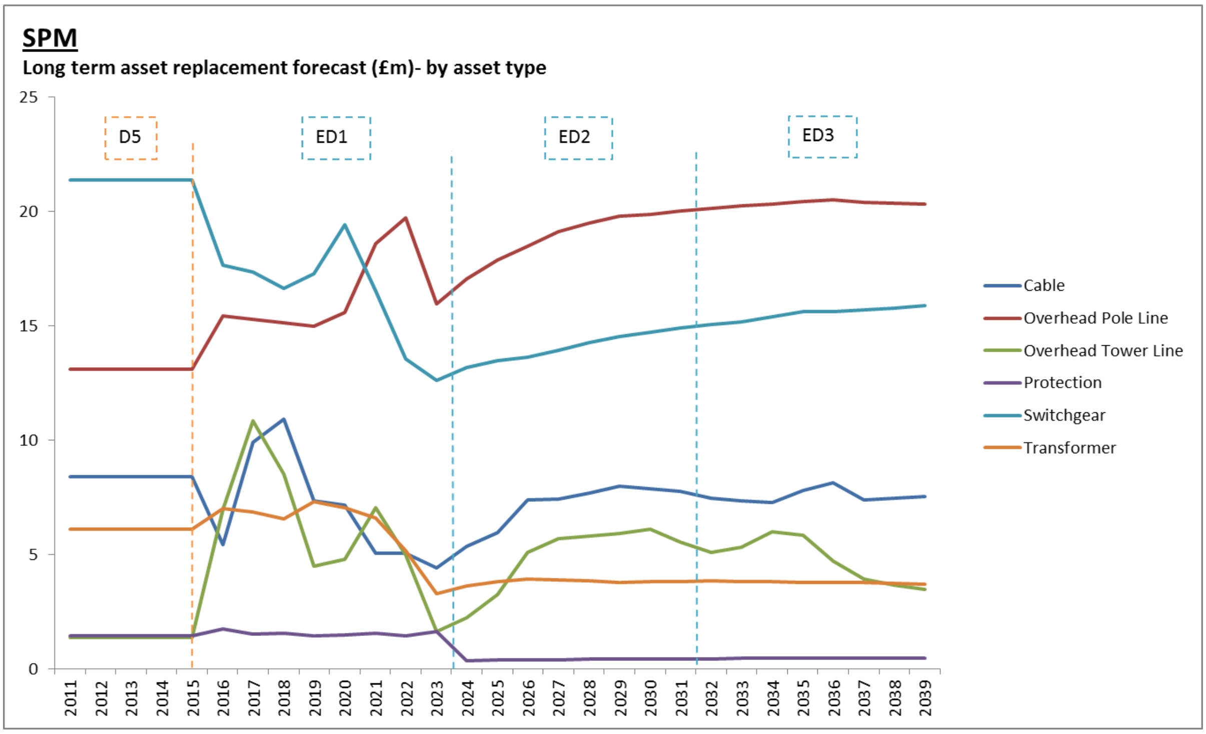
2036
2037
2038
2039


SPM
Long term asset replacement forecast (£m)- by asset type
D5
ED1
ED2
ED3
Cable
Overhead Pole Line
Overhead Tower Line
Protection
Switchgear
Transformer
25
20
15
10
5
0
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039

8.3. Detail of Asset Replacement and Refurbishment Expenditure

Detail of the expenditure, volumes and relevant information for each asset category is provided below. Further detail can be found in the associated supplementary annexes, which are referred to where appropriate.

8.3.1. Underground Cables Strategy

Our underground cable assets are essential to provide our customers with reliable electricity supplies.

Proactive cable replacement is targeted at poorly performing cable identified through analysis of faults on our network. This translates into programmes of work to replace health index 5 cables at 132kV, poor condition sections of cable at 33kV and 11kV and particular types of cable at LV.

In order to achieve our primary outputs, we have a developed a prioritised, fully justified and efficient plan for our cable assets.

For further detail on our Underground Cable Strategy please refer to ANNEX C6 – 132kV Cables Strategy - SPEN.

8.3.1.1. LV Underground Cables

Our Plan

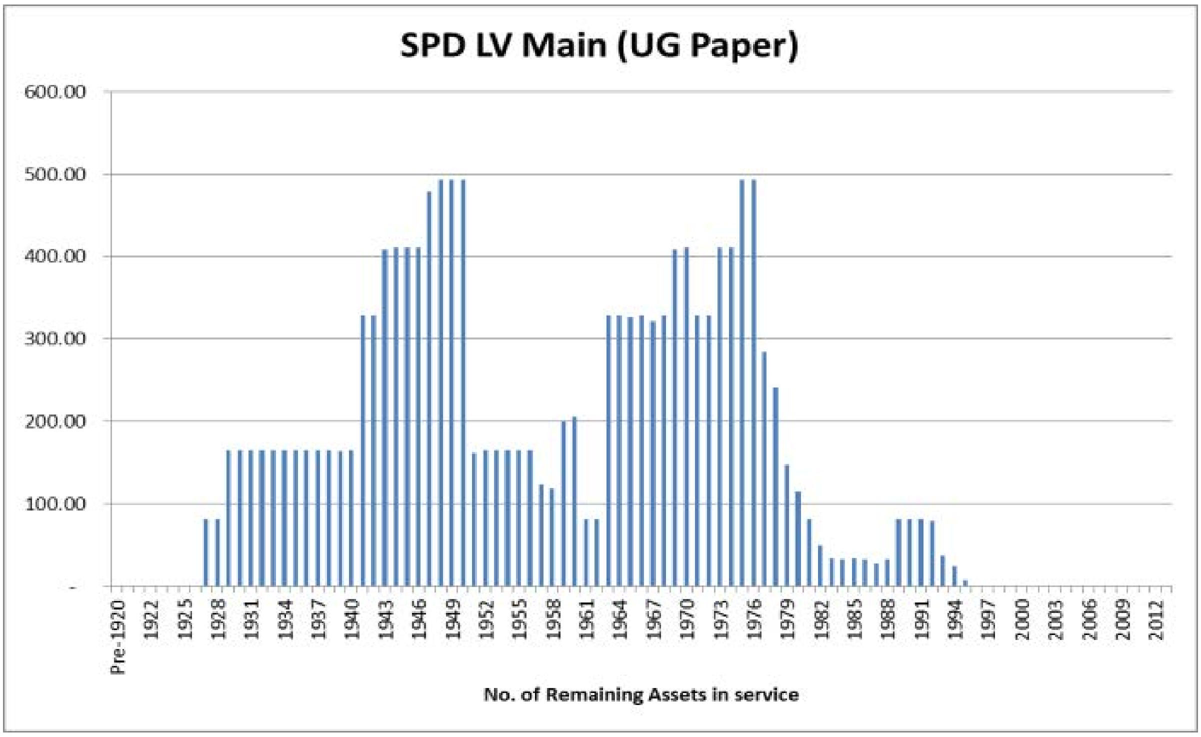
LV Main (UG Consac) (Mean life 59 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	8	12.5%	0	0

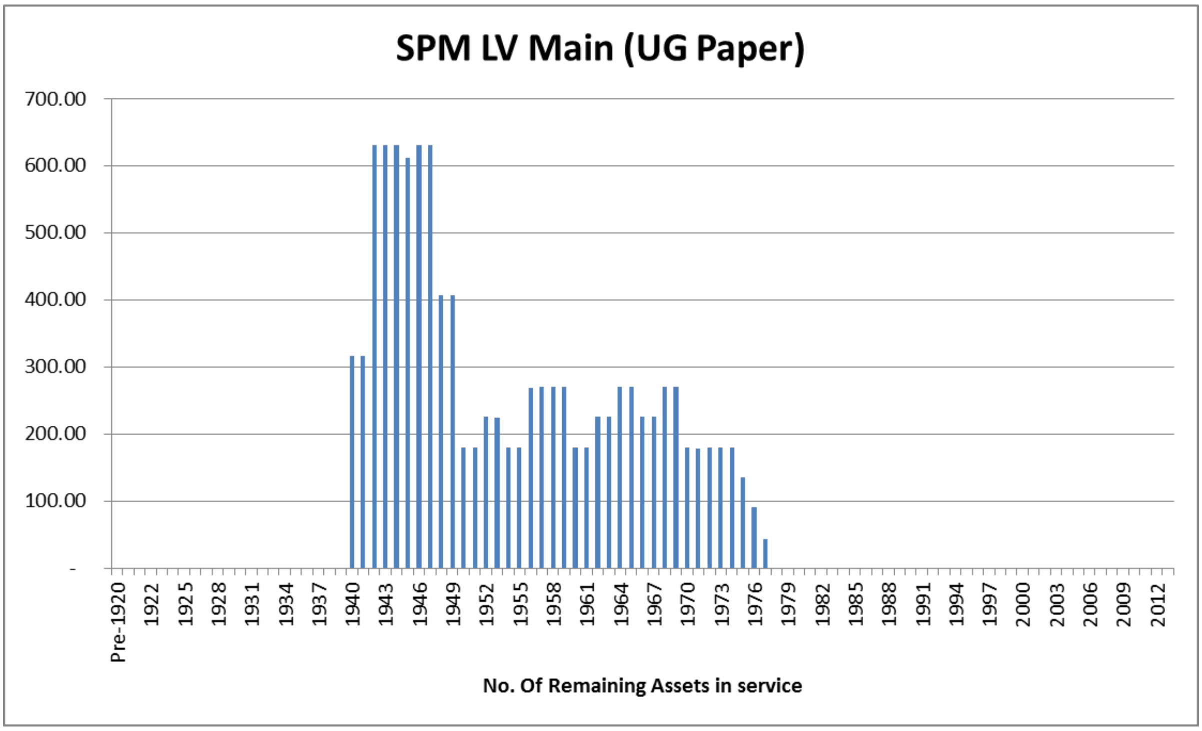
At the end of DPCR5, we will have 8km of Consac cable left in service in SPD, which was installed in the 1970s across the industry and due to poor performance, is being progressively removed. We will remove the remaining 8km of this cable type and replace it with modern plastic insulated cables.

LV Main (UG Paper) (Mean life 101 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	64km	0.05%	0	0
SPM	32km	0.04%	0	0

We have 14,953km of paper insulated cable in service in SPD and 10,988km in SPM. This cable type was installed for many decades as shown in the age profile charts below and has generally been very reliable in operation. We replace this cable type with modern plastic insulated cable only when we experience multiple failures and identify poor condition cable sections.

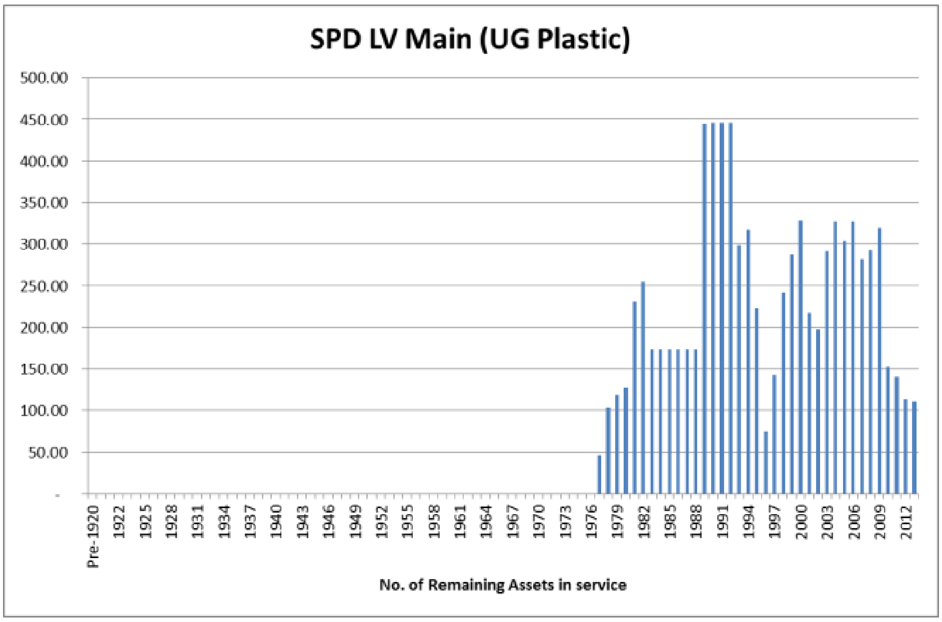
Our age profile graphs indicate the high level of cable volumes installed during the post war period and again during the 1960s until paper technology was replaced by plastic cables.

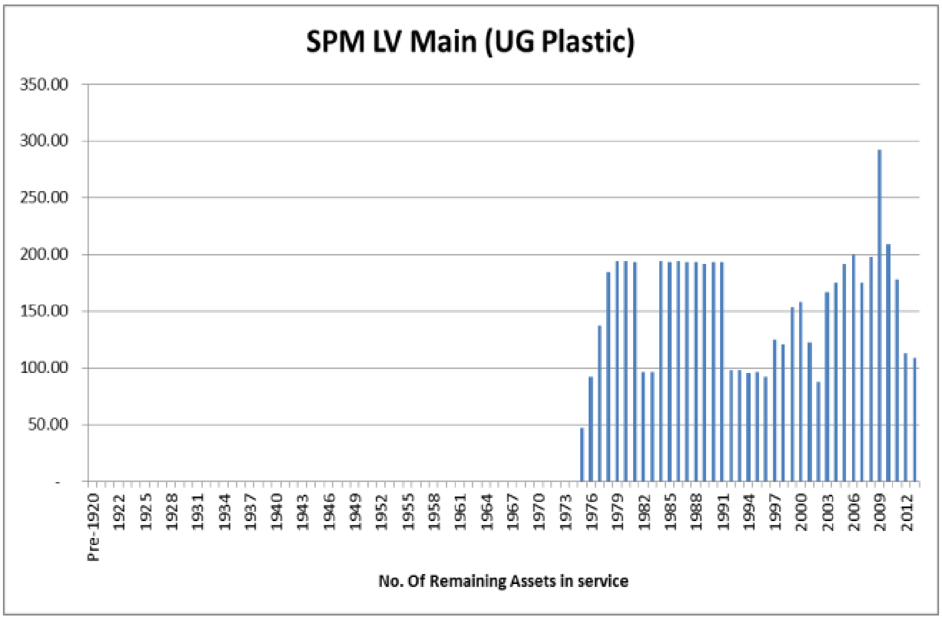

SPD LV Main (UG Paper)
600.00
500.00
400.00
300.00
200.00
100.00
-
Pre-1920
1922
1925
1928
1931
1934
1937
1940
1943
1946
1949
1952
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
2012
No. of Remaining Assets in service


SPM LV Main (UG Paper)
700.00
600.00
500.00
400.00
300.00
200.00
100.00
-
Pre-1920
1922
1925
1928
1931
1934
1937
1940
1943
1946
1949
1952
1955
1958
1961
1964
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
2006
2009
2012
No. Of Remaining Assets in service

LV Main (UG Plastic) (Mean life 101 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	0	0%	109km	8.0
SPM	0	0%	128km	9.5

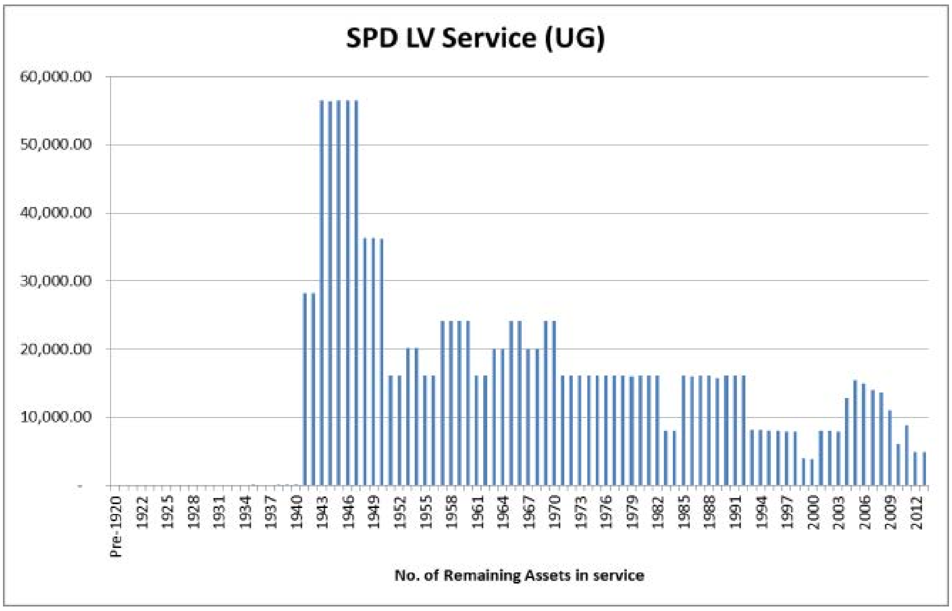
We have 8698km of plastic insulated cable in service in SPD and 6,039km in SPM. This cable type has been installed since the late 1970s as shown in the age profiles below, and operates reliably. When we replace the other LV cable types described above, or underground LV overhead lines described later, we install this type of cable.

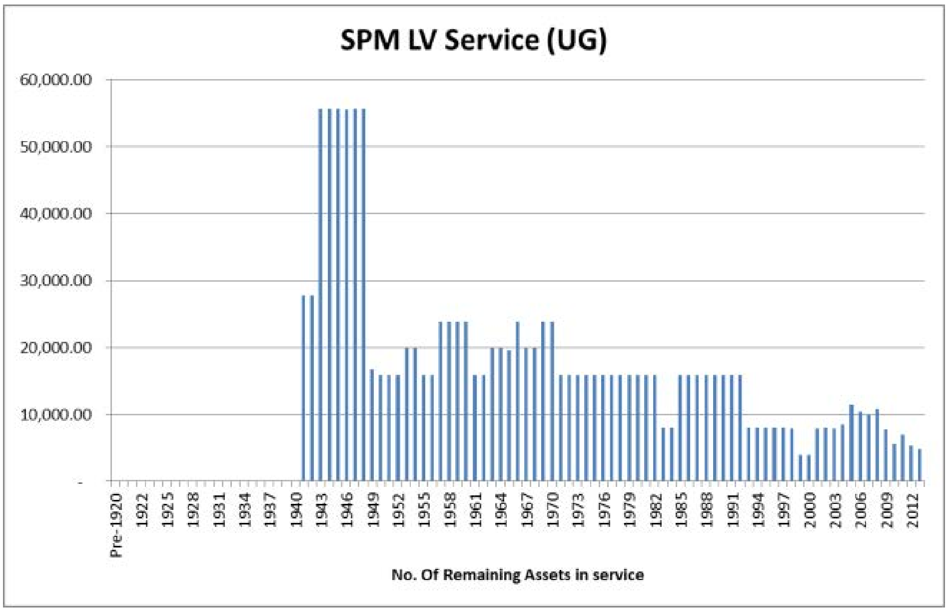




LV Service (UG) (Mean life 99 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	3,200	0.03%	3,200	3.4
SPM	7,192	0.07%	7,192	7.7

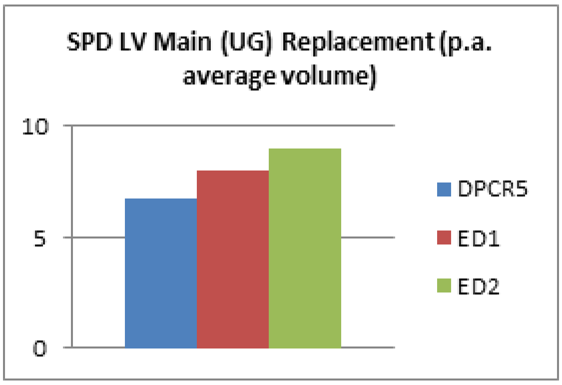
LV service cables connect individual properties to our LV main cables. We have 1,383,204 properties supplied with an underground service in SPD and 1,316,976 in SPM which were installed across the decades, as shown in the age profiles below. When we identify that a service cable is in poor condition, we will replace the service. The volume replaced is a very small percentage of the population.

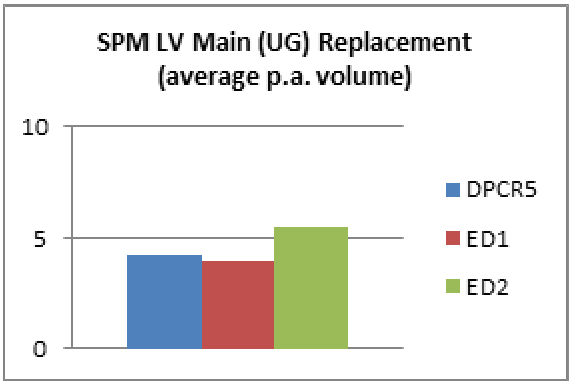




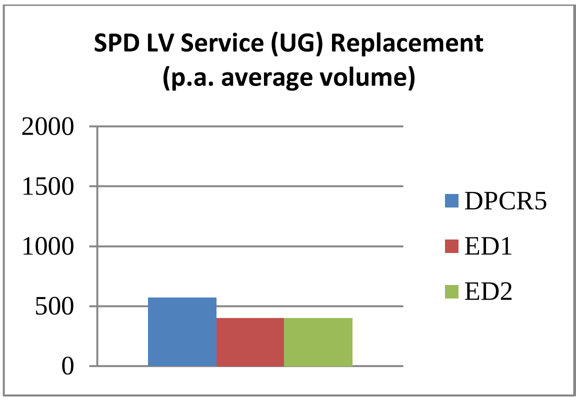
Comparing ED1 to DPCR5

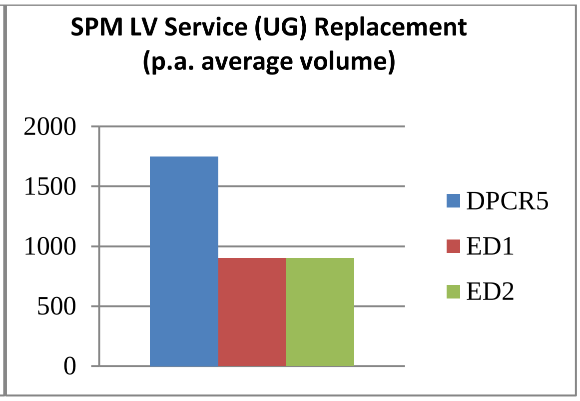
Our replacement plan for LV mains cable from DPCR5 to the end of ED2 is summarised in the charts below. We are forecasting a small upturn in replacement volumes as the cables age. A small proportion of new underground cable associated with our LV overhead line modernisation programme is also included here.





Our replacement plan for LV service cable from DPCR5 to the end of ED2 is summarised in the charts below. Investment in replacing LV underground services is forecast to continue at historic average rates. In the DPCR5 period we have not split service modernisation into overhead line and underground services which results in us showing high volumes in D5 relative to forecast years for LV service (underground) and no volumes for LV service (overhead). This is reflected in a reduction in the per annum spend for LV service (underground) shown in the table below.





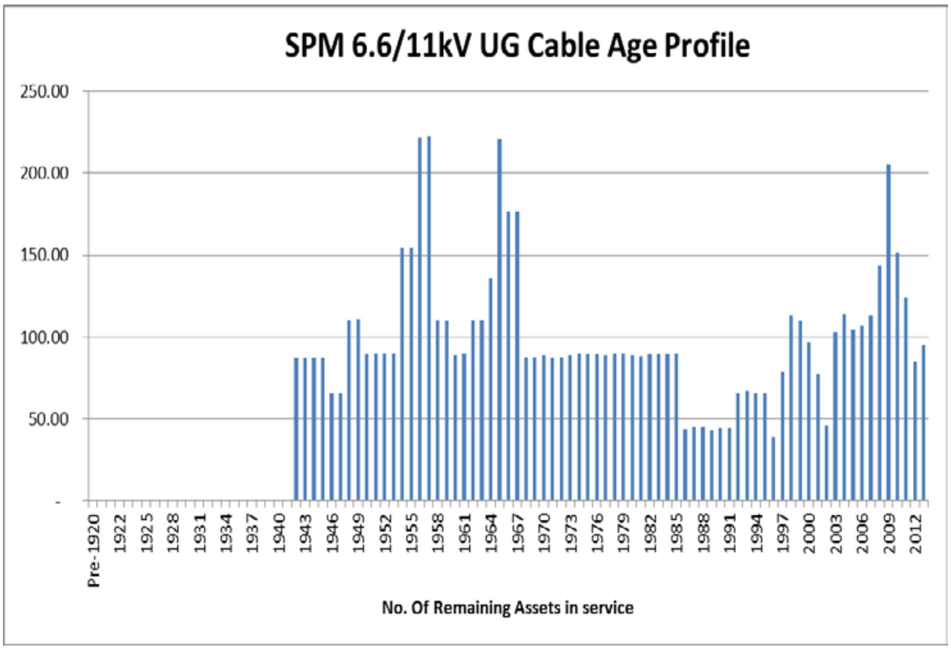
Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
LV Cable	SPD	0.5	2.7	1.0	8.0	88%
	SPM	0.7	3.5	1.2	9.5	70%
LV UG Services	SPD	0.7	3.4	0.4	3.4	-37%
	SPM	1.8	9.2	1.0	7.7	-48%
Total		3.8	18.8	3.6	26.7	-5%

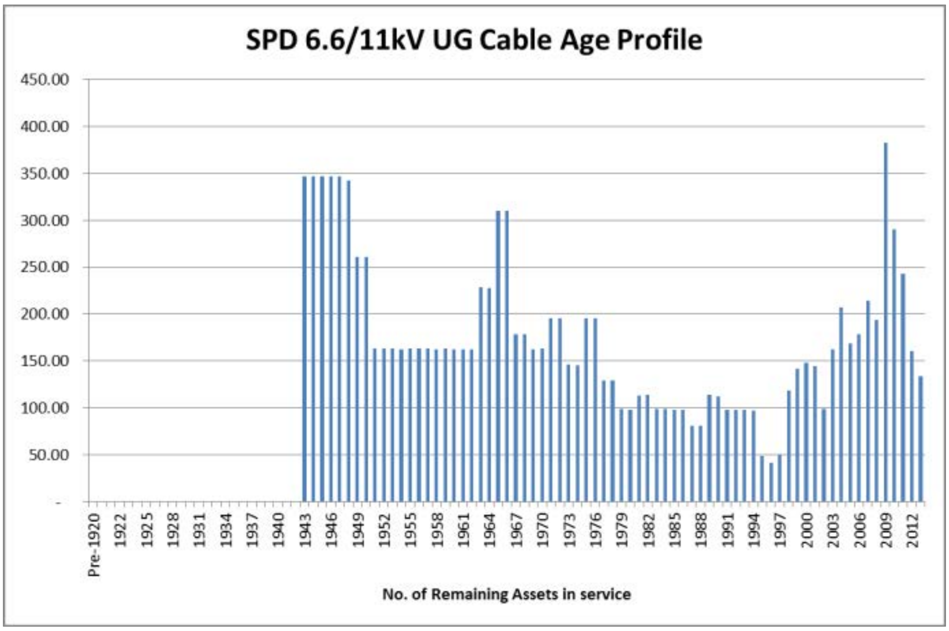
8.3.1.2. HV Underground Cables

Our Plan

6.6/11kV UG Cable				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	96	0.1%	96	10.3
SPM	128	0.2%	128	13.6

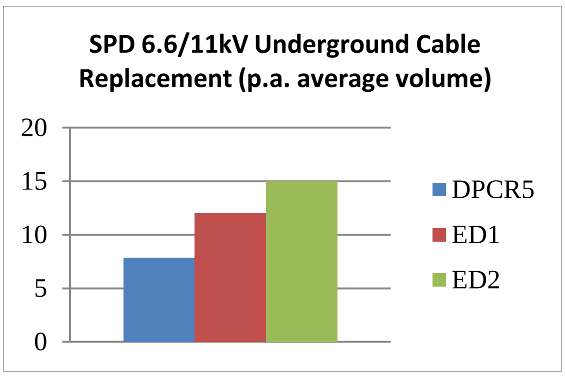
We have 12,361km of HV cable in SPD and 7,180km in SPM, installed across the decades as shown in the age profile below. Through analysis of condition and performance, we have found that around 40% of cable faults occur on 10% of our 11kV cable circuits. Replacement of entire circuits is often costly and through analysis of fault clusters and mapping of historical faults we are able to target replacement of the poorly performing sections of cable to manage overall failure rates near national average.

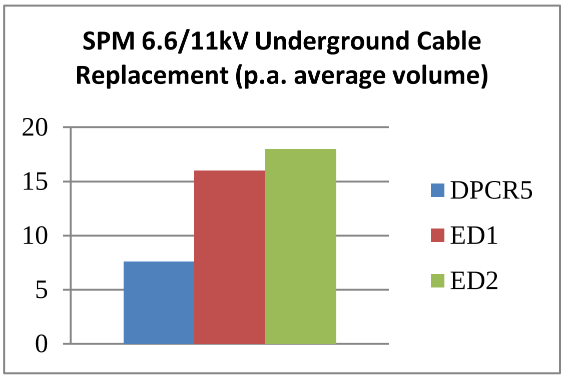




Comparing ED1 to DPCR5

Investment in replacing HV cable increases from historic rates, to maintain our cable fault rate as the average age of our cables increases. Our replacement plan for HV cable from DPCR5 to the end of ED2 is summarised in the charts below.





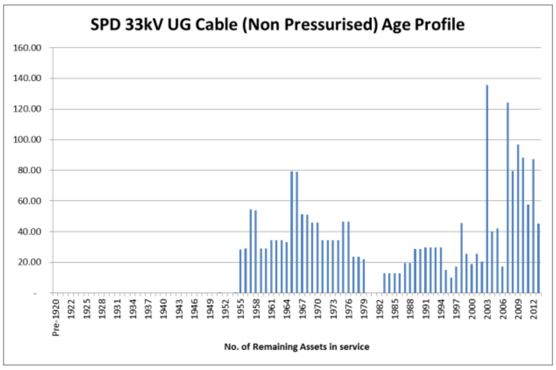
Asset Replacement, Refurbishment		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
11kV Cable	SPD	0.9	4.4	1.3	10.3	45%
	SPM	1.2	6.0	1.7	13.6	43%
Total		2.1	10.4	3.0	23.9	44%

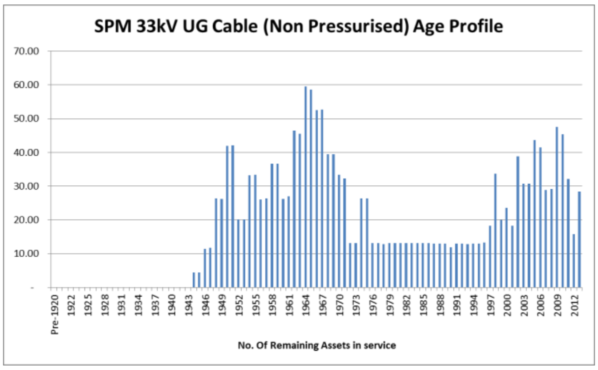
8.3.1.3. 33kV Underground Cables

Our Plan

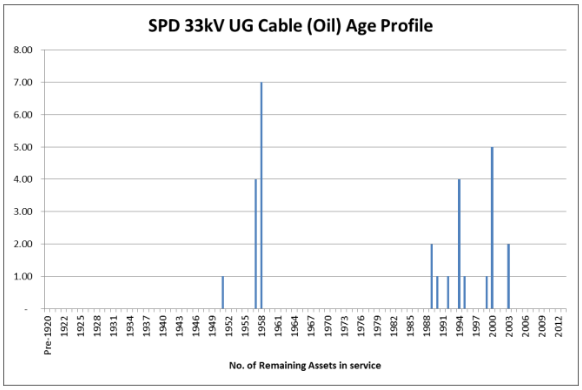
33kV UG Cable (Non Pressurised)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	48	0.2%	48	6.9
SPM	41	0.3%	41	5.8

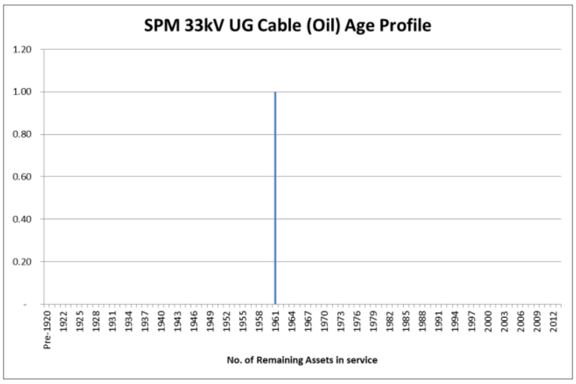
We have 2,276km of non-pressurised 33kV cable installed in SPD and 1,790km in SPM. This type of cable has been widely used across the industry and installed for many years, as shown in the age profiles below. Through analysis of condition and performance of EHV cable we have found that around 40% of cable faults occur on 10% of our 33kV cable circuits. Replacement of entire circuits is often costly and through analysis of fault clusters and mapping of historical faults we are able to target replacement of the poorly performing sections of cable to manage overall failure rates near national average.





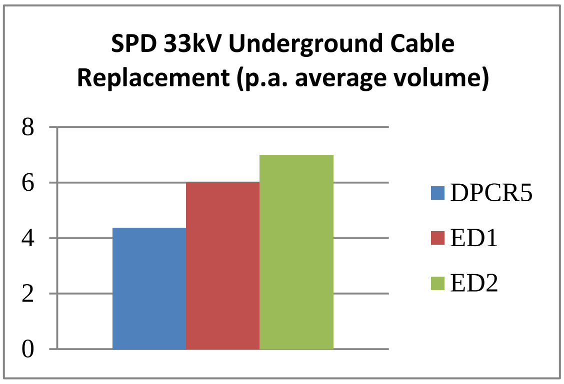
We have 29km of fluid filled 33kV cable installed in SPD and 1km in SPM. This cable is generally reliable and we replace fluid filled cable only where leakage rates justify it or fault history demonstrates poor condition. The 30km of cable is performing well so no replacement of this type of cable is planned for ED1.

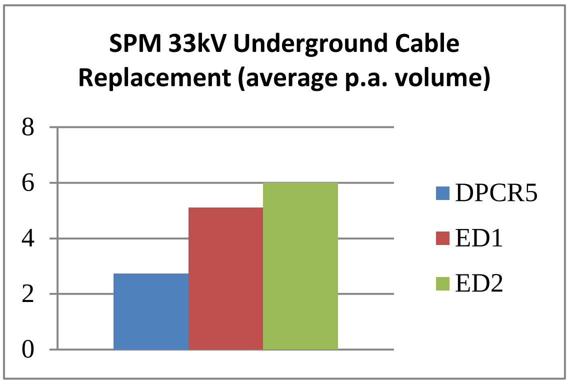




Comparing ED1 to DPCR5

Volumes of cable replacement continue at DPCR5 levels and investment reduces marginally in ED1. Our replacement plan for 33kV cable from DPCR5 to the end of ED2 is summarised in the charts below. We are forecasting a small increase in volumes longer term to address the effects of ageing.





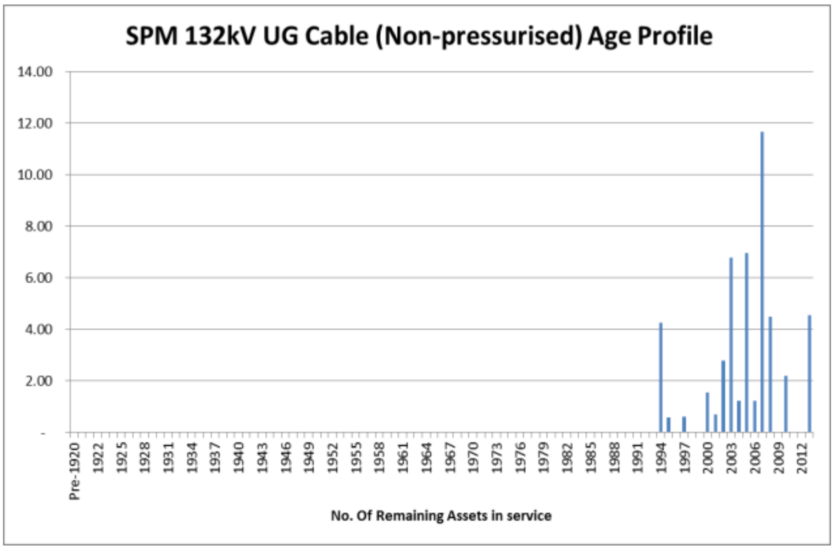
Asset Replacement		DPCR5 D5 pa £m	DPCR5 Total £m	RIIO-ED1 ED1 pa £m	RIIO-ED1 Total £m	% change
33kV Cable	SPD	1.0	4.9	0.9	6.9	-12%
	SPM	0.9	4.4	0.7	5.8	-18%
Total		1.9	9.3	1.6	12.8	-15%

8.3.1.4. 132kV Underground Cables

Our Plan

132kV UG Cable (Non-pressurised) (Mean life 59 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	0	0	19	18.5

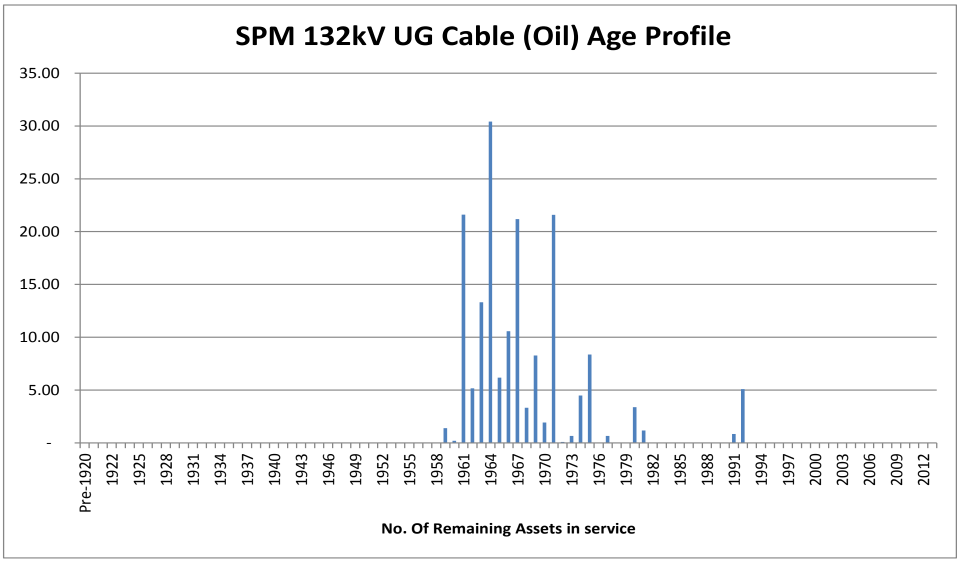
We have 50km of non-pressurised 132kV cable installed in SPM. This cable type has been in service since the 1990s, as shown in the age profile and operates reliably. When we replace other 132kV cable types described below, we will install this type of cable. Within the additions planned for ED1, there is 3km of new cable required as a consequence of 132kV plant replacement. The expenditure for this asset type is shown against the cable type being disposed of.



132kV UG Cable (Oil) (Mean life 61 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	11km	0.8	0	0

We have 170km of fluid filled 132kV cable installed in SPM. This cable type was installed from the 1950s to the early 1990s, as seen in the age profile below, and is generally reliable. We replace fluid filled cable only where leakage rates justify it or fault history demonstrates poor condition.

The Kirkby/Gillmoss/Fazakerley/Bootle circuit (10.8km in length) has an oil leakage rate that is 10 times worse than the average in SPM and accounts for 50% of the total oil leakage from all our 132kV cables and this is the only replacement we have planned for ED1.

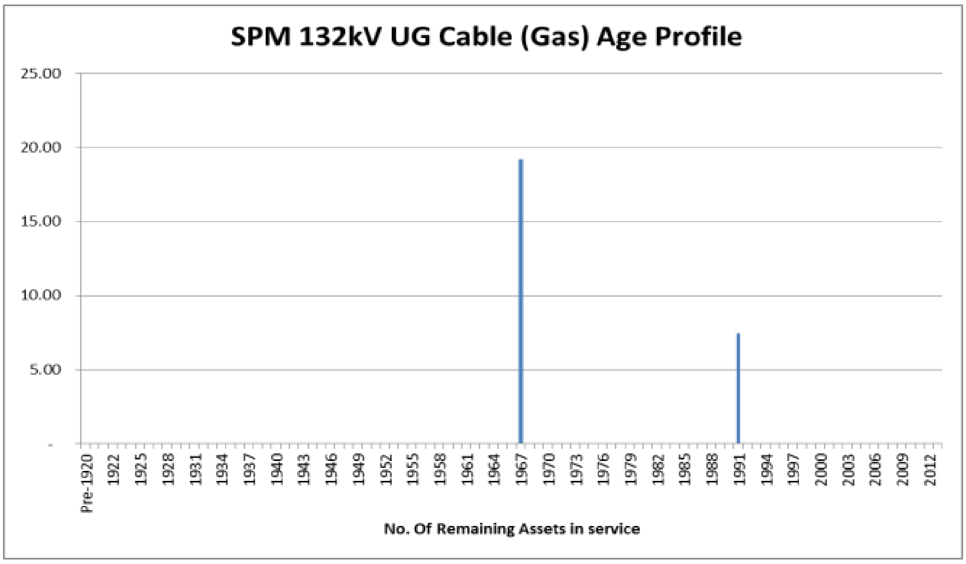


132kV UG Cable (Gas)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (m)
SPM	5	5%	-	0

We have 27km of gas compression 132kV cable installed in SPM. This is split into 19km of British manufactured cable installed in 1967 and 7.5km of German manufactured cable installed in 1991. The British type is extremely unreliable and by ED1 we will have replaced all but one circuit of this type.

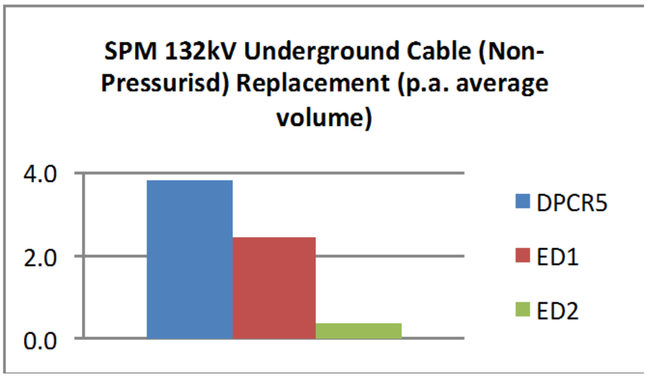
The cable is installed in steel pipes which are pressurised with an inert gas. Damage to the pipeline causes leaks and the pipe to lose pressure, allowing moisture into voids in the cable and making faults much more likely. These cables supply densely populated urban areas and failures compromise network security.

The last 5km of British gas compression cable will be replaced in ED1. The German manufactured cable will continue in service, as it operates reliably.



Comparing ED1 to DPCR5

Our replacement plan for 132kV cable from DPCR5 to the end of ED2 is summarised in the chart below. Overall the annual spend on 132kV cable reduces from DPCR5 levels and our long term forecast assumes that the three short sections of fluid filled cable that are currently Health Index 4 are replaced.



Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV Cable	SPM	3.8	18.8	2.3	18.6	-39%
Total	SPEN	3.8	18.8	2.3	18.6	-39%

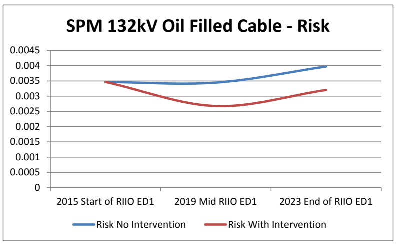
Asset Health and Criticality Indices

132kV cable is covered by our health and criticality assessment processes. The tables below show the net change in health and criticality indices as a result of our planned interventions in ED1, along with the associated asset risk profiles over the period.

Applying criticality to our HI outputs provides a measure of network risk. The risk profiles for 132kV cable are also shown for the ED1period, both with and without planned intervention.

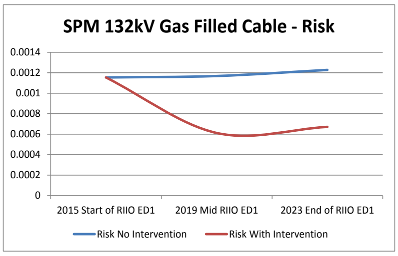
132kV Oil Filled Cable – Net HI and CI Movements.

	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	0	0	0	0	0	0
CI2	0	0	0	0	-8.27831	-8.27831
CI3	0	0	0	0	0	0
CI4	0	0	0	0	-2.62169	-2.62169
Total HI	0	0	0	0	-10.9	-10.9



132kV Gas Filled Cable – Net HI and CI Movements

SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	0	0	0	0	0	0
CI2	0	0	0	0	-5	-5
CI3	0	0	0	0	0	0
CI4	0	0	0	0	0	0
Total HI	0	0	0	0	-5	-5



8.3.1.5. Rising and Lateral Mains

Rising and Lateral mains are the cables within buildings which supply multiple properties.   A substantial amount of these cables were installed many years ago and are now in poor condition. In DPCR5, we established a pioneering programme to replace ageing electrical cables in flatted properties including high rises and tenements and are forecasting that we will have modernised services to 90,000 customers by March 2015. In ED1, we plan to carry out work at a further 300,000 properties.

Our Plan

Rising Mains		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Rising Mains	SPD	10.7	53.7	10.1	81.1	-6%
	SPM	4.2	21.0	4.9	39.0	16%
Total		14.9	74.7	15.0	120.1	0%

The Rising and Lateral Mains (RLM) modernisation programme has been developed within the DPCR5 period and is specifically targeted at an ageing legacy asset installed within multi-occupied properties in both licence areas. During the development of our DPCR5 plan, questions relating to legal ownership of, and responsibility to maintain, these assets were addressed, with funding being agreed to target the highest risk property types. Legal advice sought by us at the time concluded that RLM systems form part of the distribution system and the operation and use of Internal Mains by SPD and SPM are activities that are subject to obligations on us under the Electricity Act 1989 (the 1989 Act), the Distribution Licence and the Electricity, Safety, Quality and Continuity Regulations (ESQCR).

As a result of this confirmation of responsibility, we commenced a RLM modernisation programme in the SPM and SPD network areas. Our ED1 submission incorporates the continuation of our established programme, reducing the public safety risk associated with equipment situated in all areas of the customers' properties.

The relative size of these programmes differs between our licences significantly due to the higher proportion of properties in the SPD network area served by RLMs.

The risks associated with internal mains are the causation of fire and smoke within high occupancy buildings with constrained points of access and egress. We have actively engaged with relevant stakeholders during the DPCR5 regulatory period, including Local Authorities, Industry Forums (SELECT) and the Health and Safety Executive (HSE), receiving considerable support.

Moving into RIIO-ED1, the focus of the modernisation programme will shift from multi-storey tower blocks to tenements, flats and houses as the next highest risk property groups. Programme delivery in terms of customer numbers is expected to increase as the cable lengths associated with flats decrease. Similarly we expect the level of engineering works and labour requirements per property to reduce during RIIO-ED1. Our expectation is to complete all tower block modernisation works by the end of DPCR5.

For further information on Rising Mains please refer to our ANNEX C6 - Rising Mains & Laterals Strategy - SPEN.

8.3.2. Overhead Lines

SPD and SPM use overhead lines at 132kV (SPM only), 33kV, 11kV and LV to distribute energy to 3.5 million customers in our licence areas. Our plans for these assets are summarised by voltage and by construction type.

By the end of DPCR5 on our strategically important 132kV overhead lines, we will have replaced 139 circuit km of conductor, with work in progress to complete a further 28km, equating to 34km per annum. In RIIO ED1 we plan to replace 412 circuit km of conductor equating to 51.5 km per annum, and in RIIO ED2 we expect to replace a further 243km of conductor. This peak in ED1 reflects the age profile of our conductors taking account of optimum economic replacement.

Our long term strategies for our EHV and HV overhead line network focuses on making 40% of our interconnected main lines resilient to severe weather events by 2034, managing the deterioration of our assets, maintaining safety and improving the reliability and availability of supply to our customers.

In other locations, lines are considered for replacement or modernisation based on condition. Where a line is replaced, it may be appropriate to install a larger size of conductor providing environmental benefits through the reduction of electrical losses. This also accommodates demand growth including the uptake of Low Carbon Technologies.

Our investment plan for the wood pole overhead line network during RIIO ED1 incorporates:

- *Rebuild of targeted HV and EHV main lines to a storm resilient, 'fit for purpose' specification*
- *Refurbishment of HV and EHV lines on a rolling 12 year cycle to improve performance and manage condition*
- *Modernisation of end of life LV networks in rural villages*

In setting out our plan, we have broken these activities down into the component parts that are used as volume categories within the regulatory reporting framework:

- *Conductor (the wires)*
- *Poles (wooden, metal or concrete) or steel towers*
- *Fittings (steelwork, insulators, stays and anti-climbing devices)*
- *Foundations – concrete at the base of towers*

When we replace a conductor, pole, tower or set of tower fittings we record this as a replacement activity. If we only replace the fittings on a pole, sections of tower steelwork or refurbish concrete foundations then the activity is recorded as refurbishment.

Due to the small population and condition of 33kV towers in SPD, we plan to refurbish all during ED1. Our budget includes all conductor replacement and tower painting, together with some foundation refurbishment and replacement of fittings, according to condition.

For further information on OHL please refer to ANNEXES C6 – LV OHL and ESQCR Strategy - SPEN, C6 - 33kV and 11kV OHL Strategy - SPEN and C6 – 132kV Overhead Lines Strategy - SPEN.

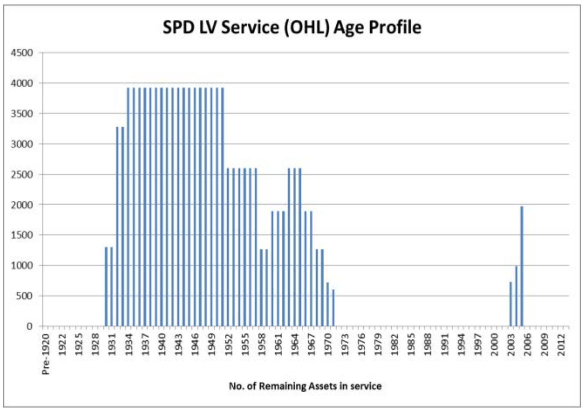
8.3.2.1. LV Service (Overhead)

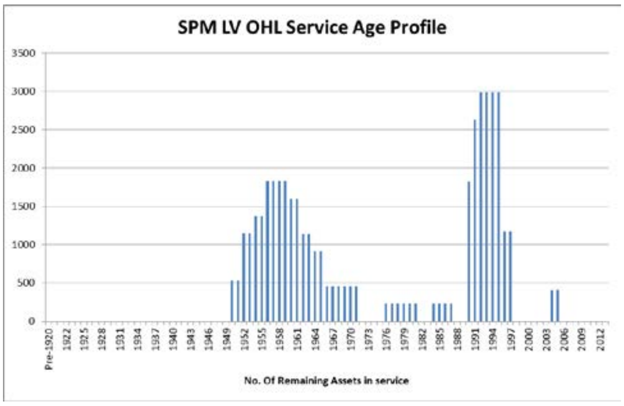
Our Plan

LV Service (OHL) (Mean life 70 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	2,400	0.7%	2,400	2.8
SPM	4,000	0.4%	4,000	4.7

Overhead line services connect individual properties to the LV network. We have 122,772 properties supplied with an overhead service in SPD and 45,484 in SPM. When we identify that a service is in poor condition we will replace it. The volume replaced is a very small percentage of the population.

Our age profile graphs indicate the high level of activity of investment during the throughout 1930s until the early 1970s in SPD, and during the post war period until the 1970s, then again in the 1990s for SPM.





8.3.2.2. LV, HV, 33kV and 132kV OHL Poles

Our Plan

LV, HV, 33kv and 132kV Poles Replacement (mean life 60 years)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	44,040	2%	43,144	61.2
SPM	49,347	2%	47,662	67.7

LV, HV, 33kV Pole refurbishment			
Licence	Average Population Refurbished (% per annum)	RIIO ED 1 Assets Refurbished	RIIO ED 1 Expenditure (£m)
SPD	3%	63,136	24.2
SPM	3%	58,512	22.7

We have 288,177 poles in SPD and 316,950 in SPM. Wooden poles which support our overhead line conductors are treated with creosote to prevent the wood deteriorating but over time, like any wooden structure, they begin to rot. We inspect our poles regularly to assess their condition and suitability for purpose and replace them for the following reasons:

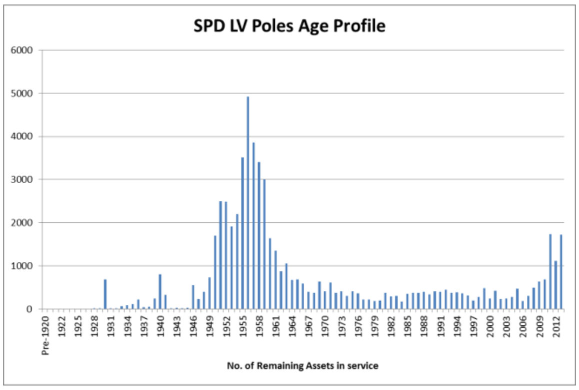
- *Condition has deteriorated and the pole is a Health Index 5*
- *The height of the pole is not adequate to achieve statutory clearance as required by ESQCR*
- *The overhead line is not adequately robust for the weather conditions it is expected to withstand*

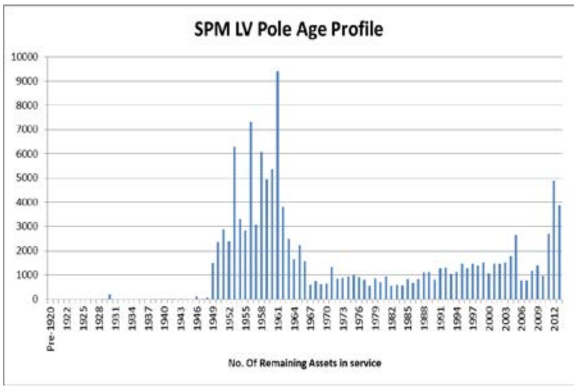
To maximise life, it is sometimes possible to treat a wooden pole with Boron which extends the life of the pole for around 10 years.

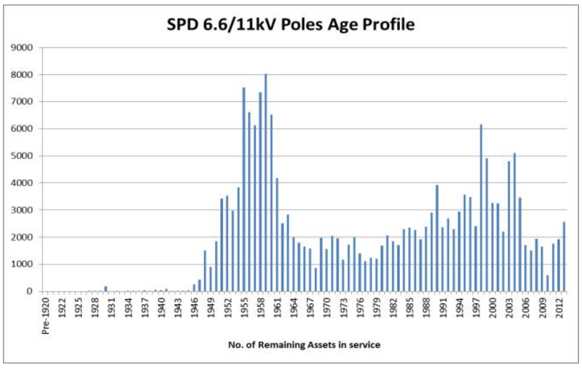
When poles are replaced, the fittings at the top of the pole are also replaced and this is included in the cost of the pole replacement. We also replace poor condition fittings on poles that do not need replacing and in this case we include the costs in our pole refurbishment plans.

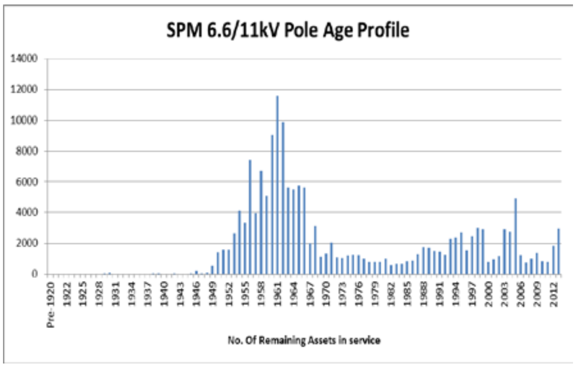
We also have narrow based 33kV steel towers which are now in poor condition and will be replaced with pole lines.

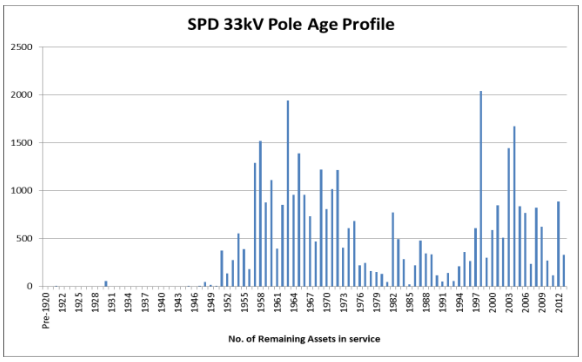
Our age profile graphs indicate the high level of pole installation during the 1940s and 50s associated with rural electrification:

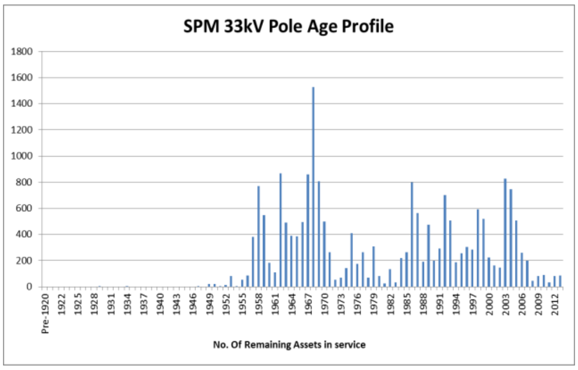






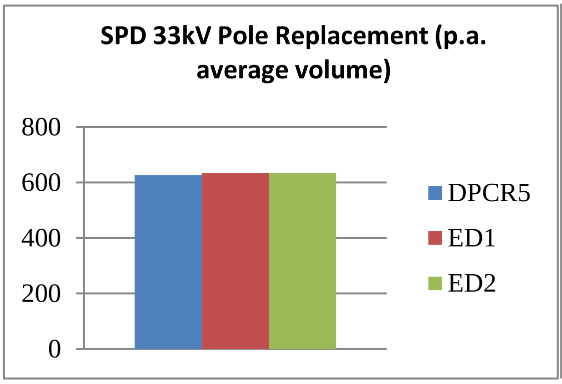


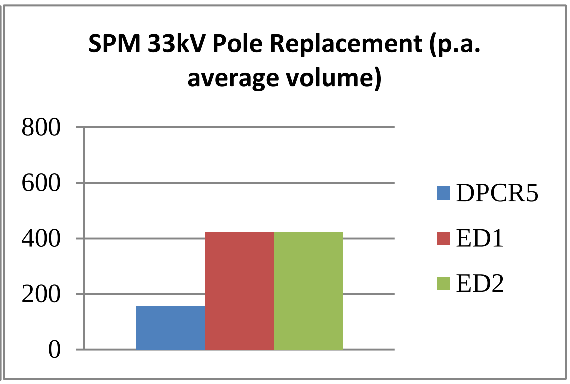


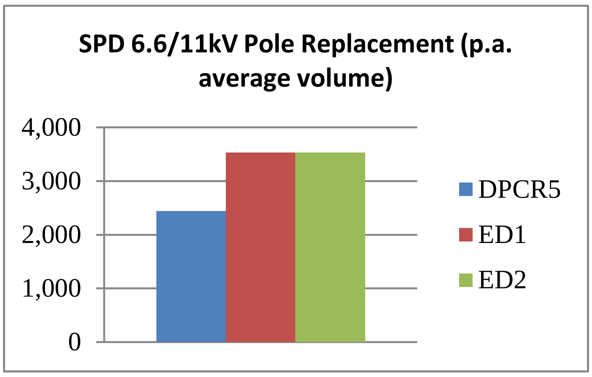


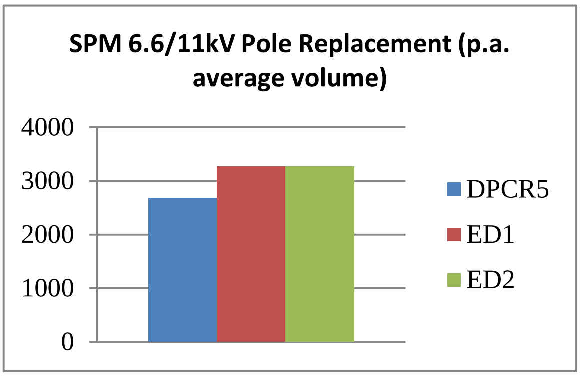
Comparing ED1 to DPCR5

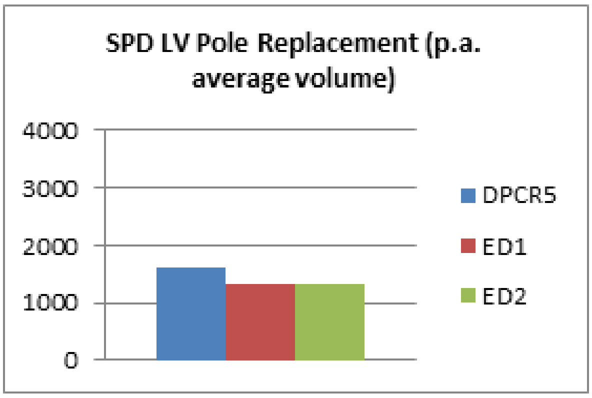
Our replacement plan for poles from DPCR5 to the end of ED2 is summarised in the charts below. Within DPCR5, we have replaced a significant amount of LV poles through our village modernisation and low ground clearance programmes. Given the public safety implications, we prioritised removal of low clearances over rebuild during the early part of DPCRs but are now increasing our rebuild volumes in the final years to levels that will continue through ED1 and beyond to deliver resilience improvement.

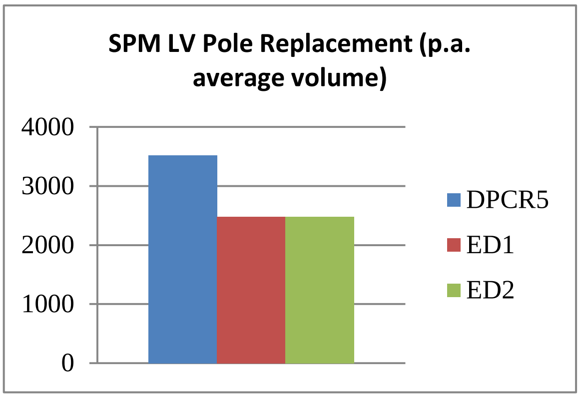












Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV Pole Replacement	SPM	0.0	0.0	0.7	5.4	N/A
33kV Pole Replacement	SPD	1.0	5.2	1.1	8.6	3%
	SPM	0.2	1.2	0.7	5.7	195%
11kV Pole Replacement	SPD	3.7	18.6	5.5	43.8	47%
	SPM	4.1	20.7	5.1	40.4	22%
LV Pole Replacement	SPD	1.1	5.5	1.1	8.9	0%
	SPM	2.7	13.3	2.0	16.1	-24%
Total	SPEN	12.9	64.6	16.1	128.9	25%

Asset Health and Criticality Indices

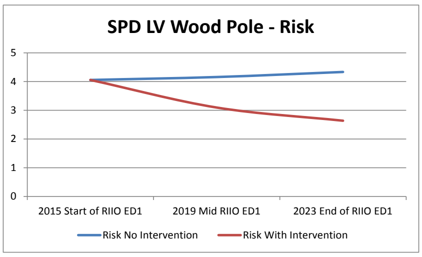
Health and Criticality Indices are captured for wood pole assets. The majority of our pole replacements move the health index from HI5 to HI1. However, some pole replacements can result in movements across other Health Index categories as rebuilding overhead lines for resilience involves replacement of all poles on the circuit regardless of health index. The impact of our plans is shown in the risk matrix below. The health index movements also include the impact of ESQCR interventions.

Applying criticality to our HI outputs provides a measure of network risk. Our overall network risk across all asset categories at the end of ED1 is consistent with that at the start of ED1. The relative risk measures for poles with and without investment are shown below.

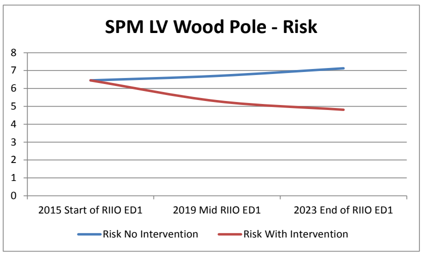
LV Poles

There are fewer poles added than removed due to the small percentage of LV OHL that is replaced with underground cable, equating to 896 in SPD and 1928 in SPM.

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	7749	-1004	-1043	-971	-5042	-311
CI2	11561	-1560	-1526	-1317	-7622	-464
CI3	1505	-159	-158	-135	-1114	-61
CI4	1481	-173	-170	-152	-1046	-60
Total HI	22296	-2896	-2897	-2575	-14824	-896

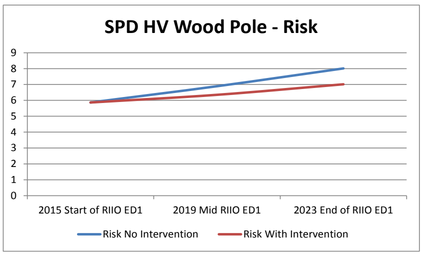


SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	15730	-2439	-2420	-2230	-9543	-902
CI2	12514	-2050	-2077	-1823	-7282	-718
CI3	2974	-464	-469	-383	-1828	-170
CI4	2408	-397	-384	-320	-1445	-138
Total HI	33626	-5350	-5350	-4756	-20098	-1928

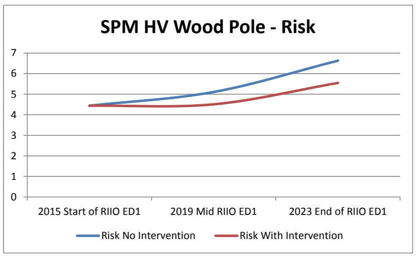


HV Poles

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	2134	-689	-620	-381	-444	0
CI2	25562	-7071	-7111	-6772	-4608	0
CI3	2590	-653	-689	-709	-539	0
CI4	191	-59	-52	-45	-35	0
Total HI	30477	-8472	-8472	-7907	-5626	0

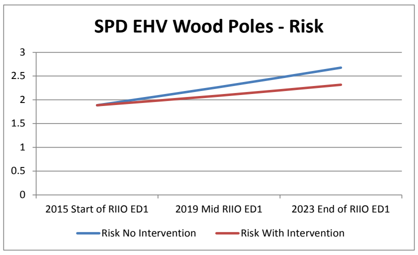


SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	0	0	0	0	0	0
CI2	27889	-7318	-7355	-6863	-6353	0
CI3	1842	-503	-469	-430	-440	0
CI4	83	-20	-17	-25	-21	0
Total HI	29814	-7841	-7841	-7318	-6814	0

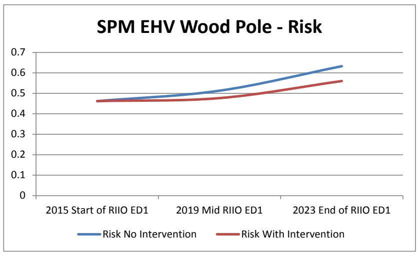


33kV Poles

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	1324	-460	-434	-285	-145	0
CI2	2743	-808	-833	-895	-207	0
CI3	852	-254	-243	-203	-152	0
CI4	52	0	-12	-37	-3	0
Total HI	4971	-1522	-1522	-1420	-507	0



SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	675	-189	-194	-218	-74	0
CI2	2103	-641	-650	-590	-222	0
CI3	531	-188	-171	-130	-42	0
CI4	20	-1	-4	-13	-2	0
Total HI	3329	-1019	-1019	-951	-340	0



8.3.2.3. LV Main OHL Conductor

Our Plan

LV Main (OHL) Conductor				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	505	2%	460	10.0
SPM	1,060	2%	964	20.9

Much of our LV overhead line network was originally installed during electrification in the 1940s and 1950s. In our SPD licence area, we have 3,067km of main lines at LV with almost double the amount in SPM at 6,601km. Generally, this difference is due to historic construction policies, with underground installations being more common in SPD.

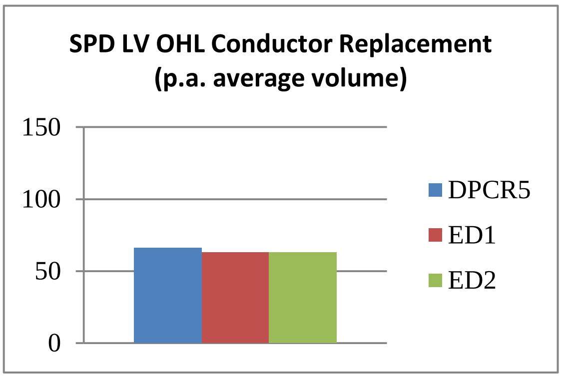
The vast majority of our LV overhead line network is constructed to an open wire design. Some conductors were fabric and/or rubber insulated but this has deteriorated (for example, due to exposure to daylight/UV) and cannot be relied upon for safety and is also prone to damage from trees and windborne debris.

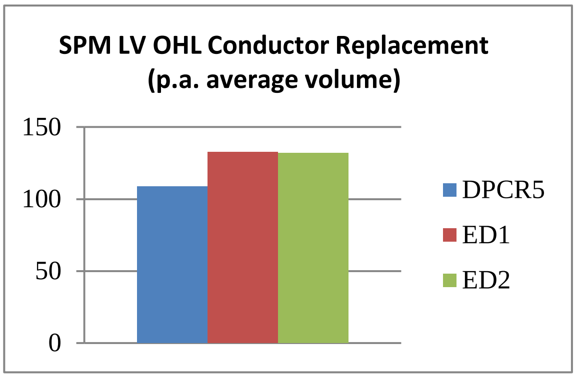
ABC (Aerial Bundled Conductor) is now our standard installation for new and modernised LV overhead lines, as the wires are fully insulated making it a safer and more weather resilient option.

Due to physical restrictions and the visual improvement offered, in about 8% of cases, we remove the OHL in villages and replace it with underground cables. This is not feasible everywhere because of the cost but does provide performance benefits for some rural customers.

Comparing ED1 to DPCR5

Investment in replacing LV OHL main conductor and poles continues at a broadly consistent rate of 2% per annum. Our replacement plan for LV Main OHL conductor from DPCR5 to the end of ED2 is summarised in the charts below.





Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
LV Pole Line Conductor Replacement	SPD	1.2	6.2	1.3	10.0	2%
	SPM	2.6	12.9	2.6	20.9	1%
Total	SPEN	3.8	19.1	3.9	30.9	1%

Cost Benefit Analysis

We have considered a number of options for replacement or undergrounding of LV OHL and the summary outcome is shown below. Further detail is provided in ANNEX C6 – Cost Benefit Analysis, reference 12 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Baseline- Overhead line with 8% UG	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
2	Overhead line - Increased conductor size for Future Load	Rejected	Rejected due to negative NPV	-£1.16	-£1.48	-£1.69	-£1.91
3	Underground Cable (185 waveform)	Rejected	Rejected due to negative NPV	-£67.73	-£86.53	-£98.66	-£109.59
4	Underground - Combination of Increased conductor size and U/G cable	Rejected	Rejected due to negative NPV	-£13.77	-£17.59	-£20.06	-£22.31

8.3.2.4. HV Main OHL Conductor

Our Plan

6.6/11kV OHL (Conventional Conductor)				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	1,521	1%	1,521	29.6
SPM	1,414	1%	1,414	27.4

In SPD, we have 13,691km of main lines at HV and 12,218kM in SPM. HV conductor is generally reliable and will remain in service for many years. We replace conductor when we rebuild a circuit which was not originally designed and built to an adequate resilient specification.

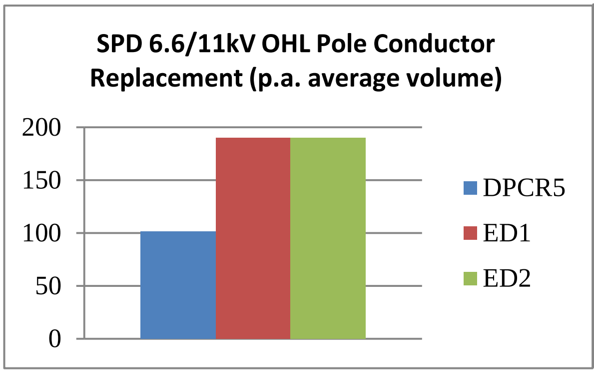
New lines will be built according to our current construction standard. In a severe weather area, this specification requires the installation of 100mm² AAAC 119-AL3 conductor, code name “Oak”, as a minimum and where it is being installed in a normal weather area the requirement is to install 50mm² AAAC 60-AL3 conductor, code name “Hazel”.

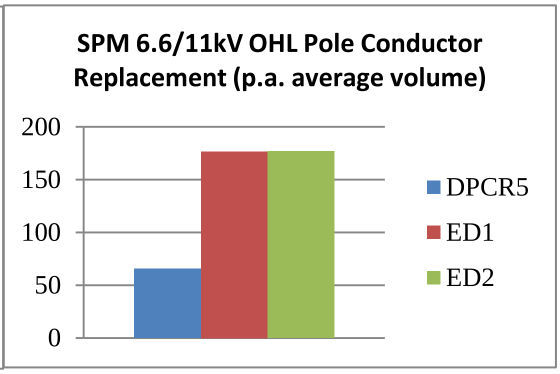
Our cost benefit analysis has shown that employing “Oak” conductor for all main line rebuilds is the most cost effective solution. In addition to the lower lifetime costs, the upgraded lines will benefit from greater storm resilience, providing our customers in these areas with enhanced reliability. The enhanced current carrying capacity also reduces network losses and can assist in meeting future load increases arising from the uptake of low carbon technology.

We have a small population of particularly poorly performing and non-standard conductors. Removing these conductors, of which we have 153km in SPD and 150km in SPM, will provide more reliable supplies to rural customers.

Comparing ED1 to DPCR5

Our replacement plan for HV OHL conductor from DPCR5 to the end of ED2 is summarised in the charts below. Our long term strategy for storm resilience will require consistent investment into ED2.





Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
11kV Pole Line Conductor Replacement	SPD	3.4	16.8	3.7	29.6	10%
	SPM	2.3	11.3	3.4	27.4	51%
Total	SPEN	5.6	28.2	7.1	57.1	27%

Cost Benefit Analysis

We have considered a number of options for achieving storm resilient HV OHL and the summary outcome is shown below. Further detail is provided in the ANNEX C6 – Cost Benefit Analysis, reference 50 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected	Rejected due to negative NPV	-£0.20	-£0.47	-£0.90	-£1.61
2	Refurbish the overhead line only	Rejected	Rejected due to negative NPV	-£0.93	-£1.90	-£2.94	-£4.56
3	Underground the overhead line	Rejected	Rejected due to negative NPV	-£2.94	-£3.30	-£3.47	-£3.50

8.3.2.5. 33kV and 132kV OHL Pole Line Conductor

Our Plan

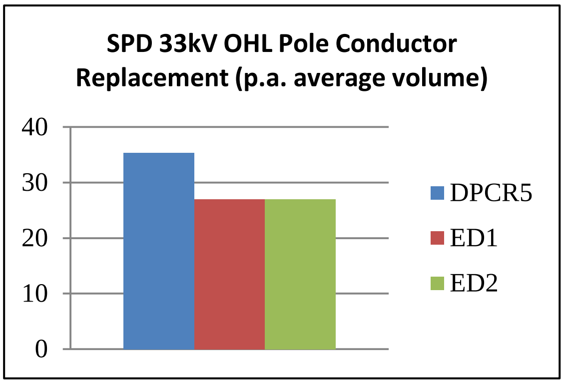
33kV and 132kV OHL (Pole Line) Conductor				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	216	1%	216	5.5
SPM	152	1%	194	9.9

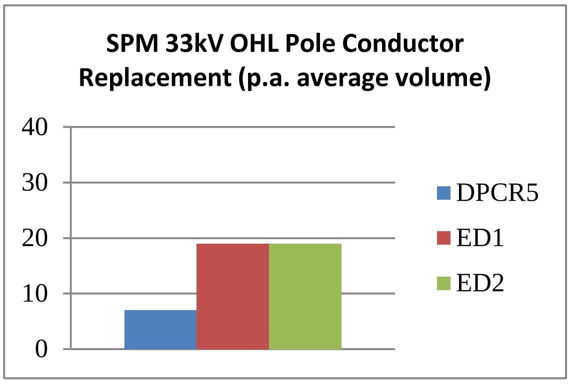
33kV and 132kV conductor on wood pole lines are generally reliable and will remain in service for many years. We replace conductor when we rebuild a circuit which was not originally designed and built to an adequate resilient specification or when the condition of the conductor has deteriorated.

We have no existing 132kV pole lines that require investment in the ED1 period but we will be rebuilding a poor condition 132kV steel tower line as a pole line adding 44km of 132kV pole line as a result.

Comparing ED1 to DPCR5

Our replacement plan for 33kV OHL conductor from DPCR5 to the end of ED2 is summarised in the charts below. In our SPM area, we have experienced difficulties in achieving wayleaves to rebuild some of our 33kV overhead lines which has resulted in a low delivery of volumes for much of DPCR5. Our forecast continues in line with our long-term plan to rebuild to resilient specifications.





Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV & 33kV Pole Line Replacement	SPD	1.8	9.2	0.7	5.5	-63%
	SPM	1.2	6.0	1.2	9.9	3%
Total	SPEN	3.1	15.3	1.9	15.4	-37%

Cost Benefit Analysis

We have considered a number of options for achieving storm resilient 33kV wood pole OHL and the summary outcome is shown below. Further detail is provided in the ANNEX C6 – Cost Benefit Analysis, reference 61 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Baseline scenario: Rebuild overhead line to new storm resilient specification and cut trees to ETR132 methodology	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	Rebuild overhead line to new specification but do not cut trees to ETR132	Rejected	Rejected due to negative NPV	-£0.09	-£0.22	-£0.49	-£0.94
2	Refurbish the overhead line only	Rejected	Rejected due to negative NPV	£0.04	-£0.61	-£1.48	-£2.85
3	Underground the overhead line	Rejected	Rejected due to negative NPV	-£5.44	-£6.29	-£6.78	-£7.12

8.3.2.6. 33kV and 132kV Overhead Tower Line Conductor

Our Plan

33kV and 132kV OHL (Tower line) Conductor				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	160	12.5%	160	3.8
SPM	516	5%	472	32.4

Aluminium conductor with galvanised steel reinforced core (ACSR) has been utilised on 33kV and 132kV high voltage overhead lines for over 80 years. The design of this type of conductor, with its differing metallic elements, is susceptible to galvanic corrosion between the strands which is heavily influenced by the weather and pollutants in the atmosphere (attacking the galvanising on the steel core).

The 132kV distribution overhead network was constructed from the 1930s through to the 1970s using “Lynx” 175 sq mm ACSR phase conductor, with the bulk of it being constructed in the 1950s & 60s. ACSR conductor is generally expected to have a mean asset life of around 54 years and therefore the remaining population of our original conductor is at or approaching end of life (Asset Health 4 or 5).

To address this ageing concern, we have rebuilt 40% of the 132kV overhead line network in the last 20 years. However the age profile of the conductors is such that we need to increase the rate of replacement in ED1.

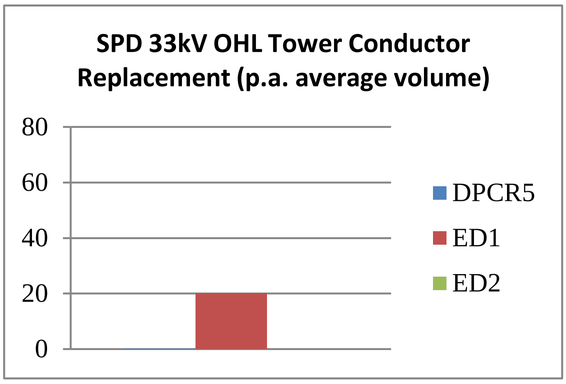
Inspections show that there is no imminent risk of conductor failure in the short term under normal operating conditions. However as shown in our health index analysis, by 2023, based on our technical assumptions for degradation and the age of the conductor, there is a significant medium risk of conductor failure which we need to address.

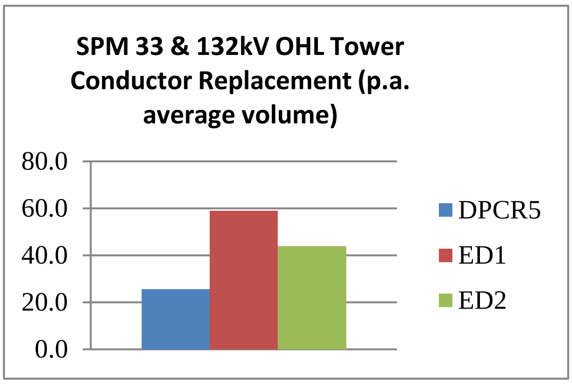
The method of replacement and the associated costs of doing so depend on the residual strength of the conductor, which degrades over time. If a conductor is badly corroded (i.e. the residual strength of the steel core cannot be assured) the only re-conductoring option available may involve lowering the conductor to ground level. The cost of having to do this can be up to 2.5 times more expensive than utilising ‘tension stringing’ or ‘catenary block’ techniques, which require confidence in the residual strength of the conductor being removed.

We therefore consider that the most economic time to replace conductor is before it degrades to a point where tension stringing can no longer be achieved.

Comparing ED1 to DPCR5

Our replacement plan for 33kV and 132kV OHL tower conductor from DPCR5 to the end of ED2 is summarised in the charts below. In both our licence areas, our historic investment in 33kV tower line conductor has been modest and is now forecast to increase through the RIIO-ED1 period. In SPM, 132kV tower line conductor investment will increase to replace Health Index 5 conductor and continue into ED2 to complete replacement. More detail on our investment plans for 132kV steel towers can be found in ANNEX C6 – 132kV Overhead Lines Strategy - SPEN.



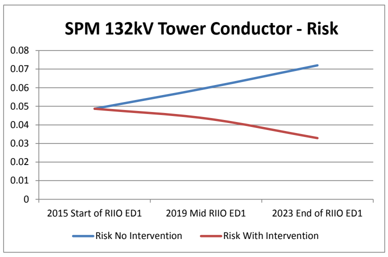


Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV & 33kV Tower Line Conductor Replacement	SPD	0.0	0.1	0.5	3.8	N/A
	SPM	0.9	4.3	4.1	32.4	368%
Total	SPEN	0.9	4.4	4.5	36.2	N/A

Asset Health and Criticality Indices

33kV OHL conductor is not covered by our HI and CI assessment processes. The impact of our plans on the health and criticality indices for 132kV tower line conductor is shown in the matrix below. The reduction in risk is in line with our long term strategy and reflective of the increase in investment over the period. The balance figure of -44 is due to 44km of tower line being replaced by poles.

SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	10	0	0	0	-11	-1
CI2	325	0	0	0	-364	-39
CI3	33	0	0	0	-37	-4
CI4	0	0	0	0	0	0
Total HI	368	0	0	0	-412	-44



Cost Benefit Analysis

We have considered a number of options for 132kV OHL investment and the summary outcome is shown below. Further detail is provided in the ANNEX C6 – Cost Benefit Analysis, reference 48 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback period			
				16 years	24 years	32 years	45 years
Base line	Patch and continue	Rejected	Ruled out due to ageing conductor and associated risk	£0.00	£0.00	£0.00	£0.00
1	Tension Stringing	Adopted	Adopted as most economic long term solution	-£1.67	£7.13	£12.87	£19.40
2	Catenary Blocking low tension	Rejected	Rejected as lower NPV in long term	£0.88	£8.32	£18.47	£18.47
3	Drop, recover and replace.	Rejected	Rejected as lower NPV	-£0.15	£2.33	£1.00	£4.20

8.3.2.7. 33kV and 132kV Overhead Tower Replacement and Refurbishment

Our Plan

33kV and 132kV Tower Refurbishment			
Licence	Average Population Refurbished (% per annum)	RIIO ED 1 Assets Refurbished	RIIO ED 1 Expenditure (£m)
SPD	13%	272	1.1
SPM	8%	779	9.4

33kV and 132kV Tower Painting			
Licence	Average Population Refurbished (% per annum)	RIIO ED 1 Assets Refurbished	RIIO ED 1 Expenditure (£m)
SPD	13%	272	0.8
SPM	6%	1,339	10.1

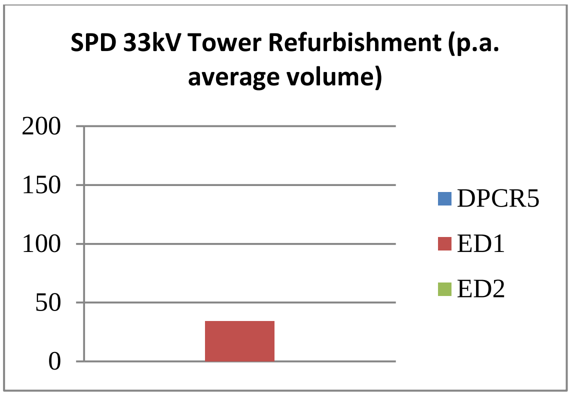
33kV and 132kV Tower Foundations			
Licence	Average Population Refurbished (% per annum)	RIIO ED 1 Assets Refurbished	RIIO ED 1 Expenditure (£m)
SPD	13%	272	1.9
SPM	9%	902	19.3

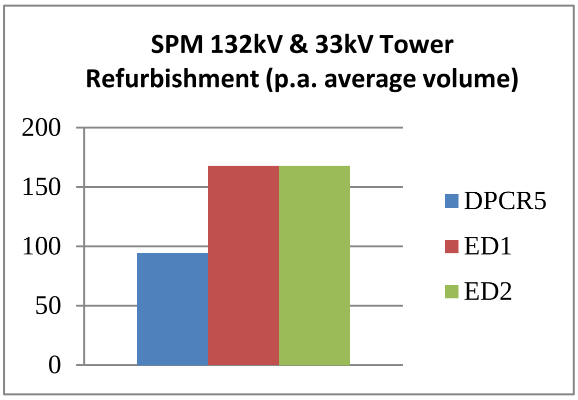
Tower steelwork has a life span of around 70 years, although this may be extended by up to 15 years if painted whilst the galvanising is intact or up to 8 years if painted after steelwork has started to corrode. Steelwork which has corroded beyond economic repair needs to be replaced.

Foundations are considered for repair or replacement when work to replace conductors or towers is proposed. Mid-life refurbishment of the “above ground” foundations of 132kV towers in SPM has prevented significant deterioration. This has not been the case for our 33kV tower population and work on foundations will be required alongside the conductor replacement.

Comparing ED1 to DPCR5

Due to the small population size and condition, for SPD we plan to refurbish all of our 33kV towers during ED1 which will leave them fit for purpose, requiring no investment in ED2. In SPM, our 33kV and 132kV tower refurbishment programme will continue into ED2.



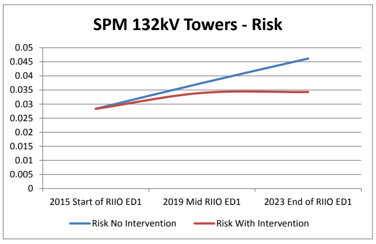


Asset Refurbishment		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
33kV & 132kV Tower Painting	SPD	0.0	0.0	0.1	1.1	N/A
	SPM	0.5	2.4	1.3	10.1	160%
33kV & 132kV Tower Refurbishment & Foundations	SPD	0.0	0.0	0.3	2.5	N/A
	SPM	2.3	11.4	3.6	28.7	57%
Total	SPEN	2.8	13.8	4.3	42.4	54%

Asset Health and Criticality Indices

The impact of our plans on health and criticality for 132kV towers are shown in the matrix below. There will be 243 towers removed and replaced with a 132kV pole line. The HI improvement reflects our steelwork and foundation refurbishment programmes.

	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	0	40	-6	-20	-32	-18
CI2	0	564	-58	-329	-397	-220
CI3	0	61	-11	-46	-9	-5
CI4	0	0	0	0	0	0
Total HI	0	665	-75	-395	-438	-243



8.3.2.8. 33kV and 132kV Tower Insulators and Fittings

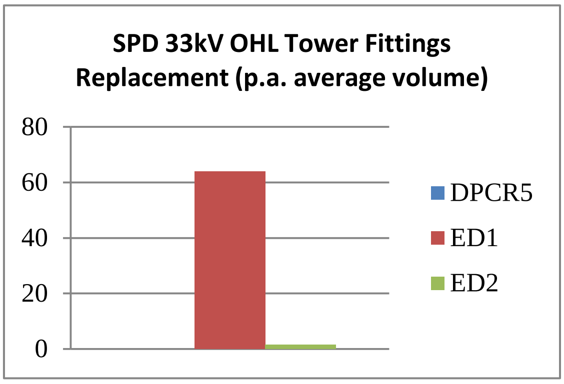
Our Plan

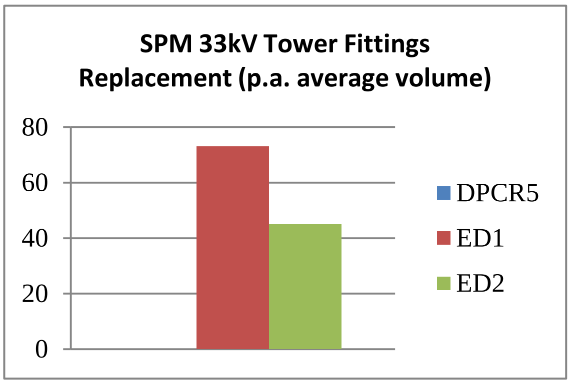
33kV and 132kV Tower Line Fittings				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPD	544	12.5%	544	1.2
SPM	2,108	4%	1,857	16.9

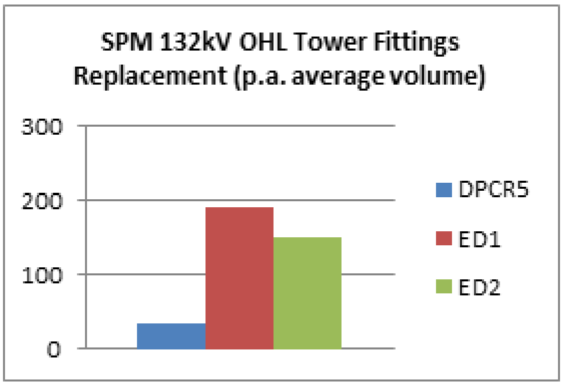
Glass or porcelain insulators generally deteriorate, with a life expectancy of approximately 40 years and, due to the age of our tower lines, many insulators are now in poor condition. We replace insulators alongside re-conductoring works for efficiency.

Comparing ED1 to DPCR5

Our replacement plan for 33kV and 132kV OHL tower fittings from DPCR5 to the end of ED2 is summarised in the charts below. In both our licence areas, our historic investment in 33kV tower line conductor has been modest and is now forecast to increase through the RIIO-ED1 period. In SPM, the 132kV tower fittings investment will increase in RIIO-ED1 and reduce in future years alongside our conductor replacement programme. More detail on our investment in 132kV and 33kV steel towers can be found in ANNEX C6 – Cost Benefit Analysis reference 6 - SPEN.







Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV & 33kV Tower Line Fittings	SPD	0.0	0.0	0.2	1.5	-
	SPM	0.5	2.4	2.1	16.9	349%
Total	SPEN	0.5	2.4	2.3	18.4	389%

8.3.3. Switchgear

Our investment plan for RIIO-ED 1 involves replacement, retrofitting or refurbishment of switchgear which is in poor condition and approaching, or at end of life. The plan has been developed in accordance with our asset management policies. Condition information combined with our asset replacement age based modelling, has been used to determine the intervention volumes. The use of condition and modelling data, combined with site criticality, ensures our plans reflect the key investment priorities. This approach provides prioritised, detailed work programmes at substation site specific level.

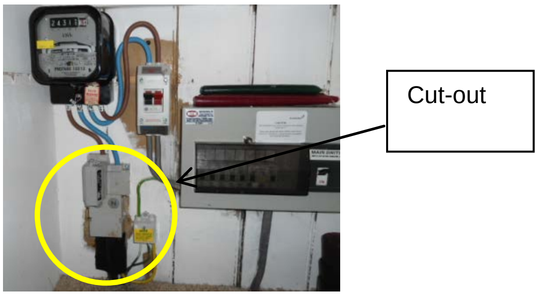
For further information please refer to ANNEXES C6 - LV Plant Strategy – SPEN, C6 - 11kV Substation Plant Strategy – SPEN, C6 - 33kV Substation Plant Strategy - SPEN and C6 - 132kV Substation Plant Strategy - SPEN.

8.3.3.1. LV Cut-outs

Our Plan

LV cut-out replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	27,200	0.2%	27,200	5.0
SPD	41,072	0.3%	41,072	7.6

Every customer connected to our network has a point at which the network cable terminates and the customer's installation starts. In domestic properties, this is generally where the electricity meter is situated, and is referred to as the Service Position and normally contains a LV cut-out as shown. Customer safety is the primary driver for our modernisation programme, and a higher priority is assigned to properties where customer access and egress may be affected by equipment failure.



Our ED1 modernisation works are targeted at LV cut-outs which have been identified as having reached or are approaching end of life. During these planned works, we will also inspect the condition of the metering and customer equipment and provide information where necessary to customers on any issues identified that we are unable to resolve during our work. We have increased costs associated with service position safety inspections in ED1 to reflect this.

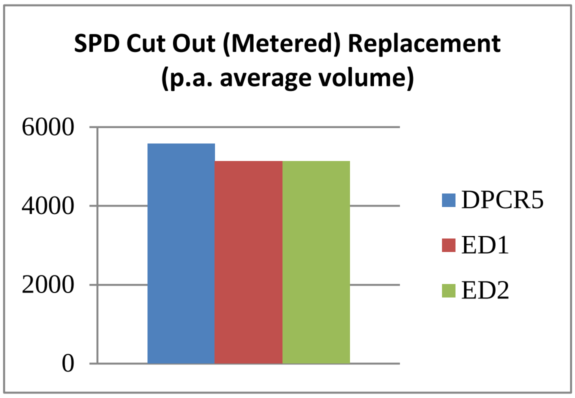
We have also included a separate budget for cut-out replacement resulting from the Smart Meter roll-out. This is reported at Section 10 (Smart Metering Costs), below.

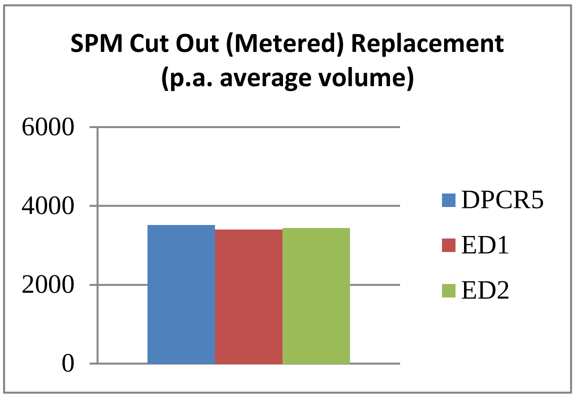
Currently, we have 1,478,461 LV cut-outs in SPM and 1,976,485 in SPD and we intend to replace 1.8% and 2.1% during ED1 respectively.

Comparing ED1 to DPCR5

Cut Outs		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Cut outs	SPD	1.2	6.0	0.9	7.6	-25%
	SPM	0.8	3.8	0.6	5.0	-25%
Total		2.0	0.8	1.5	12.6	-25%

Customer safety is a top priority for us and during ED1 we plan to continue our commitment to inspect and invest in these assets. Our ongoing replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.





Cost Benefit Analysis

We have considered a number of options for LV cut out investment and the summary outcome is shown below. Further detail is provided in ANNEX Cost benefit Analysis reference no 11 - SPEN. Option 2 is on the face of it a more attractive proposition but would involve multiple visits to a customer property to replace a poor condition service separately to a poor condition cut out. We do not think this is good customer service due to the inconvenience to customers.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Replace HI5 poor condition cut-outs and services.	Adopted		£0.00	£0.00	£0.00	£0.00
2	Replace HI5 poor condition cut-outs only.	Rejected	Rejected due to customer service and safety implication.	£0.97	£1.12	£1.22	£1.31
3	Replace HI5 poor condition cut-outs and upgrade service cables for LCT	Rejected	Rejected due to negative NPV	-£0.24	-£0.45	-£0.58	-£0.72

8.3.3.2. LV Plant in Substations

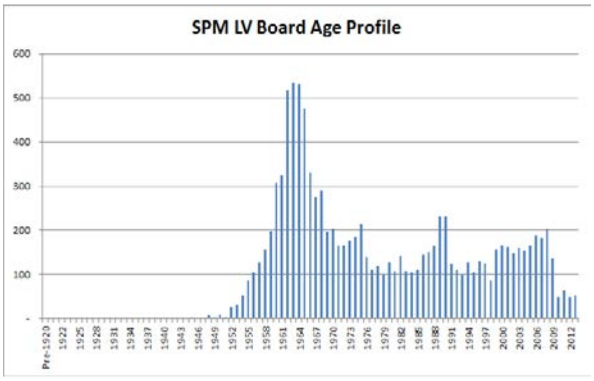
Our Plan

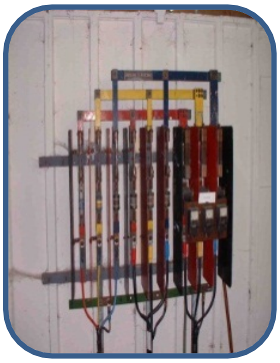
LV substation board replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	80	0.1%	80	0.8
SPD	64	0.2%	64	0.6

LV substation pillar replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	160	1.2%	160	0.7
SPD	336	0.3%	336	1.9

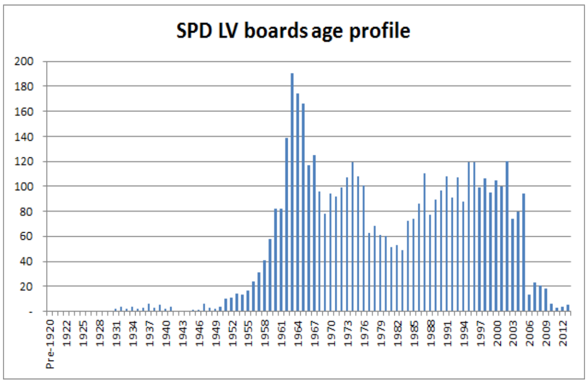
Our substations contain exposed LV indoor boards and enclosed LV indoor and outdoor pillars which carry fuses to protect the LV cable network and distribute electricity to street pillars and link boxes. The LV pillars can either be freestanding or mounted on transformers. These assets deteriorate over time and we plan to replace end of life assets with new equipment during ED1.

Our asset age profile indicates that a high proportion of units were installed during the 1950s.

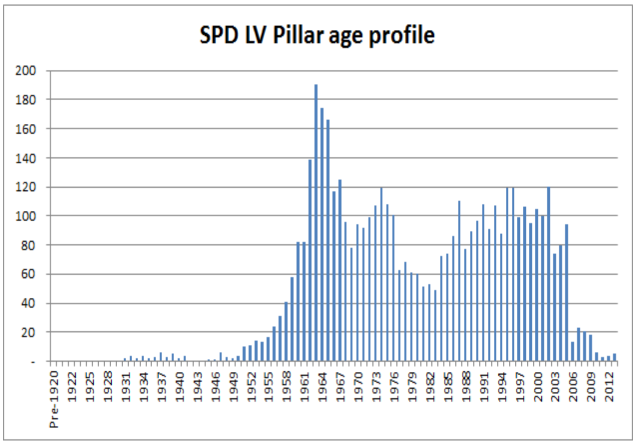


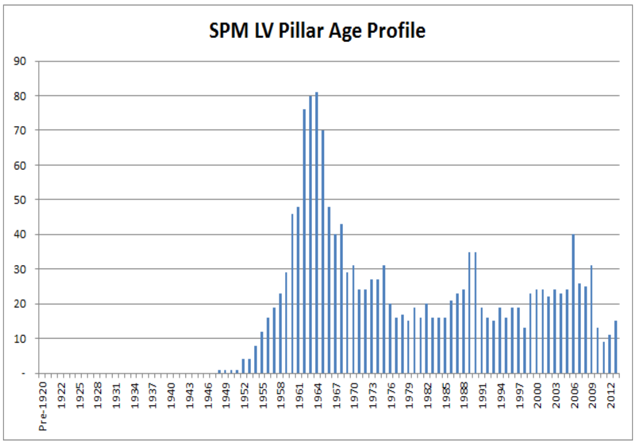


LV indoor board



The age profiles for indoor LV boards highlight the volume of assets installed in the 1950s and 1960s. Currently we have 10,758 in SPM and 4,850 in SPD and we intend to replace 0.7% and 1.3% during ED1 respectively.



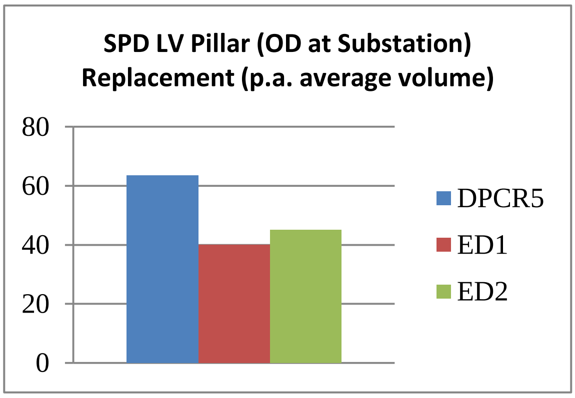


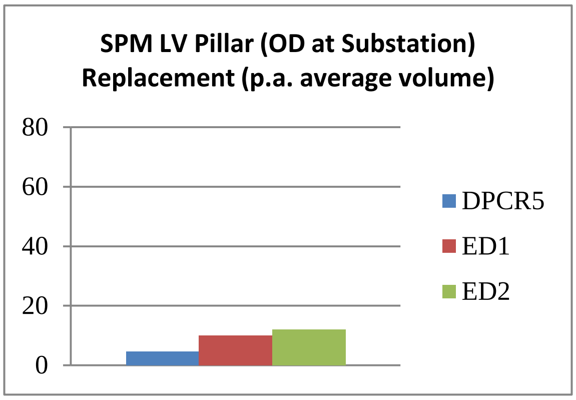
The age profiles for our outdoor pillars also show large volumes installed in the 1950s and 1960s. Currently we have 1,623 LV substation pillars in SPM and 15,611 in SPD and we intend to replace 9.9% and 2.2% during ED1 respectively.

Comparing ED1 to DPCR5

Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
LV Substation Boards and Pillars	SPD	0.7	3.5	0.3	2.6	-55%
	SPM	0.0	0.2	0.2	1.5	N/A
Total	SPEN	0.7	3.7	0.5	4.1	-32%

Our LV pillar replacement plan from DPCR5 to the end of ED2 is summarised in the charts below. This profile reflects our strategy to increase the level of activity into ED2, to remove poor condition assets.





8.3.3.3. LV Underground Link Boxes and Street Pillars

Our Plan

LV underground link box and street pillar replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	2,352	1.4%	2,352	12.4
SPD	2,512	1.5%	2,512	13.7

LV underground link box refurbishment			
Licence	RIIO ED 1 Assets Refurbished	Average Population Refurbished (% per annum)	RIIO ED 1 Expenditure £m
SPM	4,560	2.75%	1.5
SPD	1,136	1.5%	0.4

Underground link boxes and above ground street pillars, the vast majority of which are located in public areas, are used to minimise disruption to customers when we are working on the network and are used to help restore supplies expediently after a fault.

Due to their location, public proximity and vulnerability to physical damage and interference, above ground low voltage street pillars and underground link boxes are inspected on a regular basis and poor condition assets are repaired, refurbished or replaced as appropriate. LV street pillars are given a high priority as damage can expose live parts, presenting a risk to members of the public. The programme in this area is a continuation of our strategy over the last five years and will continue at a steady run rate in the longer term. We plan to replace end of life assets with new, modern equipment.

Also, as link boxes are normally under public footpaths, the lid or cover can become damaged and cause a public hazard. Therefore we have a refurbishment programme in ED1 to replace any covers in this condition.


LV street pillar

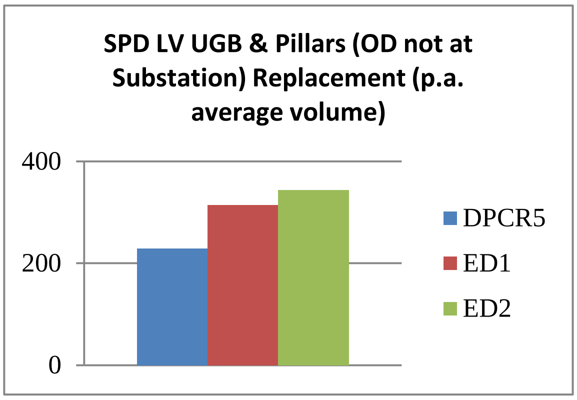

LV underground link box

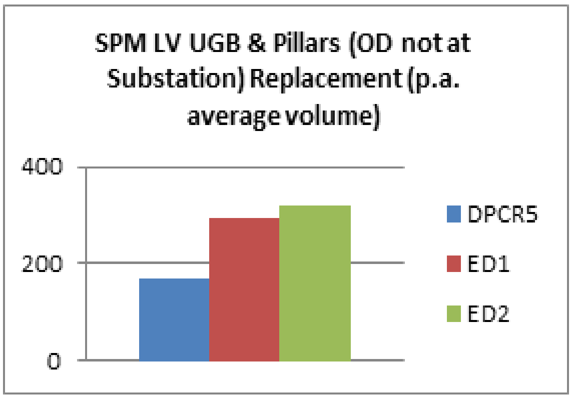
Currently we have 21,448 LV link boxes and LV street pillars in SPM and 21,019 in SPD and we intend to replace a total of 11% and 12% during ED1 respectively. We also plan to refurbish a total of 22% link boxes in SPM and 12% in SPD. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

Comparing ED1 to DPCR5

Asset Replacement Expenditure	DPCR5		RIIO -ED1				% Difference Per Annum	
	Per Annum (£m)		Total (£m)		Per Annum (£m)			
	SPD	SPM	SPD	SPM	SPD	SPM	SPD	SPM
LV UGB & LV Pillars (OD not at Substation)	1.80	1.76	13.71	12.39	1.71	1.55	-5%	-12%

These profiles reflect the increasing need to replace poor condition assets from ED1 into ED2, especially those that can pose a hazard to the public.





Cost Benefit Analysis

We have considered two options for LV plant investment and the summary outcome is shown below. Further detail is provided in the ANNEX Cost Benefit Analysis reference no 62 - SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Replace and refurbishment	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	Replace the full programme of LV assets	Rejected	Rejected due to negative NPV	-£12.86	-£16.42	-£18.82	-£21.29

8.3.3.4. Ground Mounted HV Switchgear

Our Plan

Ground mounted HV switchgear replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure £m
SPM	2,779	1.8%	2,779	46.9
SPD	2,403	1.1%	2,403	29.8

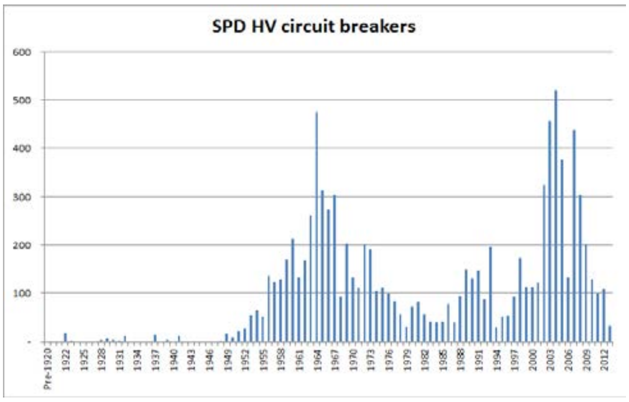
Ground mounted HV switchgear refurbishment			
Licence	RIIO ED 1 Assets Refurbished	Average Population Refurbished (% per annum)	RIIO ED 1 Expenditure £m
SPM	466	0.3%	9.4
SPD	1,340	0.6%	10.4

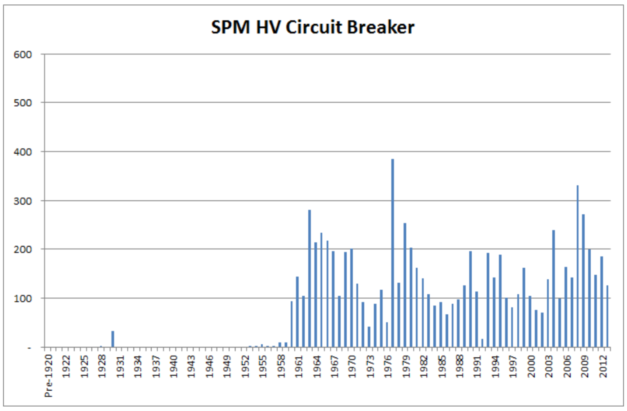
Our ED1 plan targets the replacement and refurbishment of HV circuit breakers, HV ring main units and HV switches that have type based operational restrictions, are performing poorly or are in poor condition. Failure of an HV circuit breaker will result in loss of supply, can damage the plant it is designed to protect and there is also the possibility, albeit very low, of serious injury to either staff or members of the public should anyone be in close proximity to a unit suffering catastrophic failure.

Our strategy is to replace end of life assets based on an assessment of operational adequacy and on-site condition information gathered during routine inspections, planned and post fault maintenance interventions.

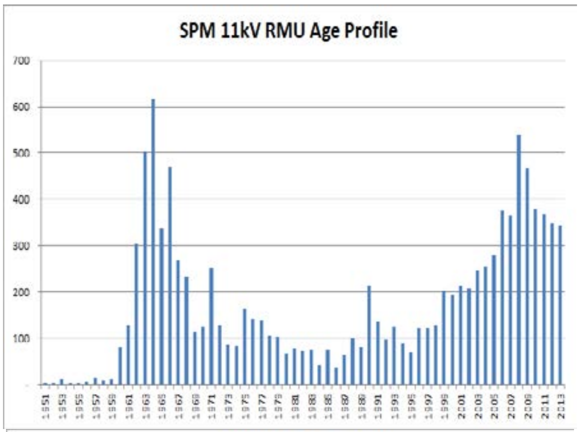
In addition to complete replacement, several manufacturers have developed solutions which enable the moving portion of life expired oil filled circuit breakers to be replaced (“retrofitted”) with a modern low maintenance equivalent.

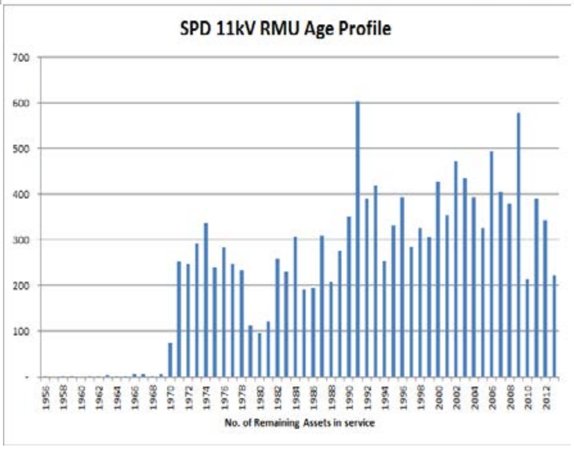
In addition to the retrofit programme, we plan to refurbish some circuit breakers categorised as Health Index 4 as a viable economic option to extend their serviceable life, and slow the deterioration of this asset over the coming decades. The scope for circuit breaker refurbishment includes both the fixed and moving portions.





Also, we have a high dependency on the reliability of ring main units (RMUs) and many of these were installed in the 1970s and are deteriorating at a similar rate. In order to effectively manage these high volume assets, we are introducing a targeted refurbishment programme.





Currently we have 8,106 HV circuit breakers in SPM and 9,557 in SPD and we intend to replace 5.9% and 10.2% during ED1 respectively. We also plan to refurbish 4.5% in SPM and 5.7% in SPD.

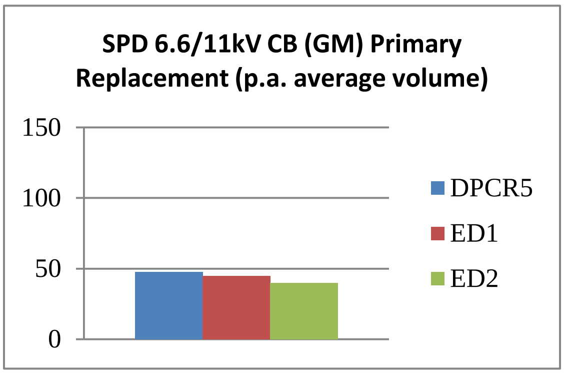
We have 11,021 HV RMUs in SPM and 13,637 in SPD and we intend to replace 21% and 8.1% during ED1 respectively. We also intend to refurbish 100 RMUs in SPM and 800 in SPD during ED1.

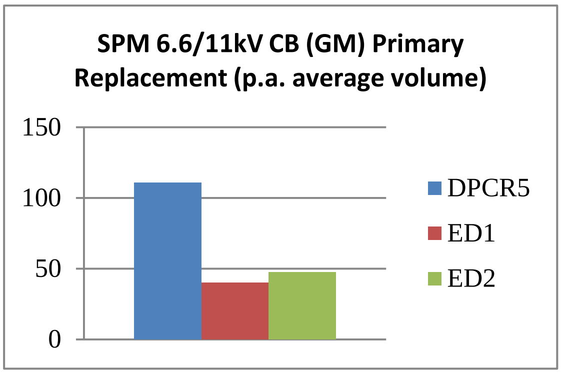
Comparing ED1 to DPCR5

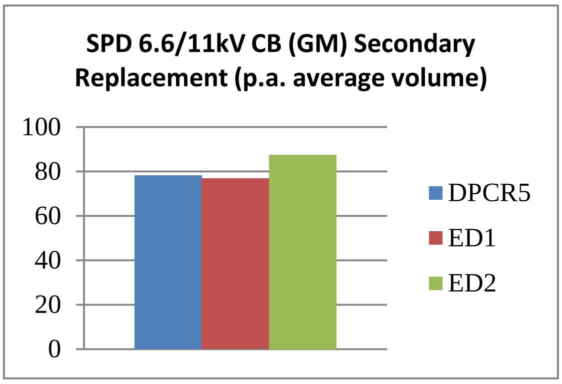
Asset Replacement, Refurbishment		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
11kV Primary Switchgear Replacement	SPD	1.5	7.7	1.4	11.5	-7%
	SPM	3.8	19.2	1.3	10.3	-66%
11kV Primary Switchgear Refurbishment	SPD	0.0	0.1	1.2	9.2	N/A
	SPM	0.0	0.2	1.2	9.3	N/A
Total	SPEN	5.4	27.1	5.0	40.3	-7%

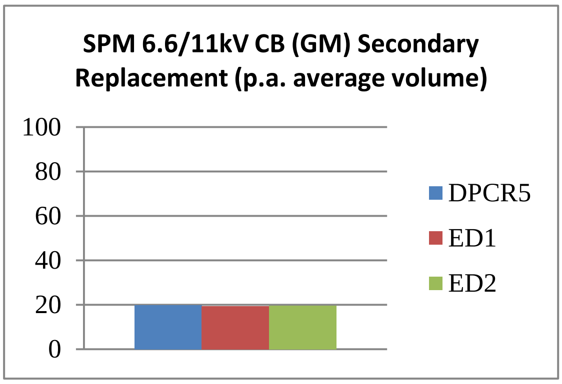
Asset Replacement, Refurbishment		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
11kV Secondary Switchgear Replacement	SPD	2.9	14.7	2.3	18.3	-22%
	SPM	5.2	26.0	4.6	36.6	-12%
11kV Secondary Switchgear Refurbishment	SPD	0.0	0.0	0.1	1.2	N/A
	SPM	0.0	0.0	0.0	0.1	N/A
Total	SPEN	8.1	40.6	7.0	56.3	-14%

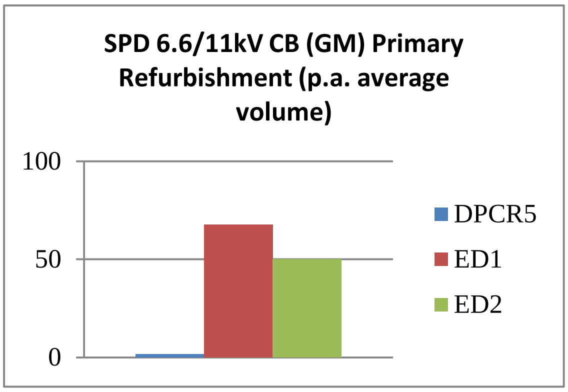
Our HV circuit breaker replacement plan from DPCR5 to the end of ED2 is summarised in the charts below. The SPD profile highlights our continued requirement to replace our end of life assets, with this reducing in ED2 reflecting the cumulative effect of our replacement and refurbishment activity. In SPM during DPCR5, we have successfully replaced a significant volume of our end of life assets resulting in the reduction in activity in ED1. We expect to increase our activity in ED2 as a result of our SPM type analysis on the risk profiles. There is more opportunity to refurbish primary circuit breakers in SPD than in SPM.

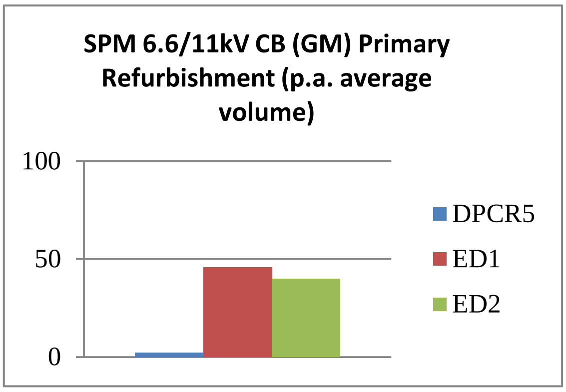




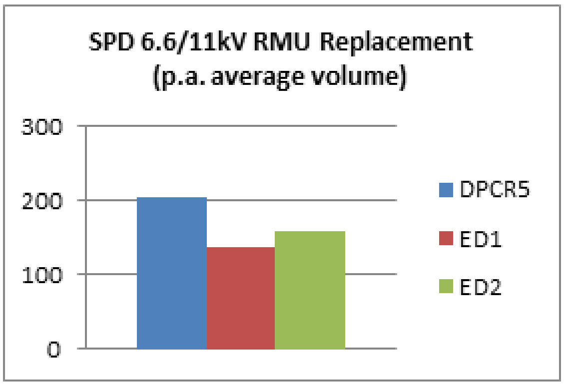


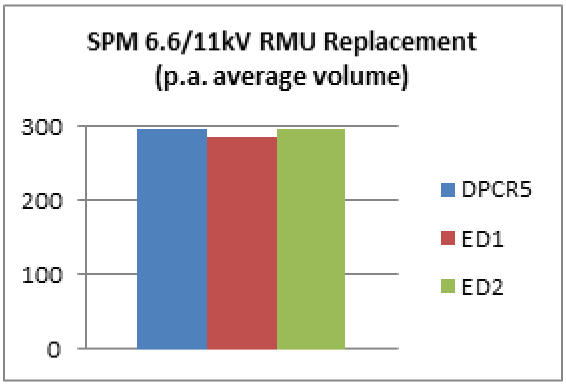


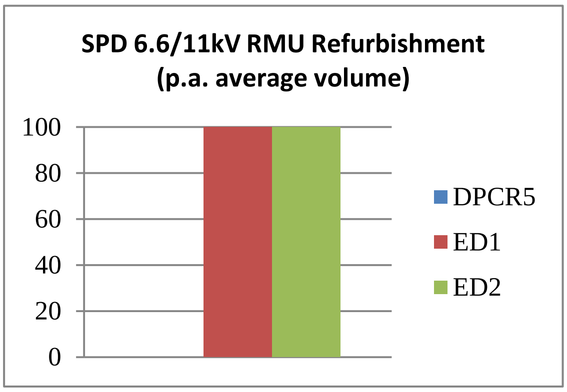


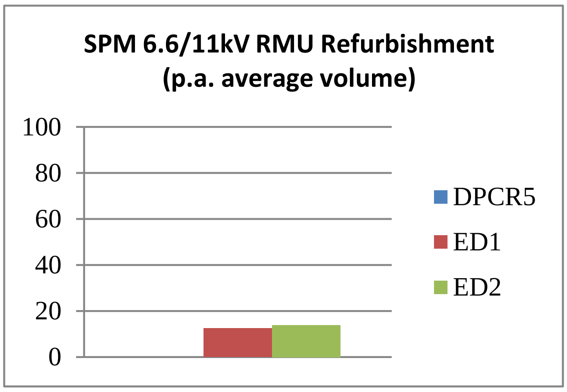


Our HV RMU replacement plan from DPCR5 to the end of ED2 is summarised in the charts below. Our SPD programme will reduce into ED1 and our deterioration modelling indicates a slight pick up again in ED2. SPD and SPM have an old population of RMUs and the expectation is these will continue to deteriorate and require replacing throughout ED2. The deterioration will be offset by our refurbishment activity.







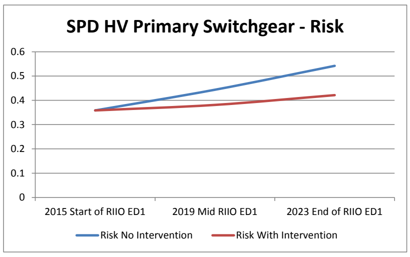


Asset Health and Criticality Indices

The relative risk measures for plant with and without investment are shown below. Replacements are represented as HI5 to HI 1 movement, retrofit from HI4 to 2, and refurbishment as HI4 to 3 as a minimum.

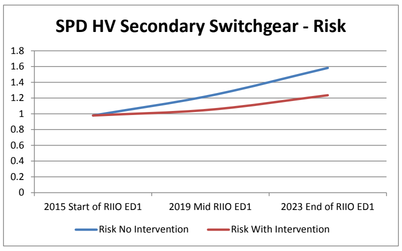
SPD 11kV primary switchgear – ED1 movements

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	165	104	126	-230	-165	0
CI2	111	84	102	-186	-111	0
CI3	58	27	32	-59	-58	0
CI4	25	29	36	-65	-25	0
Total HI	359	244	296	-540	-359	0



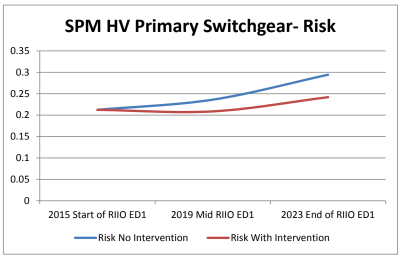
SPD 11kV distribution switchgear – ED1 movements

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	809	0	325	-325	-809	0
CI2	703	0	316	-316	-703	0
CI3	298	0	107	-107	-298	0
CI4	234	0	52	-52	-234	0
Total HI	2044	0	800	-800	-2044	0



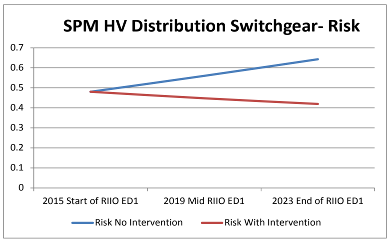
SPM 11kV primary switchgear– ED1 movements

SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	142	73	126	-199	-142	0
CI2	81	33	57	-90	-81	0
CI3	55	17	29	-46	-55	0
CI4	45	11	20	-31	-45	0
Total HI	323	134	232	-366	-323	0



SPM 11kV distribution switchgear – ED1 movements

	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	918	0	37	-37	-918	0
CI2	811	0	35	-35	-811	0
CI3	537	0	23	-23	-537	0
CI4	190	0	5	-5	-190	0
Total HI	2456	0	100	-100	-2456	0



Cost Benefit Analysis

We have considered a number of options for HV switchgear investment and the summary outcome is shown below. Further detail is provided in the ANNEX Cost Benefit Analysis reference no 2 - SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Baseline - Replacement only	Rejected	not the best cost/benefit option	£0.00	£0.00	£0.00	£0.00
2	Retrofit / Refurbish / Replace	Adopted	The options on this sheet clearly demonstrate both refurbishment and retrofitting are beneficial and should be delivered where they are feasible and meet the strategy. A optimised blend of the 3 Rs is the adopted option.	£15.51	£15.35	£11.70	£8.52
3	Refurbish Only	Rejected	Not the most economic option over the life of the equipment	£19.28	£13.47	£10.33	£6.99
4	Retrofit Only	Rejected	This option cannot be delivered as not all types of switchgear are capable of being retrofitted	£20.36	£21.13	£13.80	£6.95

Manweb Company Specific Factors

We incur incremental costs in the replacement of 11kV RMUs on the SPM urban interconnected network. This incremental cost is included in our Special Factors assessment.

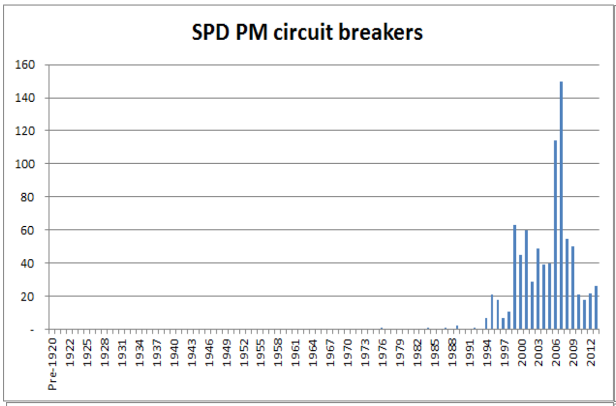
SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
HV Non Load (11 & 6.6kV) Investment				
X- type Ring Main Unit asset replacement	CV3	38	£7.33	Based on ED1 plan to replace 1706* HV X type Ring Main Units in ED1, these have discrete SPM components. Cost differential based on delivering same volume at SPM Y type RMU unit cost.

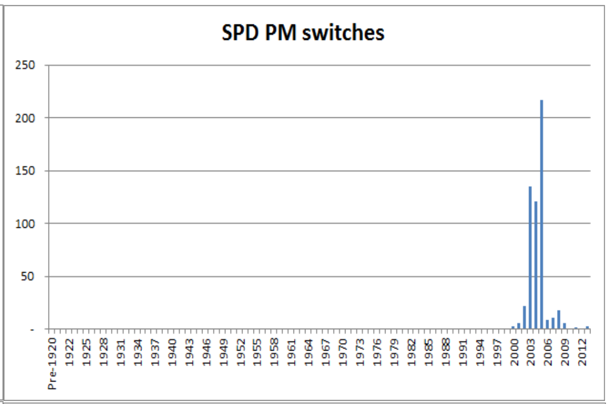
8.3.3.5. 33kV and HV Pole Mounted Switchgear

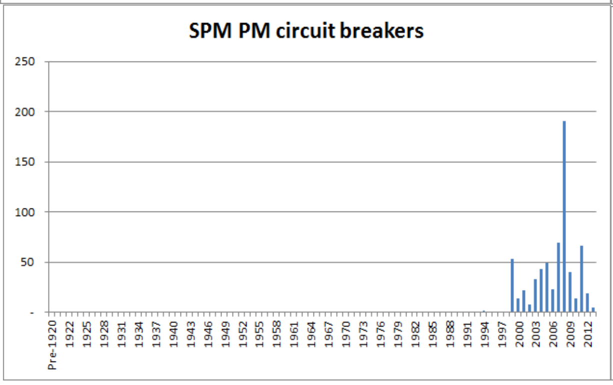
Our Plan

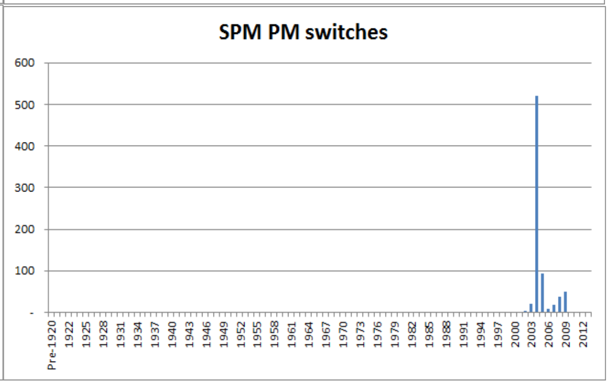
HV pole mounted switchgear replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	1,376	1%	1,376	2.5
SPD	1,448	1.6%	1,448	2.6

Our 33kV and HV overhead line networks contain switchgear mounted on poles that assist in the protection and efficient operation of our network. These assets can be categorised as circuit breakers, switches and fuses. They deteriorate over time, ultimately impacting network performance.









Pole mounted switch

Pole mounted circuit breaker

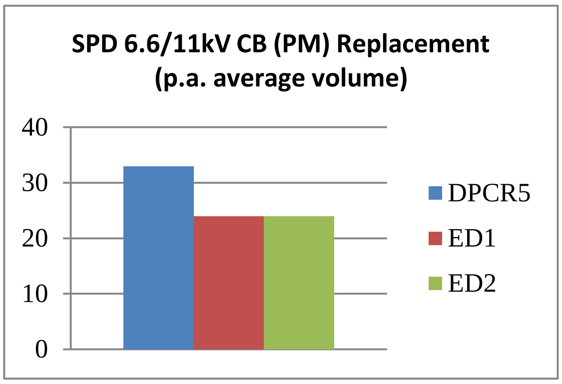
Although these assets are relatively new, they have electronic components that have a shorter life than the switchgear element and typically the complete unit needs to be replaced when these components fail. It is important to highlight that the majority of the replacement volume in ED1 is for switches and fuses that have no age profile available and therefore not shown on these graphs.

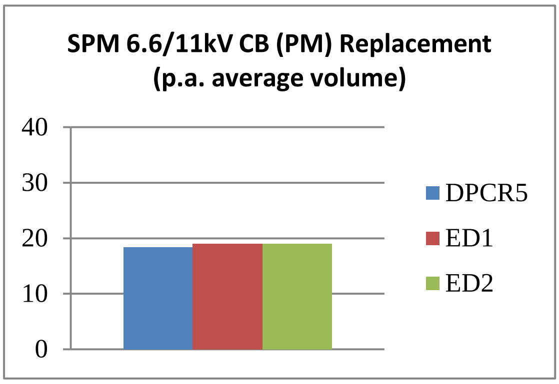
Currently we have 17,132 pole mounted switchgear units in SPM and 11,048 in SPD and we intend to replace 8% and 13% during ED1 respectively.

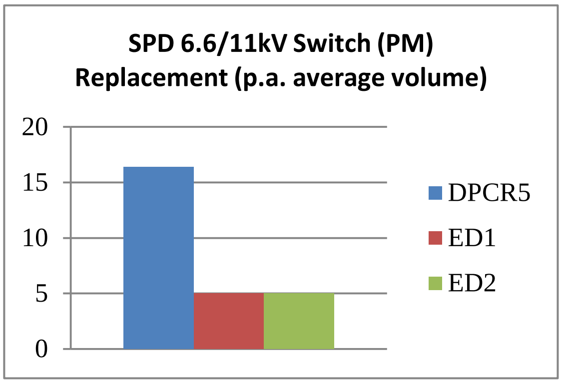
Comparing ED1 to DPCR5

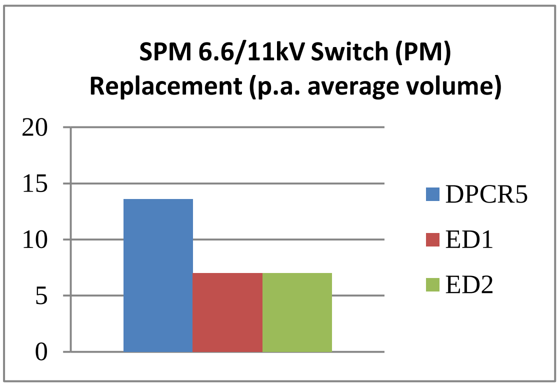
Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Pole Mounted Switchgear	SPD	0.6	3.0	0.3	2.6	-45%
	SPM	0.2	1.1	0.3	2.5	43%
Total	SPEN	0.8	4.1	0.6	5.1	-22%

Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below. The replacement of pole mounted equipment will continue through to ED2 at similar levels recognising the life expectancy of these assets.









8.3.3.6. 33kV Switchgear

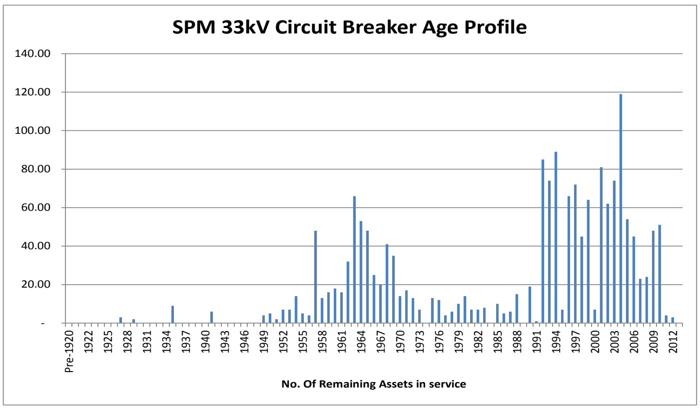
Our Plan

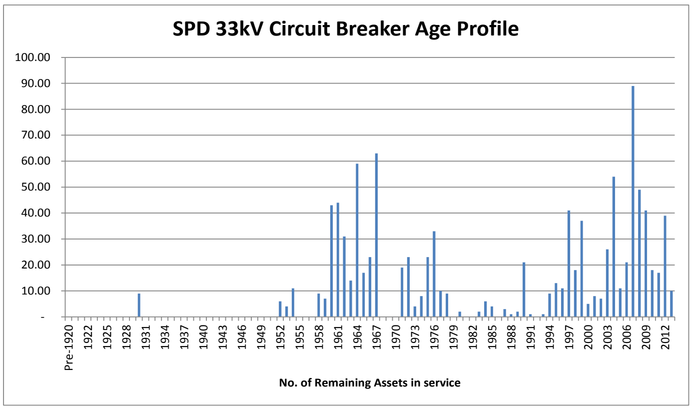
33kV switchgear replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	643	1.9%	453	29.0
SPD	417	2.2%	153	13.2

Switchgear deteriorates over time as a result of environmental exposure and mechanical wear. Failure of 33kV switchgear can result in loss of supply, damage to the plant it is designed to protect and there is also the possibility, albeit very low, of serious injury to either staff or members of the public should anyone be in close proximity to a unit suffering catastrophic failure.

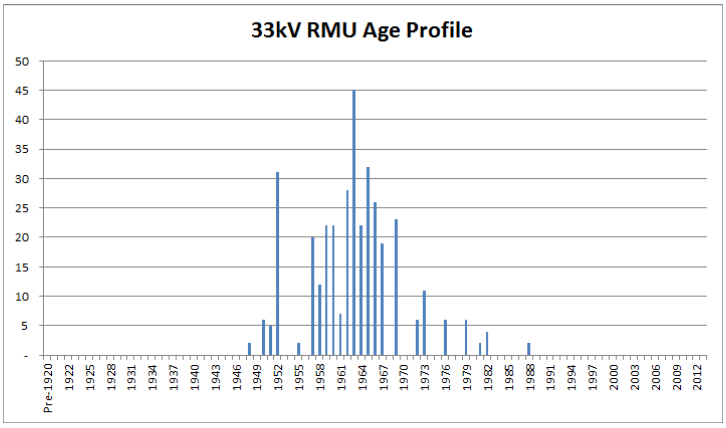
We have a considerable population of ageing 33kV bulk oil circuit breakers and RMUs on our network, installed in the 1950s and 60s. Some of these are now subject to operational restrictions following failures in the industry and our condition surveys have identified other issues including widespread plinth degradation, corrosion of the main tanks causing oil leaks, along with corrosion of mechanism housings and concrete supporting structures. Given their complexity and obsolescence, we do not have economic refurbishment options available to extend the lives of this type of equipment and therefore in ED1 we will continue to replace them with modern equivalent SF6 circuit breakers.

33kV circuit breakers





33kV RMUs (SPM only)



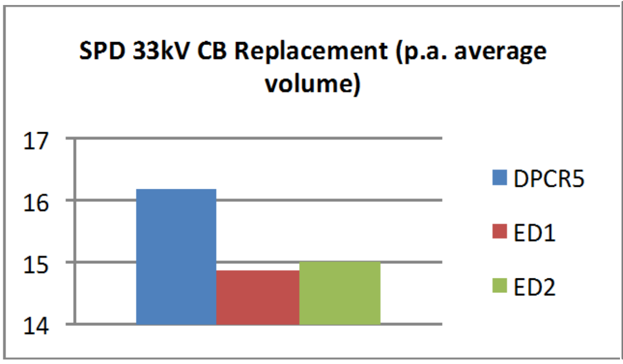
Currently we have 1784 33kV circuit breakers in SPM and 1036 in SPD and we intend to replace 8.5% and 11.5% during ED1 respectively. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

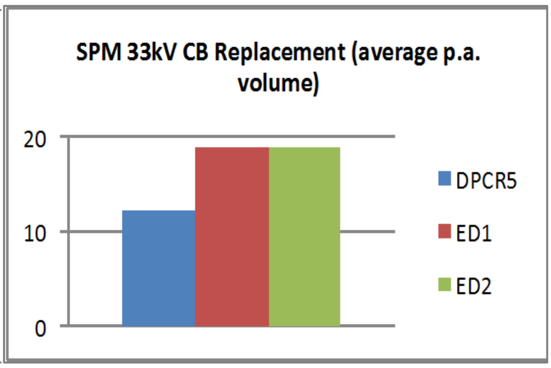
We have 361 33kV RMUs in SPM and we intend to replace 9.1% during ED1. Our replacement plan from DPCR5 to the end of ED2 is summarised in the chart below.

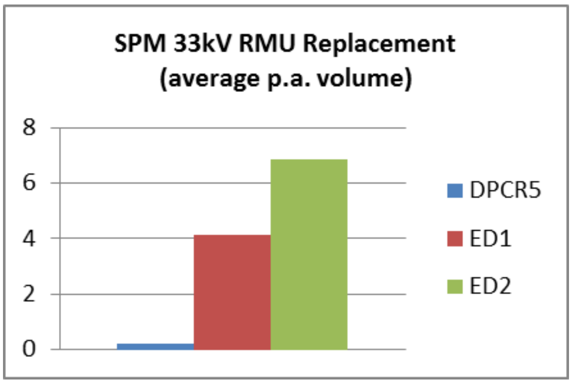
Comparing ED1 to DPCR5

Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa £m	Total £m	ED1 pa £m	Total £m	% change
33kV Switchgear Replacement	SPD	2.3	11.5	1.7	13.2	-28%
	SPM	2.3	11.6	3.6	29.0	57%
Total	SPEN	4.6	23.0	5.3	42.3	15%

Due to their type, age and condition, refurbishment of 33kV circuit breakers and RMUs is not a viable economic option. We will continue to replace these units in the forthcoming price review periods.



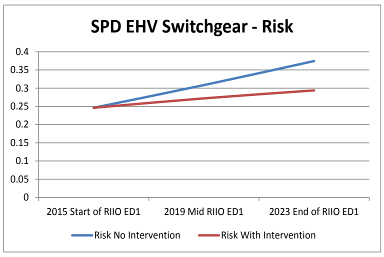




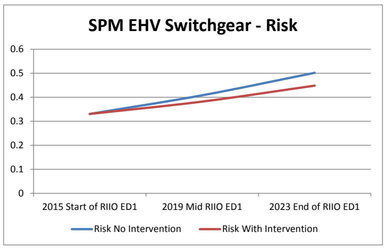
Asset Health and Criticality Indices

The net movements resulting from asset replacement in our HI and CI ratings over ED1 for our 33kV switchgear are shown in the following tables.

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	68	0	0	-4	-64	0
CI2	36	-2	-4	0	-30	0
CI3	15	-6	-1	-1	-7	0
CI4	0	0	0	0	0	0
Total HI	119	-8	-5	-5	-101	0



SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	204	-2	-1	-20	-127	54
CI2	16	0	0	-3	-9	4
CI3	11	0	0	-1	-7	3
CI4	20	0	0	0	-15	5
Total HI	251	-2	-1	-24	-158	66



Cost Benefit Analysis

We have considered two options for 33kV switchgear investment and the summary outcome is shown below. Further detail is provided in the ANNEX C6 - Cost Benefit Analysis reference 59 - SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Replace EHV 33kV Circuit breakers in line with our current plan	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	Refurbish rather than replace with a 10 year life extension	Rejected	Rejected due to negative NPV	-£0.53	-£6.19	-£9.65	-£13.47

Our 33kV RMU fleet is specific to SPM. The only economically viable risk management strategy is replacement with the modern equivalent solution. Due to the complexity of these units, the refurbishment requirement would be provided by a specialist supplier, off site. The additional costs to manufacture and replace the special type end boxes for the specific type cable add to the high refurbishment cost. Detail can be accessed in our ANNEX C6 Cost benefit Analysis reference – 60 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Replace EHV 33kV Circuit breakers in line with our current plan	Adopted	The most economic option over the lifetime of the equipment	£0.00	£0.00	£0.00	£0.00
1	Replace based refurbishment	Rejected	Rejected on the basis that this is not the most economic option over the lifetime of the equipment	-£0.53	-£6.19	-£9.65	-£13.47

Manweb Company Specific Factors

There are a number of elements of our 33kV investment programme that incur additional costs as a result of the design of the SPM urban interconnected network. These are summarised in the following table.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
33kV Ring Main Unit asset replacement	CV3	69		Based on ED1 plan to replace 33 x 33kV Ring Main Units in ED1, with no SPEM approved 33kV RMU's the cost differential is reported under indoor 33kV CB's category as the replacement option
Outdoor ground mounted circuit breaker asset replacement	CV3	71	£ 7.79	Based on ED1 plan to replace 99 outdoor 33kV CB's at Primary sites, not be required on Traditional Industry Networks. Costs for 2 CB's at Grid sites excluded from SPM RF case
Indoor ground mounted circuit breaker asset replacement	CV3	70	£ 11.76	Based on ED1 plan to replace 99 outdoor 33kV CB's as an alternative to RMU's and 6 CB's at Primary sites, that would not be required on Traditional Industry Networks. Costs 45 indoor CB's at Grid sites excluded from SPM RF case

8.3.3.7. 132kV Switchgear

Our Plan

132kV switchgear replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	263	2.3%	121	33.8

The volumes in the above table contain all categories of switchgear including circuit breakers, disconnectors and earth switches.

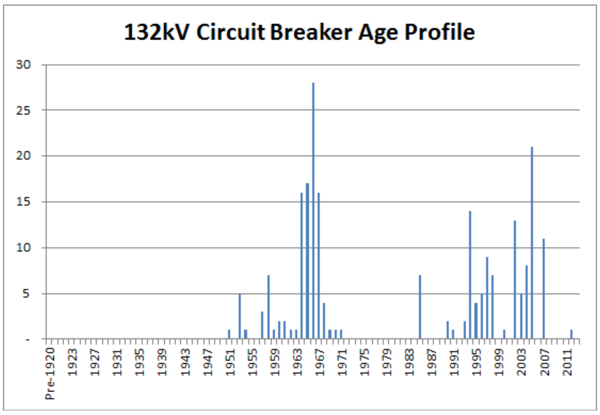
Nearly 50% of the 132kV circuit breakers on SPM's network are greater than 40 years old, amongst the oldest remaining in the industry. In DPCR5, we began to replace air blast and bulk oil circuit breakers which are now obsolete and cannot be efficiently repaired. Following replacement of 24 such units in DPCR5, we will have 80 remaining and we plan to replace 48 in ED1, with the remaining 32 by 2031. These strategically important assets are in some cases located in densely populated areas. They were installed in the 1950-60s and are generally outdoors in sizeable, expensive to maintain compounds. The sites have been prioritised for replacement using condition, location and potential impact on customers.

The circuit breakers have become increasingly unreliable and more difficult to service or refurbish due to their complex design. In addition, there is a lack of spare parts and manufacturer support. There is also significant cost and network outage time associated with maintenance, increasing the risk of losing supply to customers. Associated concrete structures have also deteriorated as a result of their environmental exposure.

The following 132kV SPM switchgear have been identified and planned for replacement in ED1:

Project	Volume	Solution	Bus Section/Coupler	Feeder Bay	Tx Bay
Birkenhead 132kV	10	Indoor GIS	3	5	2
Crewe 132kV	13	Indoor GIS	3	7	3
Gateacre 132kV	2	Outdoor AIS	2		
Lister Drive 132kV	12	Indoor GIS	3	6	3
Rainhill 132kV	12	Indoor AIS	3	9	
Speke 132kV	1	Outdoor AIS	1		

Our plans include utilising air insulated switchgear (AIS) and gas insulated switchgear (GIS) to achieve the most efficient replacement option for each individual site. We are able to achieve industry leading unit costs for our GIS switchgear through our global procurement processes. Where appropriate, we have rationalised substation designs to deliver a more efficient outcome.

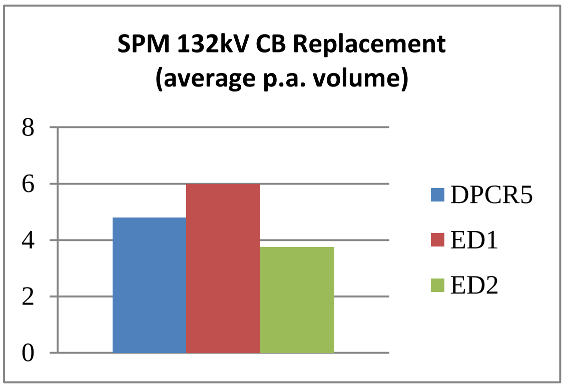


Currently we have 219 132kV circuit breakers in SPM and we intend to replace 23% during ED1. Our replacement plan from DPCR5 to the end of ED2 is summarised in the table below.

Comparing ED1 to DPCR5

Asset Replacement		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV Switchgear	SPM	7.3	36.3	4.2	33.8	-42%
Total	SPEN	7.3	36.3	4.2	34.4	-42%

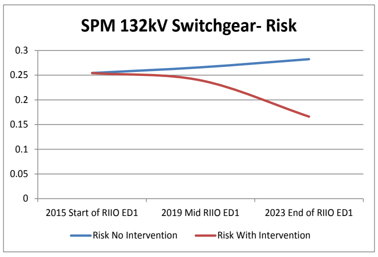
This profile reflects our strategy to remove all end of life units by the end of ED2.



Asset Health and Criticality Indices

The net movements in our HI and CI ratings over ED1 for our 132kV circuit breakers are shown in the following table.

SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	12	0	0	0	-12	0
CI2	24	0	0	0	-24	0
CI3	14	-2	0	0	-12	0
CI4	0	0	0	0	0	0
Total HI	50	-2	0	0	-48	0



Two HI2 switches will be replaced at Lister Drive as part of our total site switchgear change from outdoor to indoor GIS; this is supported by our CBA, below.

Cost Benefit Analysis

We have considered a number of options for 132kV switchgear investment and the summary outcome is shown below. Further detail is provided in the ANNEX Cost Benefit Analysis reference no's 52, 53 and 54 - SPEN.

132kV Lister Drive

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	AIS inline rebuild	Rejected	Rejected as not most economic option	£0.00	£0.00	£0.00	£0.00
1	GIS offline rebuild	Adopted	Most economic option	£2.57	£2.79	£2.93	£3.11
2	Replace OCB's with GCB	Rejected	Rejected due to negative NPV	£1.07	£0.69	£0.43	£0.12

132kV Birkenhead

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	AIS inline rebuild	Rejected	Rejected as not most economic option	£0.00	£0.00	£0.00	£0.00
1	GIS offline rebuild	Adopted	Most economic option	£1.05	£1.04	£1.04	£1.06
2	Replace OCB's with GCB	Rejected	Rejected due to negative NPV	£1.13	£0.78	£0.54	£0.26

132kV Crewe

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	AIS inline rebuild	Rejected	Rejected as not most economic option	£0.00	£0.00	£0.00	£0.00
1	GIS offline rebuild	Adopted	Most economic option	£0.78	£0.67	£0.61	£0.56
2	Replace OCB's with GCB	Rejected	Rejected due to negative NPV	£1.32	£0.97	£0.73	£0.46

8.3.4. Transformers

Our investment plan for transformers in RIIO-ED 1 involves both replacement and refurbishment and has been developed in accordance with our asset management policy. Condition information combined with our asset replacement age based modelling, has been used to determine the intervention volumes. The use of condition and modelling data, combined with site criticality, ensures our plans reflect the key investment priorities. This approach provides prioritised, detailed work programmes at substation site specific level.

For further information please refer to ANNEXES C6 - LV Plant Strategy – SPEN, C6 - 11kV Substation Plant Strategy – SPEN, C6 - 33kV Substation Plant Strategy - SPEN and C6 - 132kV Substation Plant Strategy - SPEN.

8.3.4.1. HV Transformers (ground and pole mounted)

Our Plan

HV ground mounted transformer replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	845	0.9%	845	9.0
SPD	714	0.6%	714	6.9

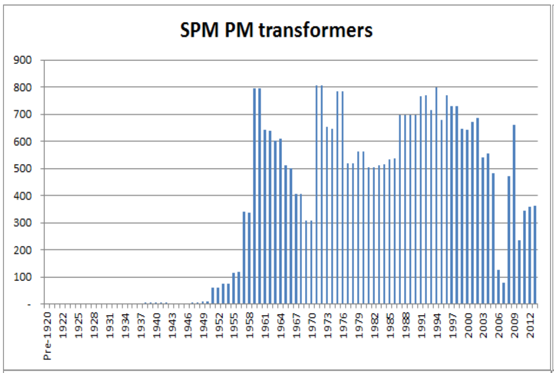
HV ground mounted transformer refurbishment			
Licence	RIIO ED 1 Assets Refurbished	Average Population Refurbished (% per annum)	RIIO ED 1 Expenditure (£m)
SPM	1,272	1.4%	6.3

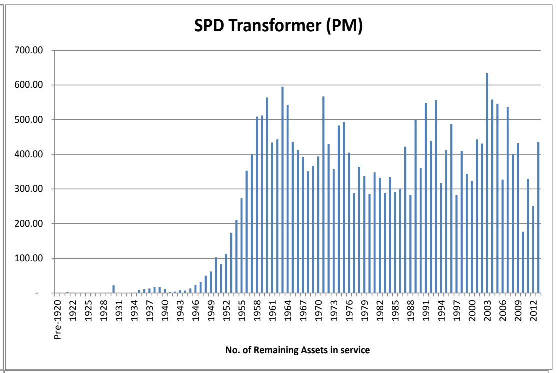
HV pole mounted transformer replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	1,536	0.6%	1,536	4.1
SPD	1,144	0.6%	1,144	3.0

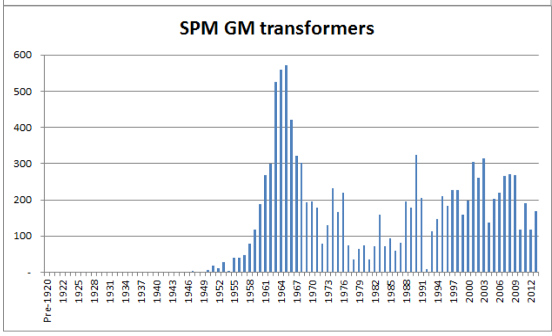
We have approximately 85,000 ground mounted and pole mounted transformers.

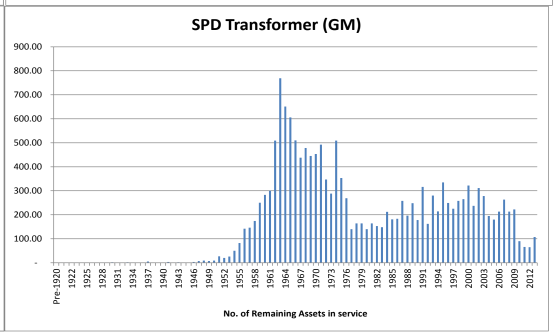
Our strategy for HV transformers is based on:

- *Replacement of ground mounted transformers alongside RMUs where condition or where physical constraints requires it.*
- *In addition, replacing pre-1962 GM transformers for losses reduction*
- *Refurbishing transformers where possible for re-use*
- *Replace on failure - pole mounted and ground mounted HV Transformers*









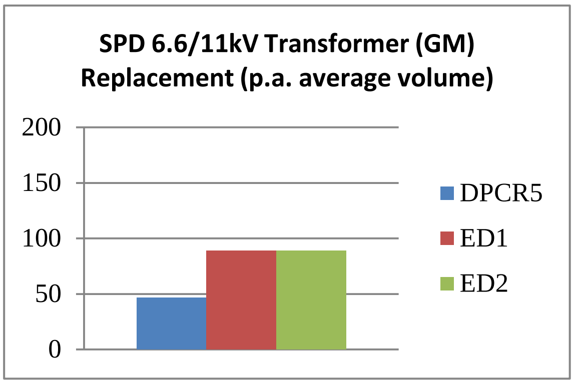
The above age profiles highlight the population of both ground mounted and pole mounted transformers installed in the 1960s.
Currently we have 11,290 ground mounted units in SPM and 16,268 in SPD and we intend to replace 7.5% and 4.4% during ED1 respectively. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

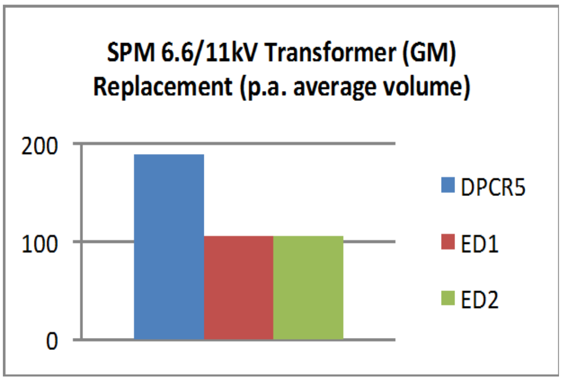
We have 33,105 pole mounted units in SPM and 25,060 in SPD and we intend to replace 4.6% in both licences during ED1 respectively. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

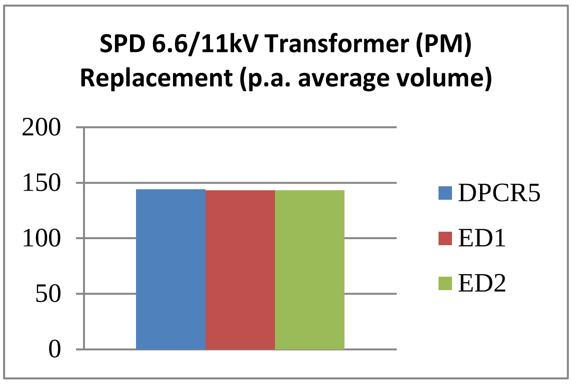
Comparing ED1 to DPCR5

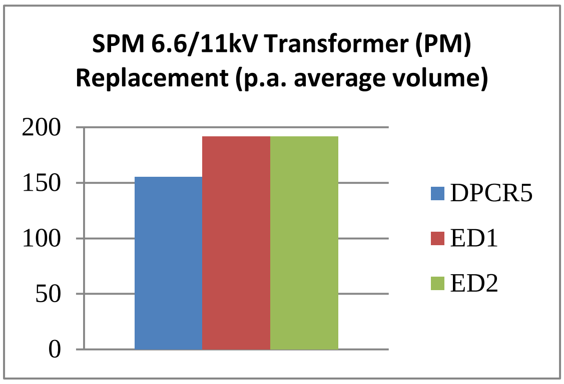
Asset Replacement, Refurbishment		DPCR5		RIIO-ED1		
		D5 pa £m	Total £m	ED1 pa £m	Total £m	% change
11kV Secondary Transformer Replacement	SPD	1.0	5.0	1.2	9.9	24%
	SPM	1.5	7.4	1.6	13.1	10%
11kV Secondary Transformer Refurbishment	SPM	0.1	0.5	0.8	6.3	N/A
Total	SPEN	2.6	12.9	3.6	29.3	38%

These profiles demonstrate our ongoing strategy of replacing units based on condition and loss reduction.





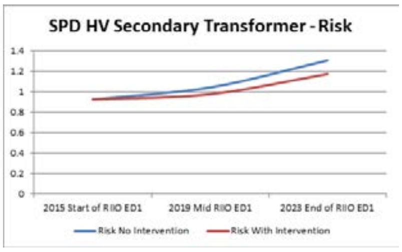




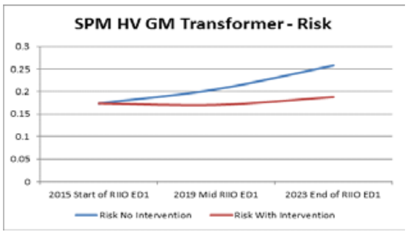
Asset Health and Criticality Indices

The net movements in our HI and CI ratings over ED1 for our HV ground mounted transformers are shown in the following tables. We do not include HV pole mounted transformers in our HI and CI assessment processes.

SPD	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	264	0	0	0	-264	0
CI2	241	0	0	0	-241	0
CI3	139	0	0	0	-139	0
CI4	70	0	0	0	-70	0
Total HI	714	0	0	0	-714	0



SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	424	319	319	-638	-424	0
CI2	233	175	175	-351	-233	0
CI3	133	100	100	-200	-133	0
CI4	55	41	41	-83	-55	0
Total HI	845	636	636	-1272	-845	0



Cost Benefit Analysis

We have considered a number of options for 11kV GM and 11kV PM transformer investment and the summary outcome is shown below. Further detail is provided in the ANNEX C6 Cost Benefit Analysis reference 1.1, 1.2 and 7- SPEN.

SPD GM Transformers

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Replace HV distribution transformers driven by ED1 RMU programme only	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	On top of baseline target high loss units (pre 1962) out with RMU programme based on load	Adopted	Most economic option	-£0.24	£0.60	£1.26	£1.92
3	On top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of delivery constraint	-£1.29	£1.23	£3.22	£5.20

SPM GM Transformers

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Replace HV distribution transformers driven by ED1 RMU programme only	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	On top of baseline target high loss units (pre 1962) out with RMU programme based on load	Adopted	Most economic option	-£0.44	-£0.01	£0.33	£0.67
3	On top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of delivery constraint	-£1.40	-£0.32	£0.55	£1.41

6.6kV/11kV Transformers (PM)

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Replace pole mounted transformers with new transformers when off-line rebuilding overhead lines	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	Replace pole mounted transformers with refurbished transformers	Adopted	Most economic option	£2.75	£2.48	£2.09	£1.94
3	Allow pole mounted transformers on refurbished lines to run to failure	Rejected	Marginally better NPV but rejected for customer service implications of multiple outages	£2.66	£2.31	£2.19	£2.23

Manweb Company Specific Factors

We incur additional costs in procuring HV ground mounted transformers suitable for use with our X-type RMUs. These incremental costs have been identified within our Company Specific Factors assessment for the SPM urban interconnected network.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
HV Non Load (11 & 6.6kV) Investment				
X- type secondary transformer asset replacement	CV3	48	£ 0.17	Based on ED1 plan to replace 281 X-type HV GM secondary transformers, these have discrete SPM components and costs. Cost differential based on delivering same volume at SPM Y-type HV GM transformer unit cost with efficiency.

8.3.4.2. 33kV and 132kV Transformers

Our Plan

33kV and 132kV transformer replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	110	1.5%	110	43.2
SPD (33kV only)	61	1%	61	15.6

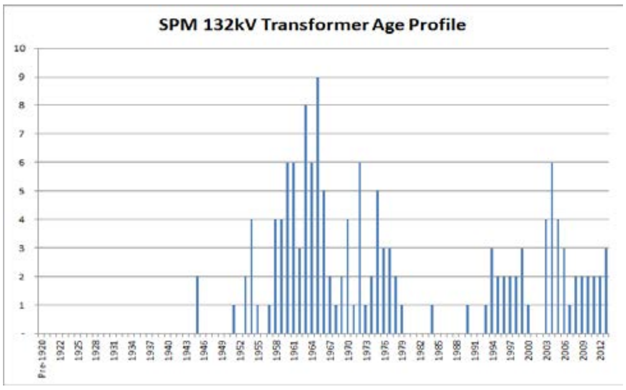
33kV and 132kV transformer refurbishment			
Licence	RIIO ED 1 Assets Refurbished	Average Population Refurbished (% per annum)	RIIO ED 1 Expenditure (£m)
SPM	64	0.8%	3.3
SPD (33kV only)	85	1.5%	3.7

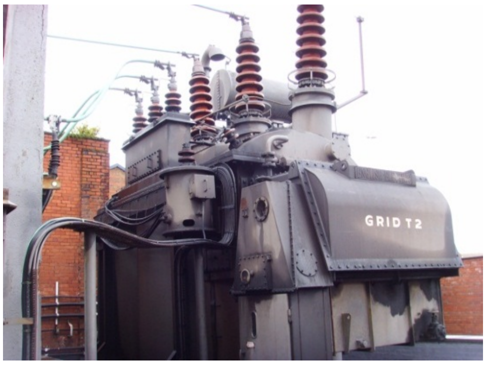
Although grid and primary transformers are generally reliable and our network operates with built in redundancy, the consequence of failure is significant as they supply large numbers of customers and replacement timescales are typically very long. The lead time on the manufacture of one of these large transformers can be up to 12 months.

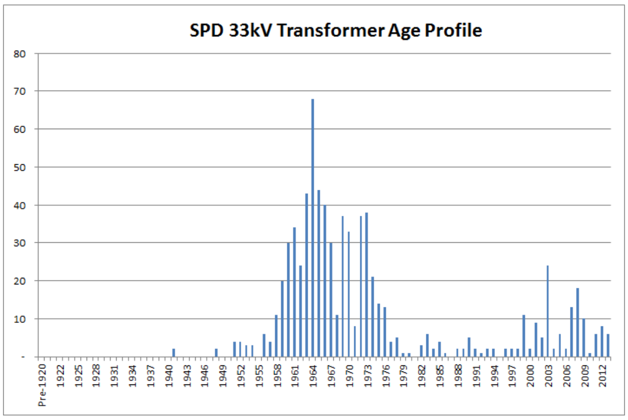
Our strategy is to identify end of life transformers and replace them before they fail. We have developed a detailed and effective testing regime which monitors the degradation of the internal components of the transformer. We also forensically examine faulted and replaced transformers to establish remaining life and validate our replacement strategy. Replacing large power transformers upon failure is not considered a viable strategy due to the potential impact of a catastrophic failure on the public, our staff, the environment and the network.

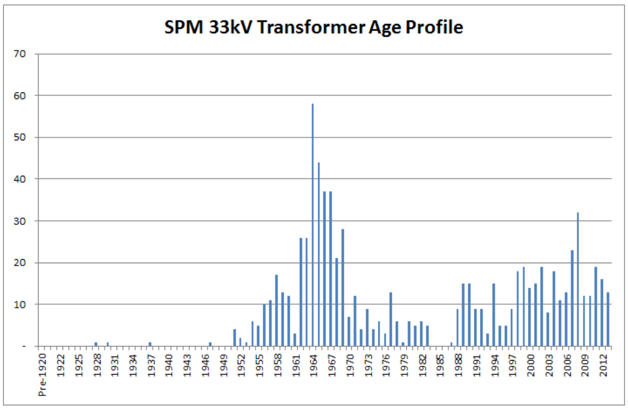
Our transformer population is ageing, and our modelling indicates a peak in replacement investment will be required in the next 10 to15 years. To manage this over the longer term and to extract maximum value from our existing assets, we have introduced a programme of mid-life refurbishment targeted at delivering a life extension of up to 20 years on suitable transformers to complement the replacement programme. Mid-life refurbishment is suitable for assets whose internal condition is adequate but whose external condition and that of some of the components have deteriorated.

Our refurbishment and replacement plans have been prioritised through site surveys, extensive chemical analysis of the insulation oil (which provides information on the internal condition, potential insulation degradation or electrical discharges) and through condition assessment.









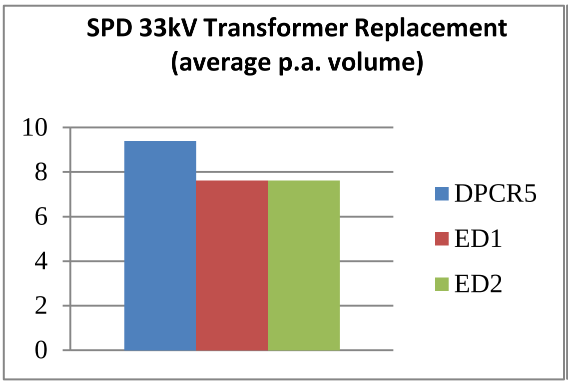
33kV transformer

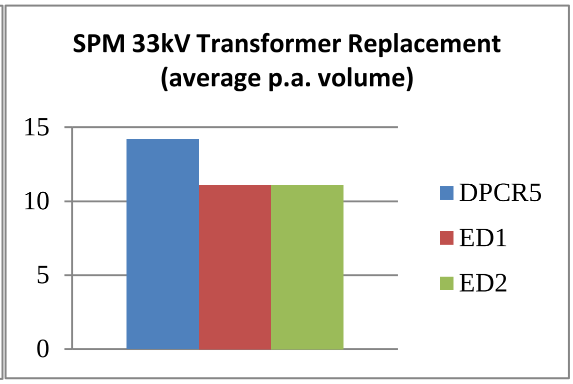
The age profiles highlight the high volume of assets installed in the 1950s and 1960s.

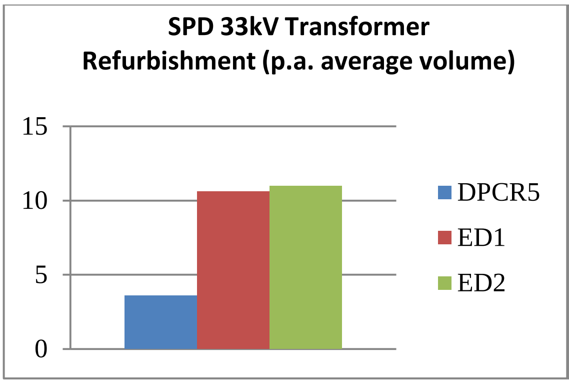
Currently we have 809 33kV transformers in SPM and 756 in SPD and we intend to replace 11% and 8.1% during ED1 respectively. We also intend to refurbish 5.9% in SPM and 11.8% in SPD during ED1. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

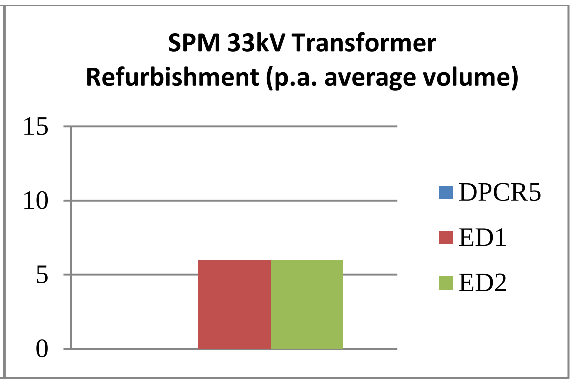
We have 144 132kV transformers in SPM and we intend to replace 14.6% during ED1 and refurbish 11.1%. Our replacement plan from DPCR5 to the end of ED2 is summarised in the chart below.

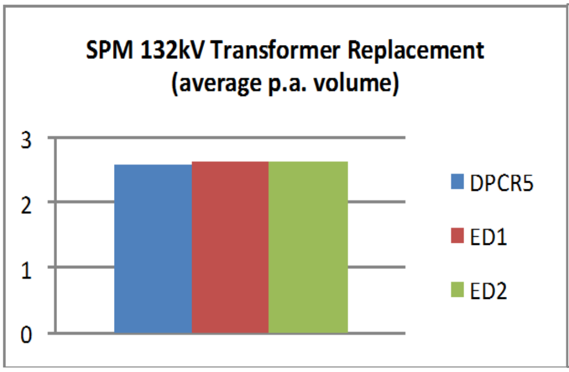
Comparing ED1 to DPCR5

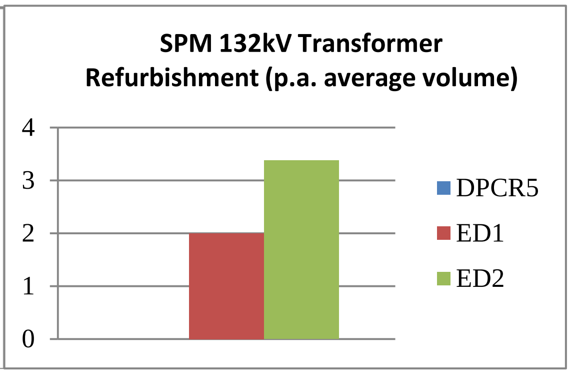












The combination of replacement and refurbishment allows us to effectively manage network risk and smooth the profile of transformer investment over the ED1 and ED2 periods. Our replacement plan is lower than delivery volumes achieved during DPCR5 but will be complemented by higher refurbishment volumes.

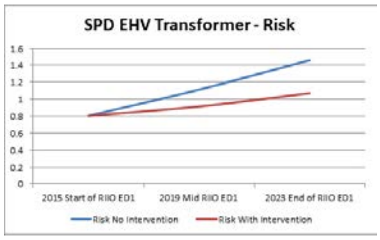
Grid/Primary Transformers		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
132kV Transformer Replacement	SPM	2.6	13.2	3.5	27.8	31%
132kV Transformer Refurbishment	SPM	0.0	0.0	0.2	1.5	N/A
33kV Transformer Replacement	SPD	2.4	11.8	1.9	15.6	-18%
	SPM	2.0	9.8	1.9	15.4	-2%
33kV Transformer Refurbishment	SPD	0.2	1.2	0.5	3.7	N/A
	SPM	0.0	0.0	0.2	1.7	N/A
Total	SPEN	7.2	36.1	8.2	65.8	14%

Impact on Health and Criticality Indices

The net movements in our HI and CI ratings over ED1 for our 33kV and 132kV transformers are shown in the following tables. Our replacement health will move from HI5 to HI 1, and our refurbishment health will move from HI4 to HI2.

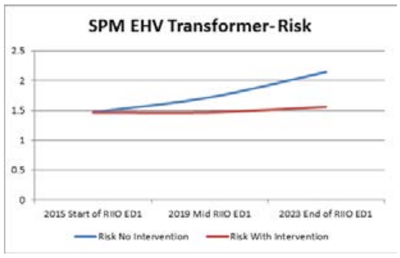
SPD 33kV transformers – HI/CI ED1 movements

	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	26	31	0	-31	-26	0
CI2	25	32	0	-32	-25	0
CI3	6	18	0	-18	-6	0
CI4	4	4	0	-4	-4	0
Total HI	61	85	0	-85	-61	0



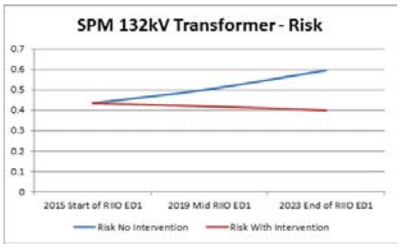
SPM 33kV transformer– ED1 HI/CI movements

SPM	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	45	22	0	-22	-45	0
CI2	29	19	0	-19	-29	0
CI3	15	7	0	-7	-15	0
CI4	0	0	0	0	0	0
Total HI	89	48	0	-48	-89	0



SPM 132kV transformer– ED1 HI/CI movements

	HI1	HI2	HI3	HI4	HI5	Total CI
CI1	10	5	0	-6	-9	0
CI2	7	6	0	-6	-7	0
CI3	4	2	0	-2	-4	0
CI4	0	3	0	-3	0	0
Total HI	21	16	0	-17	-20	0



Cost Benefit Analysis

We have used CBA analysis to inform the optimal deployment of refurbishment within our 33kV and 132kV transformer investment programmes. Our CBAs are included in our ANNEX C6 – Cost Benefit analysis reference no's 63, 64.1 and 64.2.

132kV Transformers

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Allow transformers to degrade until replacement required	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	On-site refurbishment	Adopted	Most economic option	£3.50	£2.75	£2.28	£1.70
2.1	Sensitivity: 80% higher refurbishment cost	Rejected	Rejected as lower NPV	£2.78	£1.84	£1.24	£0.52

SPD 33kV Transformers

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Allow transformers to degrade until replacement required	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	On-site refurbishment	Adopted	Most economic option	£3.11	£4.38	£4.56	£3.81
2.1	Sensitivity: 80% higher refurbishment cost	Rejected	Rejected as lower NPV	£1.45	£2.24	£2.10	£1.03

SPM 33kV Transformers

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Allow transformers to degrade until replacement required	Rejected	Rejected as not the best NPV option	£0.00	£0.00	£0.00	£0.00
2	On-site refurbishment	Adopted	Most economic option	£1.46	£2.39	£2.12	£1.53
2.1	Sensitivity: 80% higher refurbishment cost	Rejected	Rejected as lower NPV	£0.35	£0.48	-£0.20	-£0.98

Manweb Company Specific Factors

The SPM urban interconnected network design requires a proportionately larger number of primary transformers compared to traditional radial networks. The incremental cost of this has been included in our Company Specific Factors assessment.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Primary transformer asset replacement	CV3	83	£ 5.65	Based on ED1 plan to replace 89 x 7.5MVA transformers in ED1 @ £181k unit cost, typical radial system could satisfy same MVA capacity with 37 x 12/24MVA transformers @ £265k each. = £6.3m with efficiency =£5.56m

8.3.5. Protection Refurbishment

Our Plan

Protection refurbishment		
Licence	RIIO ED 1 volume refurbished	RIIO ED 1 Expenditure (£m)
SPM	1,846	14.1
SPD	1,021	8.1

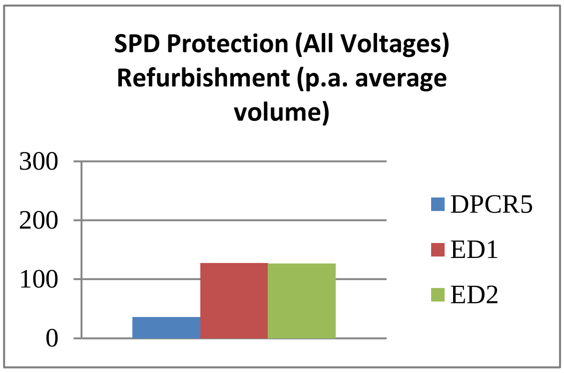
Protection equipment installed in our substations is necessary to ensure compliance with our legal obligations and maintain the integrity and safety of the main electrical plant and circuits. Protection detects fault on the network and clears them by operating substation circuit breakers designed to disconnect faults. Without protection equipment in good working order, network faults would not be promptly disconnected which would cause damage to equipment and potentially danger to the public. Other issues caused by inadequate protection include degraded network performance and stability and increased interruptions to customers.

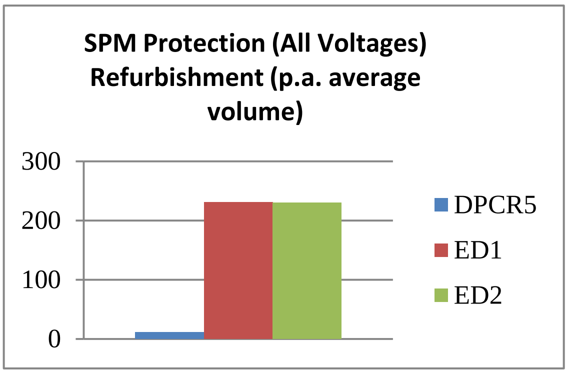
The preferred and most efficient approach, wherever possible, is to align protection modernisation with plant modernisation works. When plant modernisation work is being completed on the network, we will target the modernisation of remote end protection ends which are nearing end of life. This forms the majority of the investment programmes with smaller levels of investment in standalone protection modernisation that has been identified for equipment nearing end of life. Protection equipment targeted for replacement are selected on the type of the main protection relay and focuses on key factors such as reliability, supportability, compliance with policy and maintenance requirements.

For further information please refer to ANNEX C6 - Protective Equipment and Associated Systems Strategy - SPEN.

Comparing ED1 to DPCR5

We have increased our protection modernisation rates from DPCR 5 into ED1 and we plan to continue refurbishing our protection systems at the current rate in ED2.





Protection		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Protection Modernisation	SPD	0.2	0.8	1.0	8.1	400%
	SPM	0.5	2.4	1.8	14.1	265%
Total	SPEN	0.7	3.2	2.8	22.2	300%

Manweb Company Specific Factors

The SPM urban interconnected network requires substantially more protection equipment compared to conventional radial networks. The incremental cost of modernising this extra equipment has been taken into account in our Company Specific Factors assessment.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Protection modernisation	CV5	37	£4.38	Based on ED1 plan to modernise remote end protection inline with Primary substation switchgear replacement programme. Cost differential based on removing these assets from plan. Costs at Grid sites and Primary Transformer excluded from SPM RF case.

8.3.6. UG and OHL Pilots

Pilot cables are installed on overhead lines or buried underground. They are used for applications such as protection and remote control of our network assets.

For further information please refer to ANNEX C6 - Protective Equipment and Associated Systems Strategy - SPEN.

Our Plan

Pilot Wire Overhead				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure
SPD	18	1%	18	0.4
SPM	84	1%	81	1.5

Pilot Wire Underground				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure
SPD	72	0.3%	72	6.2
SPM	77	0.1%	81	7.4

Comparing ED1 to DPCR5

Pilots		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
UG & OHL Pilots	SPD	1.2	5.9	0.8	6.6	-31%
	SPM	1.0	4.8	1.1	8.9	15%
Total	SPEN	2.2	10.8	1.9	15.5	-10%

We plan to increase investment levels during ED1 order to address deteriorating UG and OHL copper pilot cable assets and end of life OHL fibre systems. We will also complete the programme to remove outdated fibre wrap pilots from our network that was started in DR5.

Manweb Company Specific Factors

The SPM urban interconnected network requires substantially more pilot cables compared to conventional radial networks. The incremental cost of modernising this extra equipment has been taken into account in our Company Specific Factors assessment.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Unit protection pilot wires 'hardex' overhead and underground cables	CV3	103 & 104	£3.23	Based on ED1 plan to replace to replace 70km of poorly performing protection underground pilots and 25 end of life 'Hardex' pilot cables on the overhead network. Cost differential based on SPD costs and volumes as a proxy for Traditional Industry pilot expenditure.

Cost Benefit Analysis

We have considered a number of options for pilot cable investment and the summary outcomes are shown below. Further detail is provided in the ANNEX C6 - Cost Benefit Analysis reference 9 – SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Reactive Investment - Repair (on discovery)	Rejected	Rejected as lower NPV	£0.00	£0.00	£0.00	£0.00
3	Proactive testing and repair of degraded assets (inc short section replacements)	Adopted	Most economic option	£0.57	£1.22	£1.98	£3.44
3.1	10% increase in failures plus 5% reduction in repair rates	Rejected	Rejected as negative NPV	-£0.20	-£0.27	-£0.31	-£0.31
4	Installation of basic monitoring and increased investment made to repair discovered faults	Rejected	Rejected as lower NPV	-£0.06	£0.51	£1.25	£2.73

8.3.7. Batteries at HV, 33kV and 132kV Substations

Our Plan

Battery replacement				
Licence	RIIO ED 1 Assets Removed	Average Population Removed (% per annum)	RIIO ED 1 Assets Added	RIIO ED 1 Expenditure (£m)
SPM	7,517	12.1%	7,517	3.5
SPD	648	2.1%	648	1.0

Battery systems are a critical component of the protective equipment used to promptly disconnect faults from the network. If batteries are not in good working order, the operation (tripping) of devices used to disconnect faults from the network cannot be completed, causing equipment damage and potentially danger to staff and the public.

Batteries age and their performance deteriorates rapidly as they reach end of life. They therefore need to be replaced before end of life due to their criticality. Investment is also needed to replace obsolete, unsupportable battery chargers and to modernise chargers to ensure continued performance where possible.

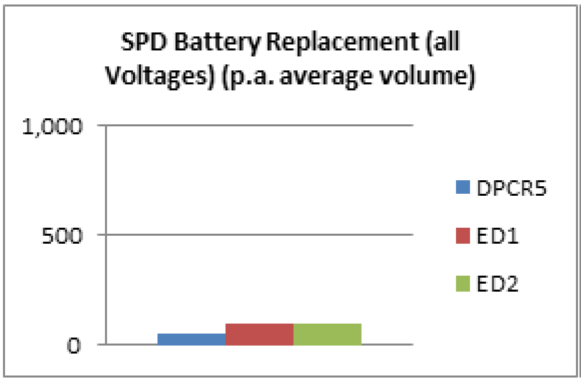
Investment in battery modernisation will continue in ED1 and upgrading of many of our primary and grid battery systems will also be achieved through the Black Start resilience initiative.

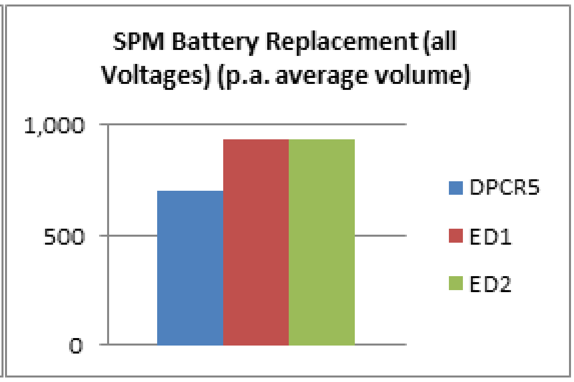
Currently we have 7,715 batteries in SPM and 3,918 in SPD and we intend to replace 97% and 19.3% during ED1 respectively. The high figure in SPM is due to the large proportion of HV substations as the life of HV substation batteries is typically only 6 years and we will therefore need to replace all of them during the 8 years of ED1. Our replacement plan from DPCR5 to the end of ED2 is summarised in the charts below.

For further information please refer to ANNEX C6 - Protective Equipment and Associated Systems Strategy - SPEN.

Comparing ED1 to DPCR5

Battery replacement from D5 through ED1 to ED2 continues at similar levels due to the relatively short lifespan of these assets.





Batteries		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Batteries Replacement	SPD	0.1	0.6	0.1	1.0	3%
	SPM	0.5	2.3	0.4	3.5	-5%

Manweb Company Specific Factors

The SPM urban interconnected design requires considerably more substations and associated protection systems. This has a consequent requirement for additional battery systems over a conventional radial design.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
HV Non Load (11 & 6.6kV) Investment				
Secondary substation battery replacement	CV3	51	£ 1.01	Based on ED1 plan to continue to replace X-type secondary substation batteries on a 6 year rolling programme, these are discrete SPM components. Cost differential based on SPD volumes and unit cost for HV substation battery replacement as proxy for Traditional Industry design requirement

8.3.8. Civil Works

Our Plan

Civil works driven by condition of civil items (Excluding LV Street Furniture)		
Licence	RIIO ED 1 Activity volume	RIIO ED 1 Expenditure (£m)
SPM	6,204	48.6
SPD	4,535	35.3

Ensuring our civil structures and buildings are kept in good condition is of vital importance, as they are key to maintaining safe and secure sites to protect both members of the public and our staff.

A large proportion of our electrical assets are designed for indoor use and therefore are susceptible to poor environmental conditions, which can reduce performance, cause failures and lead to excessive life time costs. Ensuring the substation environment is kept warm and dry maximises the operational life of our electrical equipment.

In DPCR5 we carried out a comprehensive programme of detailed civil surveys to catalogue the condition and necessary remedial costs associated with our grid and primary substations. The surveys were carried out by civil engineering specialists.

For further information please refer to our ANNEX C6 - Civil Strategy and Plans - SPEN.

The result of the surveys provided an overall health index of each substation that has been derived from the individual assessment of all key civil and structural elements that make it up. Depending on the size of the substation between 10 and 200 civil structural assets have been assessed and recorded.

Secondary substation civil investment is based on our understanding of historical investment in the main components including doors, roofs and fences and clearance of civil defects. We plan to extend our HI approach to secondary substations in line with our Grid and Primary methodology.

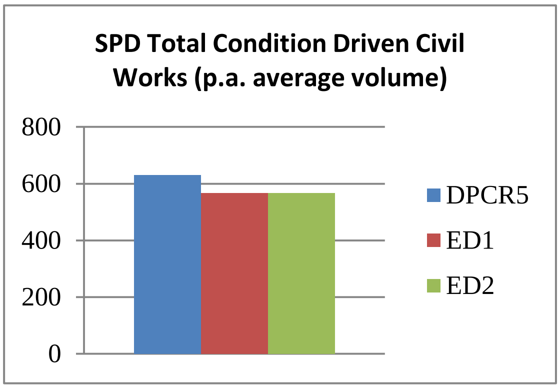
Substation support structure

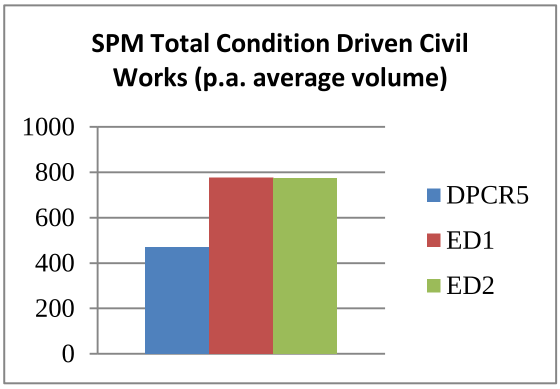
Primary substation building

Comparing ED1 to DPCR5

We plan to reduce our overall level of investment in SPD; this is predominately due to a reduction in the level of required investment at our HV substations. In SPM we will increase the level of spend from DPCR into ED1 which is driven by our extensive civil condition surveys of our 132kV & 33kV substations.

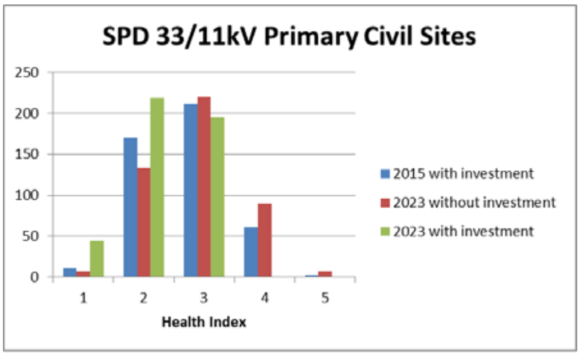
Beyond ED1 we intend maintain similar levels of investment in civil condition as illustrated in the graph below. This continued level of investment will ensure the life of our electrical assets is maximised.

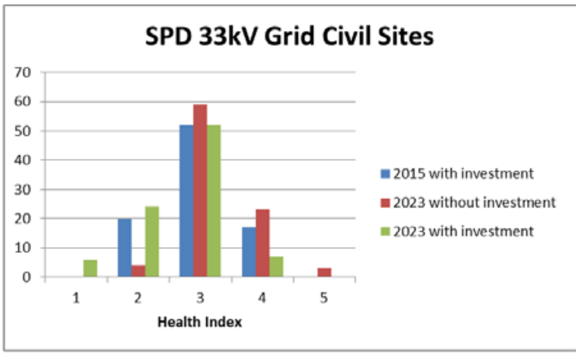


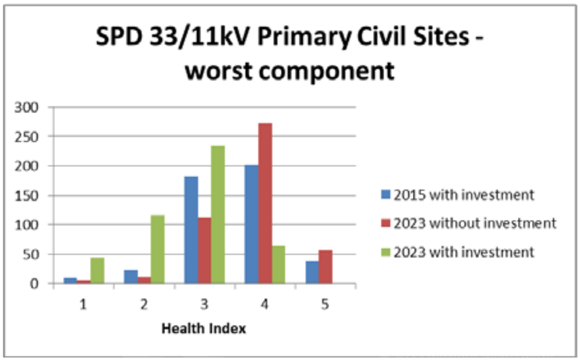


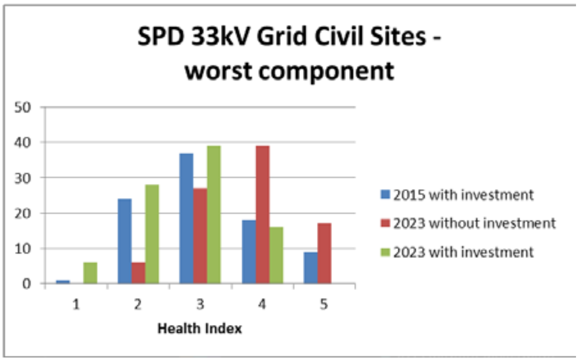
Asset Health and Criticality Indices

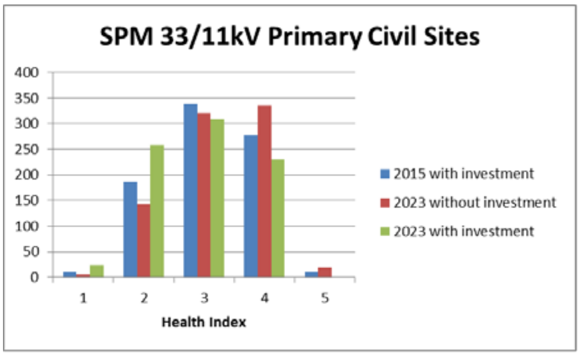
During DPCR5 we have developed HI for Civil assets at grid and primary substations. We have an HI for each individual element and one for the substation as a whole. This allows us to target investment at the poor condition structures at sites where we are also doing plant replacement. We also have a programme tackling the worst individual civil assets at sites where no other work is taking place. The impact of our investment in RIIO-ED1 is illustrated in the health index movement graphs below.

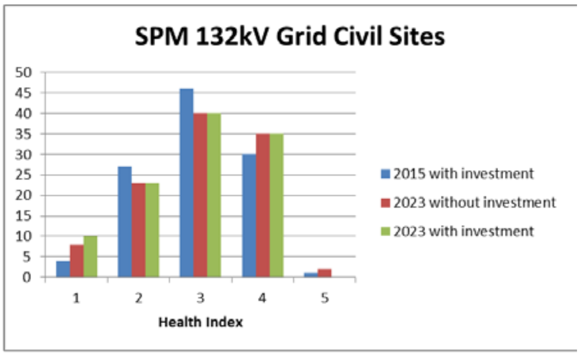


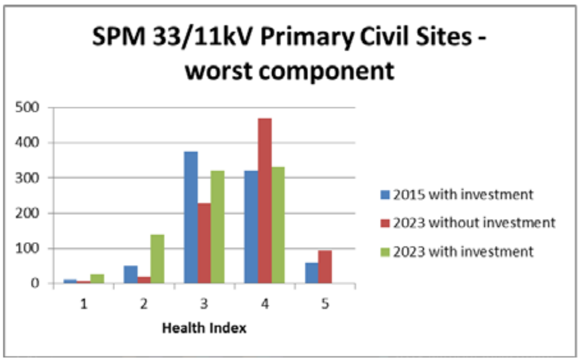


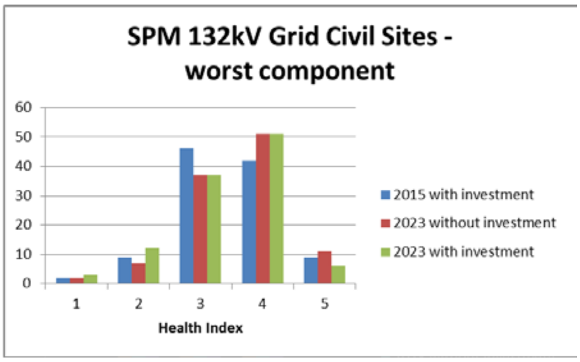












Cost Benefit Analysis

We have considered a number of options for 11kV substation civil investment and the summary outcomes are shown below. Further detail is provided in the ANNEX C6 - Cost Benefit Analysis - reference 51.1 and 51.2 - SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Carry out civil programme based on key investment activities	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	As above but do not replace roofs in ED1	Rejected	Rejected as negative NPV	-£2.04	-£2.93	-£3.77	-£5.13

We have considered a number of options for 33kV substation civil investment and the summary outcomes are shown below.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	Renew/Refurb HI 4/5 civil assets and ensure the substation is safe and secure	Adopted	Most economic option	£0.00	£0.00	£0.00	£0.00
1	Renew//Refurb all assets showing signs of decay and ensure the substation is safe and secure	Rejected	Rejected as negative NPV	-£4.50	-£5.75	-£6.59	-£7.46
2	As per the baseline option, however deferral of substation roof replacement during ED1.	Rejected	Rejected due to negative NPV	-£3.33	-£4.45	-£5.36	-£6.60

Manweb Company Specific Factors

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Substation civil works	CV6	16	£ 6.34	Based on ED1 plan to secure and modernise our 33kV Substation assets. SPM have greater volumes than Traditional industry standard including unit requirement for RMU enclosures. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
HV Non Load (11 & 6.6kV) Investment				
Secondary substation civils	CV6	6,7,8,9,(14 &15)	£ 10.13	Based on ED1 plan to secure and modernise our HV Substation assets. SPM have greater volumes than Traditional industry standard including unit requirement for RMU enclosures. Cost differential based on SPD volumes and unit cost as proxy for traditional industry design requirement

8.3.9. Operational Information Technology and Telecoms

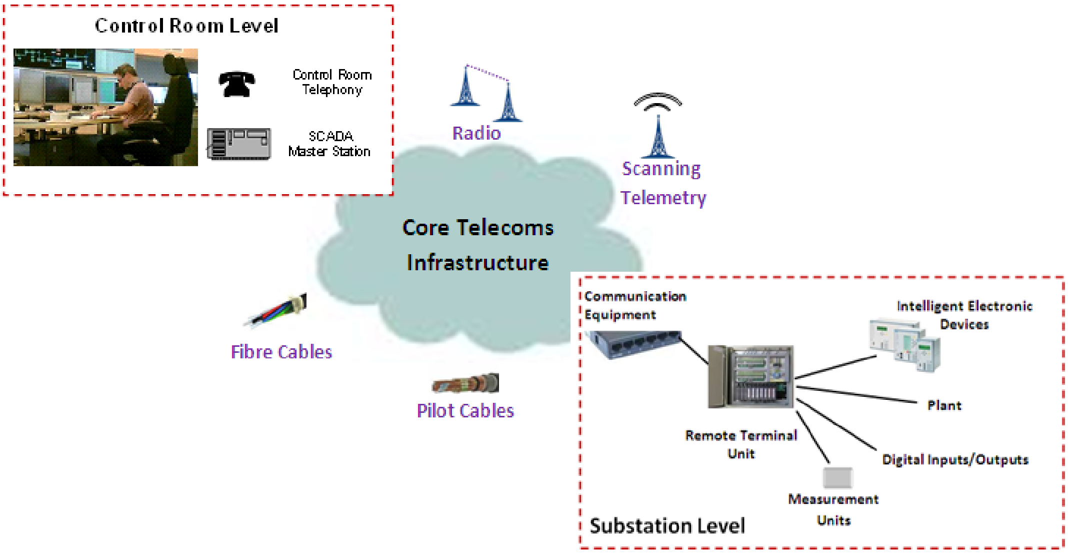
Our Plan

Expenditure (£m)			
Licence	Substation RTUs, Marshalling Kiosks, Receivers	Communications for Switching and Monitoring	Control Centre Hardware and Software
SPM	14.8	13.8	3.4
SPD	7.7	8.8	3.2

This investment is required to maintain and develop our real time control systems and telecommunications equipment which are fundamental to the safe and efficient operation of our network. Further details can be found in ANNEX C6 – Operational IT & Telecoms Strategy – SPEN.

These systems enable us to monitor network loads, alert us to when equipment operates and to highlight conditions where we need to take action to manage the power network. They provide the means to remotely control plant and reconfigure the network proactively and reactively.

Remote operation is necessary for us to efficiently manage the network continuously and especially during storm situations to provide prompt restoration of supplies which is the number one priority of our customers.



Substation RTUs, Marshalling Kiosks, Receivers

Investment activities in the ED1 period will include replacement programmes for end of life Grid and Primary substation Remote Terminal Units (RTUs), secondary control systems and monitoring equipment.

The biggest investment activity in this area is replacement of Grid (SPM only) and Primary RTUs which represents 87% of the Operational and IT investment in SPM and 71% in SPD.

RTUs are electronic devices deployed at network substations to collect plant indications, alarms and measured network loads and send this information through our communications network to the central control system where it is displayed on a central system to allow the operator to understand what is happening in real time at each site. Crucially, these devices also process requests from the control centre to operate plant remotely.

The majority of our RTUs were installed in the early to mid 1990s with a 15-20 year asset life expectancy. We will far surpass that by efficient management of the equipment, but now need to accelerate replacement in ED1, completing in the early years of ED2.

Control Centre Hardware and Software

Whilst RTUs are essential to the control and operation of individual sites, the central control system gathers data from RTUs and presents this information to operators allowing them to quickly understand the behaviour on the network and act accordingly. The central control system also allows operators to send requests to all remotely controllable equipment connected to the systems.

This is a technology area where change is rapid, both in term of vendors obsolescing products and withdrawing support at the same time as user requirements changing due to evolution of the network and introduction of products on the network (plant & protection) which provoke changes to control system functionality.

Our investment plan is detailed in ANNEX C6 – Operational IT & Telecoms Strategy – SPEN. and contains the following elements:

- *Annual Updates to Central System Software*
- *Investment in Hardware and Control Centre Infrastructure*
- *Full Upgrade of the Central System*
- *Data Servers and Software Modernisation*
- *Control Centre Modernisation*

Communications for Switching and Monitoring

All the benefits control systems afford to our customers are only possible with effectively managed telecoms infrastructure. Parts of the same communications infrastructure are used for protection and so are critical to maintaining network performance levels and limiting danger to our staff and the public.

The volume of information coming from the network will increase through ED1, placing additional demands on the telecoms systems. Increasing network service requirements are the main driver for an extensive communication networks update commencing in ED1 and completing in ED2. The telecoms network update will greatly aid the Smart Grid transition as it will be possible to provide communications for new applications readily on the new infrastructure.

Scanning telemetry is used widely for delivery of communication signals to primary substations. The associated RTU equipment is unsupportable and unreliable. We began replacement in DPCR5 and this will continue in ED1.

Comparing ED1 to DPCR5

Operational IT & Telecoms		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Substation RTU's, Marshalling Kiosks and Receivers	SPD	0.2	0.9	1.0	7.7	409%
	SPM	0.3	1.6	1.8	14.8	484%

The increase in spend recognises the end of life and obsolete RTUs which need to be replaced in ED1.

Operational IT & Telecoms		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Control Centre Hardware and Software	SPD	0.9	4.3	0.4	3.2	-54%
	SPM	0.6	2.8	0.4	3.4	-24%

Operational IT & Telecoms		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
Communications for Switching and Monitoring	SPD	0.3	1.7	1.1	8.8	231%
	SPM	1.2	5.8	1.7	13.8	49%

Cost Benefit Analysis

We have considered a number of options for each of our Operational IT and Telecoms investment and the summary outcome are shown below.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Perform a hardware only refresh to avoid bathtub curve failure effects on existing systems	Rejected	Not the best cost/benefit option	£0.00	£0.00	£0.00	£0.00
2	Modernisation Option A	Adopted	Most economic option	£0.87	£1.86	£3.03	£4.51
3	Modernisation Option B	Rejected	Rejected as lower NPV	-£0.12	£0.21	£0.76	£1.32
4	Modernisation Option C	Rejected	Rejected as lower NPV	-£2.87	-£3.22	-£3.01	-£2.67

RTU replacement

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	New RTU solution customised to support legacy RTU protocols	Rejected	Not the best cost/benefit option	£0.00	£0.00	£0.00	£0.00
1	New RTU solution based on industry standard RTU protocols support	Rejected	Not the best cost/benefit option	-£1.29	-£1.39	£2.31	£5.51
2	New RTU solution based on industry standard RTU protocols support - Extended timescales for RTU population replacement (recovered RTUS used as spares)	Adopted	Most economic option	£5.35	£8.96	£14.37	£20.72
2.1	Sensitivity of CML Performance impact of investment deferral	Rejected	Rejected as lower NPV	£4.37	£7.68	£13.34	£19.43
2.2	Sensitivity of equipment replacement costs increase by 30% and CML Performance impact of investment deferral	Rejected	Rejected as lower NPV	-£1.52	-£1.42	£1.72	£3.84

Manweb Company Specific Factors

The SPM urban interconnected design requires considerably more substations and associated protection systems. This has a consequent requirement for additional system control and telecommunication infrastructure.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Operational IT associated with RTU replacement	CV105	6	£ 6.37	Based on ED1 plan to modernise ageing RTU infrastructure at 33kv primary substations. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement
Operational IT associated with Ethernet communications for switching & monitoring	CV106	7	£ 4.75	Based on ED1 plan to modernise ageing communications platform to improve data retrieval and monitoring at 33kv primary substations. Cost differential based SPD on volumes and unit cost as proxy for Traditional Industry design requirement

8.3.10. BT 21st Century (BT21CN)

Our Plan

Licence	Circuit Upgrades	Expenditure (£m)
SPM	192	28.3
SPD	34	5.0

SPM, and to a lesser extent SPD, currently have a high reliance upon leased copper BT services for critical protection applications. These services will be made obsolete by 2018 as part of BT's 21CN development and will be migrated to the new BT platform where the communications paths will no longer be suitable for protection applications.

Investment in BT21CN mitigation activity is set to ramp up significantly from DPCR5 spend in the first 3 years of ED1 in line with the closure of the BT21CN lease lines platforms in 2018. We have 192 circuits remaining in SPM and 34 circuits remaining in SPD which will require alternative solutions.

BT21CN mitigation work is essential to ensure protection is coupled with suitable communications otherwise the result will be degraded network stability, increased CI/CML performance and extended fault clearance time which will increase risk of damage to our and third party equipment and increase public safety risk.

SPM is the DNO worst affected by BT21CN, historically having the highest reliance upon leased line services of any of the UK DNOs, a cost recognised in our SPM specific factors case. For this reason, in DPCR5, BT21CN expenditure in SPM was reported as a High Value project (HVP) but with the HVP threshold change in ED1 to £50m, this programme no longer qualifies and is therefore forecast in the BT21CN table.

We have targeted mitigation of the lowest cost SPM and SPD BT21CN circuits in DPCR5. This strategy was deployed to minimise early investment should the BT leased line platform closure time be further extended and to safeguard against wasted investment should suitable cost effective alternatives emerge. Currently, OFCOM publications on this subject confirm the transition to BT21CN platform will be complete in 2018.

Our BT21CN mitigation strategy is based on utilisation of a ‘toolbox’ approach where least cost solutions have been selected on a circuit by circuit basis and all opportunities to utilise the most efficient solutions have been explored. This is demonstrated by the efficiency of our unit costs to date compared to others with similar requirements in the industry.

Mitigation solutions considered include BT fibre services (which will have adequate performance post-BT21CN), radio solutions and our own fibre infrastructure. Further details can be found in Annex C6 - BT21CN Mitigation Strategy - SPEN.

Comparing ED1 to DPCR5

BT21CN Mitigation		DPCR5		RIIO-ED1		% change
		D5 pa	Total	ED1 pa	Total	
		£m	£m	£m	£m	
BT21CN	SPD	0.4	1.9	0.6	5.0	62%
	SPM	2.0	9.9	3.5	28.3	79%
Total		2.4	11.8	4.2	33.2	76%

This step up in expenditure from DPCR5 to ED1 reflects the strategy set out in line with Ofgem guidance at the start of DPCR5 to complete the more straightforward circuits first in DPCR5 leaving more complex and expensive circuits for ED1.

For further information please refer to ANNEX C6 - BT21CN Mitigation Strategy - SPEN.

Cost Benefit Analysis

We have considered two options for BT21CN investment and the summary outcomes are shown below. Further detail is provided in the ANNEX C6 - Cost Benefit Analysis ref 65 - SPEN.

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
Baseline	All leased services solution	Rejected	Not most economic option	£0.00	£0.00	£0.00	£0.00
1	All Private Network Solution	Rejected	Least economic option	-£11.87	-£18.03	-£23.88	-£32.31
2	Cost Effective Mix of Private Network and Baseline BT Services	Adopted	Most economic option	£2.76	£2.93	£2.83	£2.42

Manweb Company Specific Factors

As explained above, SPM is the licence most affected by BT21CN given its greater dependence of BT leased line services to provide communications for the large number of protection circuits associated with the interconnected network. We have accounted for the incremental cost in our company specific factors assessment.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
BT 21CN communications channel replacement	CV10	6	£ 23.22	Based on ED1 plan and BT requirement to replace copper communication circuits by end of 2018. SPM have greater dependency on these circuits for our unit protection systems. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement

8.3.11. Black Start

Our Plan

	Generators 72 hr run time	Batteries 72 hr capacity installed	Dc load disconnection & monitoring	Airwave Fixed & Mobile units	Expenditure (£m)
SPD	0	86	169	33	1.6
SPM	51	191	271	64	7.5

The UK power network is designed and operated to deliver an extremely robust supply to all connected customers. There are however circumstances through which the normal balance between connected generation and connected load can become disturbed, which if left unchecked can in the most extreme case result in the cascade loss of the entire or large portions of the UK network. Whilst considered rare, recent experience in both the USA and Europe have demonstrated that this is a credible risk. The recovery from this kind of event is termed ‘Black Start’.

The Government and the UK Electricity Industry consider that full restoration of the network to its normal operating state could take up to 72 hours. It is therefore a key requirement that all equipment on which the recovery process relies is made resilient for such a period, with the main considerations being remote control facilities, voice and data communications, and protection systems.

In order to accommodate the required level of Black Start resilience, we will invest to upgrade the battery systems or install back-up generation at our major sub stations to deliver meet this resilience requirement during ED1 at our grid and primary sites in SPM and primary sites in SPD. Black Start expenditure in the SPD area is less than SPM due to the 132kV network in Scotland being covered by the SP Transmission licence.

By undertaking black start enhancements at 52% of our primary sites in SPD and 57% of primary sites in SPM, we will achieve 100% of our targeted black start resilience. Where possible, the delivery of black start resilience will be incorporated with other substation works to ensure efficient and cost effective delivery.

We will also undertake work to extend resilience in our communications infrastructure including voice communications, where possible incorporating the work with our BT21CN programme.

Comparing ED1 to DPCR5

Our Black Start programmes are targeted to commence in ED1, hence no costs allocated in D5.

<table>
<tr><th colspan="2" rowspan="3">Substation Resilience</th><th colspan="2">DPCR5</th><th colspan="3">RIIO-ED1</th></tr>
<tr><th>D5 pa</th><th>Total</th><th>ED1 pa</th><th>Total</th><th rowspan="2">% change</th></tr>
<tr><th>£m</th><th>£m</th><th>£m</th><th>£m</th></tr>
<tr><td rowspan="2">Black Start</td><td>SPD</td><td></td><td></td><td>0.2</td><td>1.6</td><td></td></tr>
<tr><td>SPM</td><td></td><td></td><td>0.9</td><td>7.5</td><td></td></tr>
<tr><td>Total</td><td></td><td>0.0</td><td>0.0</td><td>1.1</td><td>9.0</td><td>100%</td></tr>
</table>

Cost Benefit Analysis

We have considered a number of options for Black Start investment and the summary outcomes are shown below. Further detail is provided in the ANNEX C6 - Cost Benefit Analysis ref no 3 - SPEN.

<table>
<tr><th rowspan="2">Option no.</th><th rowspan="2">Options considered</th><th rowspan="2">Decision</th><th rowspan="2">Comment</th><th colspan="4">NPVs based on payback periods</th></tr>
<tr><th>16 years</th><th>24 years</th><th>32 years</th><th>45 years</th></tr>
<tr><td>Baseline</td><td>Install generators at all locations</td><td>Rejected</td><td>Rejected as lower NPV</td><td>£0.00</td><td>£0.00</td><td>£0.00</td><td>£0.00</td></tr>
<tr><td>1</td><td>Generation applied to all Grid Sites consistent with SPT, 6 operational sites, plus 72hr battery capacity batteries in Primaries with Significant DC loading</td><td>Rejected</td><td>Rejected as lower NPV</td><td>£19.63</td><td>£26.89</td><td>£32.74</td><td>£40.17</td></tr>
<tr><td>2</td><td>As option 1 plus 72hr capacity battery capacity/dc load disconnection scheme applied to primary sites</td><td>Rejected</td><td>Rejected as lower NPV</td><td>£22.45</td><td>£30.57</td><td>£37.04</td><td>£45.15</td></tr>
<tr><td>4</td><td>Portfolio of solutions balanced risk</td><td>Adopted</td><td>Most economic option</td><td>£24.06</td><td>£32.62</td><td>£39.38</td><td>£47.81</td></tr>
</table>

Manweb Company Specific Factors

There is an incremental cost in meeting the substation resilience standards in SPM due to the large population of primary substations. This incremental cost has been included within our Company Specific Factors assessment.

SPM Company Specific Factors				
Category	CV table	Row No.	Incremental SPM Factor submission	Rationale
33kV Non Load Investment				
Black Start resilience associated with Primary substations	CV11	74	£ 0.91	Based on ED1 plan to make qualifying 33kv primary substations resilient for 72hrs. Cost differential based on SPD volumes and unit cost as proxy for Traditional Industry design requirement

8.3.12. Flood Mitigation

Our Plan

Licence	Number of sites	Expenditure (£m)
SPM	14	0.8
SPD	14	0.8

Over recent years across the UK, there have been incidents of flooding impacting on substations and resulting in loss of electricity supplies and our stakeholders have asked us to do more to try and mitigate the risk of flooding. Using information provided by the Environment Agency (EA) and the Scottish Environment Protection Agency (SEPA), we have identified substations that are at higher risk of flooding and in accordance with industry guidance, we have applied a different degree of flood prevention dependent on the potential impact to customers.

In response to stakeholder feedback, we substantially accelerated our investment plans to reduce the risk of flood related disruption to an additional 168,000 customers within the DPCR5 period. By the end of March 2015, all of our primary sites will be capable of withstanding at least a ‘1 in 100 year’ flood event.

During stakeholder events for ED1 it was made clear that customers felt that flood protection measures at substations were considered important due to changing weather conditions. We presented investment options on flood protection and 90% of those attending our SPM workshop and 82% at our SPD workshop agreed with our draft investment plans in this area. Customers in both licence areas rated this as one of the most supported investment options and there was also support from on-line stakeholders to do more.

The mitigation measures designed or installed to date have been to cater for a fluvial (river) or coastal risk as this was the only information available from EA and SEPA at that time. Following on from fluvial and coastal flood risk maps, both the EA and SEPA have recently published detailed pluvial (surface water) maps and we have plans to start mitigating this risk at a number of primary substation sites within DPCR5. This work will continue in ED1 for identified grid and primary substations.

In response to recent events where a small number of secondary substations were flooded, and have a high risk of repeat flooding, we have taken steps to mitigate the risk at these sites. During ED1 we will continue with the work to protect those secondary substations at a high risk of flooding.

Comparing ED1 to DPCR5

Flood Mitigation		DPCR5		RIIO-ED1		
		D5 pa £m	Total £m	ED1 pa £m	Total £m	% change
Flooding	SPD	0.3	1.6	0.1	0.8	-70%
	SPM	0.6	2.9	0.1	0.8	-83%
Total		0.9	4.5	0.2	1.6	-363%

The reduction in expenditure from DPCR5 to ED1 reflects the strategy to complete all the high risk Grid and Primary sites in DPCR5.

8.3.13. Critical National Infrastructure

Our Plan

Expenditure (£m)		
Licence	Substation security	Cyber security
SPM	1.9	1.0
SPD	-	1.0

Substation security

Some of our assets in SPM are critical to national security and we liaise with Government agencies to ensure that any potential threats and risks are assessed and mitigated. In circumstances where potential risks are identified we will enhance the security of our asset. This includes the installation of cameras, electric fences and alarm systems.

CNI Cyber Security

SCADA systems form part of the UK Critical National Infrastructure and by necessity are connected electronically via firewalls to the Corporate IT network and hence ultimately to the Internet. These systems allow remote operation of equipment which can switch customer supplies on and off and as a result, access to them must be guarded carefully.

Further investment will be needed in the ED1 period to meet and maintain best practice in this area. Investment will be made to install Intrusion Prevention systems and refresh hardware and software solutions to improve the defences we have in place to protect CNI Infrastructure.

8.3.14. Legal & Safety

Our Legal and Safety expenditure addresses the following issues:

- *Security and metal theft*
- *Overhead line safety defects*
- *Air Break Switch Disconnector conversion*
- *Safety around recreational sites*
- *Provision of earthing*
- *Fire protection*
- *Asbestos management*

For further information please refer to ANNEX C6 - Legal & Safety Strategy - SPEN.

Site Security and Metal Theft

Legal & Safety		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
General Security	SPD	0.2	0.9	0.4	3.1	106%
	SPM	0.6	2.9	0.4	3.5	-24%
Metal Theft	SPD	0.1	0.6	0.8	6.1	573%
	SPM	0.2	0.8	0.5	4.3	247%

Site security is key to the safety of the public and to the continued safe operation of our network.

The increase in metal theft seen over the last few years, from virtually zero to a peak of 509 incidents in a year, has made securing our substations ever more critical. We are investing in security solutions on a targeted geographical basis to defend against metal theft and interference. This includes investment in security doors, new padlock key systems, alarm systems and installation of CCTV and electric fences at high risk substations.

We work with local police forces following incidents and this has led to a number of arrests and prosecutions and we are also working proactively to prevent further incidents occurring, using a range of innovative surveillance and asset identification techniques. We are electronically mapping the location of thefts to spot local/regional trends when a theft occurs. We are undertaking public information campaigns on the dangers of entering and interfering with electrical equipment. Also, regular liaison with regional and national cross-industry taskforces ensures that we are abreast of the current trends and issues relating to metal theft and the legislative actions of Government to tackle the problem.

We are currently investing in a range of security solutions to target “high risk” geographical areas and combat metal theft and interference. We are increasing the protection of sites with an “Abloy” key suite, supplementing this with enhanced security measures such as security doors in place of traditional substation doors. Further to this we are fitting security alarm systems to all our primary substations.

When metal theft or vandalism occurs, there is a requirement to replace or repair the stolen or damaged assets. This can include replacement doors, fences and padlocks or replacement electrical equipment. In some cases this also requires a substantial environmental clean-up, due to oil being emptied from equipment in order to access the copper components inside.

Overhead Line Safety Defects

OHL Safety Defects		
Licence	RIIO ED 1 Defects Removed	RIIO ED 1 Expenditure (£m)
SPM	37,408	10.7
SPD	36,952	10.6

The ESQC Regulations require us to deal with safety related defects on our overhead line network. This includes the repair of stays, signage, insulators and anti-climbing guards.

In relation to these areas, the ESQCR requires the following:

- *Stay wires - all stay wires (except for stays on earthed metal structures) must be fitted with insulators where there are bare phase conductors.*
- *Safety notices, - there is a statutory requirement to ensure safety notices are clearly visible on all poles & towers carrying uninsulated live electrical plant and equipment.*
- *Insulators – an overhead line must be supported on insulators so as to prevent leakage to earth, so any defective insulators pose a risk and must be replaced or repaired.*
- *anti-climbing guards – there is a statutory requirement to have fit for purpose anti-climbing equipment on wood poles and steel towers.*

ABSD Remedial Works Programme (SPD only)

ABSD Remedial Works		
Licence	RIIO ED 1 Volumes	RIIO ED 1 Expenditure (£m)
SPD	150	0.4

The programme to modify or renew air break switches to allow them to operate with a hookstick continues. This follows a fatality associated with this type of switchgear on another DNO's network and applies to all pole mounted air break switch disconnectors (ABSDs) which have earthing systems fitted on the same pole as the switching location on both the 11kV & 33kV networks. We will have completed this work on our 11kV system by the end of DPCR5, leaving the 33kV network to be addressed in ED1.

Mural Wiring (SPM only)

Mural wiring		
Licence	RIIO ED 1 Properties modernised	RIIO ED 1 Expenditure (£m)
SPM	10,800	11.6

Urban mural wiring is a system of wiring employed in SPM where cables are fixed to the external fabric of buildings in towns and cities. The nature of the original installation of these particular systems has resulted in significant public safety issues and as a consequence, a programme to replace Mural Wiring is underway. In the main, mural wiring projects are individually designed and involve the installation of new LV mains and individual underground services to affected properties.

Safety Around Recreational Sites

Safety around recreational sites		
Licence	RIIO ED 1 sites	RIIO ED 1 Expenditure (£m)
SPM	112	2.4
SPD	112	2.3

Protecting the public from the dangers of inadvertent contact with overhead lines at fishing sites, caravan parks and recreational areas is also a key public safety concern. The solutions range from providing adequate warning signs to removing the hazard altogether by deviating the line out of the site or undergrounding the overhead line through the site. We do, however, recognise that excavating in these areas causes temporary disruption to the activities of members of the public and also to wildlife in the vicinity. Where it is appropriate to do so, we will deviate the overhead line out of the recreational area, thereby minimising the disruption caused by our work.

Provision of Earthing - Rise of Earth Potential (RoEP)

RoEP		
Licence	RIIO ED 1 Mitigation Works	RIIO ED 1 Expenditure (£m)
SPM	324	1.8
SPD	160	0.6

Schedule 4 of the Electricity Act 1989 sets out the obligations the Electricity Industry and Telecommunications Operators have to avoid interference between electrical plant and telecommunications apparatus.

We will routinely test earthing systems in ED1 in line with engineering recommendations. Sites in high resistivity areas are likely to have high impedance earth measurements and accordingly will be classified as “Hot” if there local earth potential rise exceeds defined thresholds. In such sites, special precautions are required for third party telecommunication services which terminate within a substation.

We must manage risks to third parties associated with earth potential rise outside the substation. We have identified sites at which risk potentially exists in high resistivity areas where third party developments have been constructed close to our substations.

We will undertake testing at 40 Grid substations in SPM, 120 SPD and 200 SPM Primary Substation Sites in ED1. Earthing will be improved where necessary and we project that only a small percentage of sites with require alterations to earthing systems.

Fire Protection

Fire protection		
Licence	RIIO ED 1 sites	RIIO ED 1 Expenditure (£m)
SPM	204	1.2
SPD	208	1.2

Understanding fire risk in our substations and implementing appropriate solutions are essential in ensuring public safety. Our fire protection policy defines the mitigation measures necessary to ensure compliance with our legal obligations to minimise public safety risk. One of the key areas of risk is basement and embedded substations where transformers and switchgear are housed below or adjacent to occupied offices or public buildings. Our proposals to mitigate risk include installing fire doors, provision of adequate ventilation, installation of low smoke zero halogen (LSZH) cables and retro filling transformers with an insulating medium less flammable than oil.

Considerable consultation has taken place with independent fire protection experts and local fire services to understand the risks and potential mitigation measures.

Asbestos management

Asbestos management		
Licence	RIIO ED 1 sites	RIIO ED 1 Expenditure (£m)
SPM	80	0.4
SPD	80	0.4

Asbestos in substations remains an issue for us as it does across the electricity industry. We have a continuing need to deal with asbestos safely for the protection of our staff and contractors. We have mapped all our substations containing asbestos and signage has been erected. We will continue to deal appropriately with any exposed asbestos or any requirement to deal with it during our network investment programme.

Comparing ED1 to DPCR5

Legal & Safety		DPCR5		RIIO-ED1		
		D5 pa £m	Total £m	ED1 pa £m	Total £m	% change
General Security	SPD	0.2	0.9	0.4	3.1	106%
	SPM	0.6	2.9	0.4	3.5	-24%
Mural Wiring	SPM	1.1	5.3	1.5	11.6	37%
Fire Protection	SPD			0.1	1.2	
	SPM			0.1	1.2	
OHL Defects	SPD	0.4	2.1	1.3	10.6	224%
	SPM	1.8	8.8	1.3	10.7	-24%
Metal Theft	SPD	0.1	0.6	0.8	6.1	573%
	SPM	0.2	0.8	0.5	4.3	247%
Asbestos Management	SPD	0.0	0.1	0.0	0.4	147%
	SPM	0.1	0.5	0.0	0.4	-48%
Air Break Switches	SPD	0.2	0.8	0.1	0.4	-67%
	SPM	0.1	0.3			
Recreational Sites	SPD	0.3	1.7	0.3	2.3	-14%
	SPM	0.1	0.3	0.3	2.4	368%
Earthing Upgrades	SPD	0.2	0.8	0.1	0.6	-53%
	SPM	0.4	1.8	0.2	1.8	-39%
Total		**5.6**	**27.8**	**7.6**	**60.8**	**27%**

Cost Benefit Analysis

The majority of Legal and Safety activities are not optional and we have not performed a CBA analysis on them. For mural wiring there are some options for replacement which we have considered and the summary outcome is as below.

Option no.	Options considered	Decision	NPVs based on payback periods			
			16 years	24 years	32 years	45 years
1	Baseline- Repairing the mural wiring on failure	Rejected	£0.00	£0.00	£0.00	£0.00
2	Like for Like Replacement	Rejected	£3.30	£5.38	£7.42	£10.49
3	Renewing the mural wiring on a "like for like" basis every 25 years, where technically feasible.	Adopted	£3.30	£5.38	£8.02	£12.71
4	Protected Mural Wiring Replacement	Rejected	£2.56	£4.43	£7.49	£12.65
5	Underground Replacement	Rejected	-£2.30	-£1.77	£0.39	£4.62

8.3.15 ESQC Regulations

Following the introduction of The Electricity Supply, Quality and Continuity Regulations (ESQCR) in 2002, a number of obligations were introduced in relation to our existing overhead lines. This expenditure category relates to our undertakings to the Health and Safety Executive (HSE) to comply with Regulations 17 and 18.

Our Plan

ESQCR		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
ESQCR LV	SPD	6.6	33.0	5.2	41.5	-21%
	SPM	11.8	59.0	5.9	47.5	-50%
ESQCR 33kV & 11kV	SPD	0.1	0.5	0.8	6.4	781%
	SPM	0.5	2.3	1.7	13.7	268%
Total		19.0	94.8	13.6	109.1	-28%

Regulation 17 refers to the minimum ground clearance of overhead lines over roads and other locations. We have identified approximately 35,000 LV overhead line locations (14,700 in SPD and 20,300 in SPM) that breach minimum clearance and require rectification.

Regulation 18 stipulates minimum clearance of overhead lines to structures and other obstacles and we have identified approximately 46,200 LV overhead line locations (24,700 in SPD and 21,500 in SPM) that require modification to remove non-compliances.

The ESQCR driven LV intervention volumes total 39,382 in SPD and 41,743 in SPM and are indicated in the table below with related expenditures of £42m and £48m respectively. An additional 10,500 ESQCR LV non-compliances, 4,500 in SPD & 6,000 in SPM, will be rectified and funded through our LV village modernisation programme.

Inspection of our HV and EHV overhead lines has identified approximately 10,000 ESQCR hazards. Resolution of these HV network hazards will be complete by 2020/21 with an expenditure of £6.6m in SPD and £13.7m in SPM.

We have provided a schedule for these remedial actions to the HSE and are committed to completion by FY 2020/21.

8.3.16 Undergrounding in National Parks and AONB

Our Plan

AONB		DPCR5		RIIO-ED1		
		D5 pa	Total	ED1 pa	Total	% change
		£m	£m	£m	£m	
AONB	SPD	0.0	0.1	0.5	3.7	N/A
	SPM	0.5	2.6	1.0	7.6	84%
Total		**0.5**	**2.7**	**1.5**	**11.3**	

The geographic area covered by our SPM and SPD licence areas includes a number of National Parks and Areas of Outstanding Natural Beauty (AONB). In SPM this encompasses stakeholders such as Snowdonia National Park, Anglesey, Llyn Peninsula, and Denbighshire AONBs and in SPD includes Loch Lomond and The Trossachs National Park.

Electricity distribution in rural areas is predominantly provided by overhead networks that can sometimes impair the visual amenity of important sites or popular tourist areas. These overhead lines have been in place for many years and, where considered to be intrusive, the selective replacement of some lines with underground cable can enhance visual amenity.

SP Energy Networks will continue to consult with our stakeholders and other appropriate interest groups to identify the areas that would most benefit from the undergrounding of overhead lines. Regular discussions will be held with established groups to maintain our positive relationships and to identify and prioritise such undergrounding projects. Our relationship with Snowdonia National Park is particularly strong through the implementation of a signed ‘accord’ that ensures our collaborative working.

8.3.17 Oil Pollution Mitigation

Fluid Filled Cables (FFCs) have been used in the UK since the 1960s; the fluid in the cables acts as an electrical insulator. FFCs have proved to be extremely reliable electrically. However, there are environmental risks associated with leakage from old cables.

We identify the need to reduce oil leaks of poorly performing 132kV cable. Therefore, we plan to replace 10.9km of the 132kV cables by 2017, with solid polymeric alternatives, which should result in a 50% reduction in leakages over the duration of the RIIO-ED1 price control period.

Oil Containment

Licence	Number of transformers bunded	Expenditure (£m)
SPM	**152**	**8.1**
SPD	**224**	**12.0**

Oil is used within transformers for insulation and cooling, with the volume of oil increasing with the operating voltage.

For all new 132kV & 33kV transformers we install an oil containment bund so any oil leaks are captured within it.

During ED1 we plan to install oil containment bunds on 152 33kV transformers in SPM and 224 in SPD. This will be a risk based plan and will be delivered depending on the proximity of the transformer to water courses etc.

Unbunded transformer

New bunded transformer

8.3.18 Reducing Technical Losses

Our Plan

We will implement a number of technical loss mitigation initiatives during the ED1 regulatory period. We are also committed to evaluating a range of innovative new measures for potential implementation later in period, as outlined below. Our philosophy for technical loss reduction is to adopt a holistic approach which considers a range of factors to maximise overall benefits to customers. The principles underpinning the planned losses reduction initiatives to be implemented during ED1 are to maintain network security, reliability, quality of supply and also to avoid compromising the asset health of existing infrastructure. All loss reduction initiatives will also be subject to rigorous cost-benefit analysis to ensure each is economically justified. Furthermore, many of the loss reduction initiatives planned will provide wider benefits to customers in terms of increased network capacity, greater flexibility to integrate LCT technologies and better resilience to adverse weather conditions.

Transformers

Licence	Number of transformers replaced	Expenditure (£m)
SPM	**627**	**6.5**
SPD	**484**	**4.5**

We procure all transformers based on the lifetime cost of the transformer, incorporating capitalisation of losses, over a transformer working life expectancy of 40 years.

Manufacturers offer transformer designs to provide optimised cost/losses benefits. We have been using this optimised transformer procurement policy since 2005 and our experience demonstrates that manufacturers consistently provide transformers that are lower loss than required by our minimum transformer design specification. We will review this policy to reinforce the challenge to manufacturers as the proposed Ecodesign transformer standards are adopted.

EU Directive 2009/125/EC will mandate the adoption of Ecodesign power transformers in two stages; Tier 1 on 1st July 2015 and Tier 2 in 2020. The proposed Ecodesign requirements specify new maximum load and no-load losses for all power transformers deployed within our networks and peak efficiency requirements for large power transformers.

In addition to our transformer asset replacement programme, we have identified a population of particularly high loss secondary transformers installed in both licence areas prior to 1962. Transformers manufactured prior to 1962 were produced using a core manufacturing process that resulted in efficiencies that are approximately 60% poorer than modern transformer designs. Replacement of several of these high loss transformers is incorporated into the core asset replacement programme but we will replace additional pre-1962 units in a drive to proactively reduce network losses. Replacement of these additional transformers will be prioritised by highly loaded and utilised units to realise the greatest benefits early in the RIIO-ED1 period.

We have a population of 3,201 pre 1962 secondary transformers and we plan to replace a total of 1,347 during the RIIO-ED1 period; 1111 from the losses driven initiative and 236 in the asset replacement programme.

Overhead line conductor

We have been operating an overhead line resilience policy based on a geographical demarcation of normal and severe weather areas. Asset replacement and new build, reinforcement driven overhead line investments in normal weather areas are currently constructed with lighter 50mm² conductor whereas those in severe weather areas utilise heavier 100mm² conductor.

Additional loss reduction options have been considered for normal weather areas during the RIIO-ED1 period and cost benefit analysis performed. A full CBA is provided in that justifies the installation of larger size conductor when rebuilding OHL in normal weather areas. The CBA demonstrates that it is beneficial to construct all main line rebuilds with the heavier 100mm² conductor and this policy has been adopted for RIIO-ED1.

Underground cables

In 2009 we commissioned a study by EA Technology Ltd (EATL) into the effects on losses from installing larger section LV and 11kV cables on a selection of typical circuits with varied demand profiles, e.g. domestic, commercial and mixed. The EATL report[2] analysed new installations only and included cost benefit analysis examining the benefits attributable to the DNO, customer and environment based on, respectively; a £48 / MWh incentive rate, cost reduction reflected in bills and reduced CO_2 production. Whilst the overall benefit from totalling these three factors was generally positive the benefit to the DNO alone could not be justified and we, therefore, did not change policy at that time to install larger section cables.

We are committed to loss mitigation and will update the 2009 EATL study to better reflect our holistic approach, considering the wider customer and societal benefits to be delivered over theED1 period. The revised study will be extended to consider additional factors such as future load growth, stock holding costs and procurement volume discounts on the cost benefit analysis.

6.6kV to 11kV voltage uprating / rationalisation

We will continue our ongoing programmes, in both SPD and SPM, of uprating islands of distribution network currently operating at 6.6kV to 11kV. This work programme is demand and capacity driven but will also contribute to our loss mitigation endeavours. A total of six 6.6kV islands, 2 in SPD and 4 in SPM, will be uprated during ED1 with the final two in SPD uprated in ED2. A further 3 island groups in SPM will be uprated during the ED2 period and the final 2 island groups completed in ED3.

Substation energy consumption

Our grid and primary substations have equipment rooms and switch rooms that house the main assets and accompanying control systems. These rooms are temperature controlled to prevent condensation within the

2 Reduction of Losses and Carbon Dioxide Burden in Cables, G. J. Le Poidevin, February 2009.

equipment and subsequent degradation in its condition. Increasing provision of power supplies for electronic and IT equipment within the substation is also increasing demand and energy consumption.

During ED1 we will embark on a programme of work to improve the resilience of control and protection systems at grid and primary substations. This initiative, described in ANNEX C5 - Black Start Capability – SPEN of the business plan, is likely to further increase substation demand due to increased battery charging and control system requirements.

We remain committed to quantifying and managing the energy consumed by our substations which is required to ensure safe and resilient network operation. From a settlement perspective, the electricity consumed by our substations is treated as an unmetered supply where the total consumption for each network area is determined by the number and load characteristics of different types of substation. Throughout ED1, it will become increasingly important to update the unmetered supplies inventories for our substations on a regular basis to reflect the changes to the equipment installed on each site.

Potential Innovation / Stakeholder highlights

- *Reducing substation energy consumption*
- *Voltage regulation & optimisation*
- *Optimisation of network configuration*
- *Secondary substation and LV network monitoring*
- *SPM secondary transformer 'standby' opportunities*

Cost Benefit Analysis

We have considered a number of options for transformer replacement and the summary outcome is shown below. Further detail is provided in ANNEX C6 – Cost Benefit Analysis, reference 1.1 and 1.2.

SPD GM transformers (ref 1.1)

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Baseline- Replace HV distribution transformers driven by ED1 RMU programme only	Rejected	Not most economic	£0.00	£0.00	£0.00	£0.00
2	on top of baseline target high loss units (pre 1962) out with RMU programme based on load	Adopted	Most economic deliverable option	-£0.24	£0.60	£1.26	£1.92
3	on top of baseline, replace remainder of all high loss (pre 1962) HV distribution transformers in ED1	Rejected	Rejected on the basis of delivery constraint	-£1.29	£1.23	£3.22	£5.20

SPM GM transformers (1.2)

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	Baseline- replace HV distribution transformers driven by ED1 RMU programme	Rejected	Not most economic	£0.00	£0.00	£0.00	£0.00
2	On top of baseline target high loss (pre 1962) and poor condition units out with RMU programme based on load	Adopted	Most economic deliverable option	-£0.44	-£0.01	£0.33	£0.67
3	Replace all high loss (pre 1962) HV distribution transformers in ED1	Rejected	rejected on the basis of delivery constraint	-£1.40	-£0.32	£0.55	£1.41

We have considered a number of options for OHL replacement and the summary outcome is shown below. Further detail is provided in ANNEX C6 – Cost Benefit Analysis, reference 68.1 and 68.2.

SPD OHL (ref 68.1)

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	100% of normal weather rebuild to 50mm² AAAC conductor	Rejected	Separate programmes not cost effective	£0.00	£0.00	£0.00	£0.00
2	100% of normal weather rebuild to 100mm² AAAC conductor	Adopted	Most economical solution	£0.14	£0.35	£0.54	£0.82
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected	Not most economical solution	£0.07	£0.18	£0.27	£0.41

SPM OHL (ref 68.2)

Option no.	Options considered	Decision	Comment	NPVs based on payback periods			
				16 years	24 years	32 years	45 years
1	100% of normal weather rebuild to 50mm² AAAC conductor	Rejected	Separate programmes not cost effective	£0.00	£0.00	£0.00	£0.00
2	100% of normal weather rebuild to 100mm² AAAC conductor	Adopted	Most economical solution	£0.15	£0.36	£0.54	£0.81
3	50% of normal weather rebuild to 100mm² AAAC conductor	Rejected	Not most economical solution	£0.08	£0.18	£0.27	£0.40

8.3.19 Noise Mitigation Measures

Our Plan

Noise mitigation measures		
Licence	RIIO ED 1 Units Added	RIIO ED 1 Expenditure (£m)
SPM	24	1.8
SPD	24	1.8

All transformers transmit noise and on occasion, due to their proximity to customers' properties, they can cause a disturbance. Any reported noise nuisances are investigated using accurate monitoring equipment and any that breach the industry agreed threshold will have mitigation measures fitted. These can take the form of noise shields which deflect noise way from the customers' property or, complete noise enclosures which surround the transformer. If these mitigation measures are not sufficient to reduce the noise level to acceptable levels, then the decision can be taken to replace the transformer for a new quieter unit.

Comparing ED1 to DPCR5

Noise mitigation measures (£m)			
Licence	DPCR5	ED1	% change from DPCR5
SPM	0	0.2	N/A
SPD	0.1	0.2	100%

8.3.20 Worst Served Customers

For the RIIO-ED1 period, Ofgem has redefined worst served customers (WSC) as those that experience 12 or more interruptions due to faults on the high voltage network over a three year period, with a minimum of three in each year. In our licence areas there are approximately 4,400 customers meeting this definition.

As the customer group contained within the worst served category varies from year to year it is anticipated that the average annual number will continue at a similar level without intervention. We will invest in additional protection and remote control facilities and, where cost-effective solutions are available, network reconfiguration or refurbishment in the vicinity of the affected customers.

We are targeting a 25% reduction in the average number of high voltage interruptions affecting worst served customers.

Worst Served Customers expenditure (£m)			
	SPD	SPM	SPEN Total
DPCR5 Annual Average	0.0	0.0	0.0
RIIO-ED1 Annual Average	0.57	0.25	0.83
RIIO-ED1 Total (8 years)	**4.6**	**2.0**	**6.6**

9 Network Operating Costs

We are responsible for looking after all of the assets that are installed on our network and alongside renewing assets that are life expired or no longer capable of meeting load requirements, we need to inspect, maintain and repair the asset base to ensure it continues to provide a safe, secure and reliable electricity supply to our customers. Funding requirements for these activities, along with some other minor operating costs are set out in this section.

9.1 Incident Response

9.1.1 Trouble Call

Through our investment, inspection and maintenance programmes, we seek to provide our customers with a highly reliable power supply. However, given the nature, scale and complexity of the asset base making up our network, faults are an inevitability. Over the last 8 years, we have invested in additional network automation and control to make reductions in both the average number of customers affected by a fault and the time to restoration.

When faults happen, our priority is to restore customers' supplies as quickly as possible. Where we cannot undertake a permanent repair quickly, we also consider the options of temporary repair and deployment of mobile generation.

Within the industry, the term 'Trouble call' is used to describe situations where our staff respond to incidents on our network including:

- *Restoring customer supplies after a fault*
- *Making repairs to our network after a fault*
- *Responding to other types of incidents which do not affect supplies, for example public safety incidents*

We subdivide our Trouble call incidents into 2 types, in line with regulatory reporting guidance:

- *Quality of Supply (QOS) Incidents: Unplanned incidents that result in a loss of supply to customers or the inability of a component of the network operating at power system voltage to carry load or fault current for more than 3 minutes, excluding incidents that result from failures at or after cut-outs. These incidents are covered by the Interruption Incentive Scheme (IIS).*

- *Non-Quality of Supply (Non-QOS) Incidents: All other incidents that require a response from us, also known as Occurrences Not Incentivised (ONIs).*

To establish our Trouble call expenditure plan, we

- *Reviewed our Trouble call volumes for the last 5 years (QoS) and 3 years (Non QoS) to establish a baseline activity level using multi-year averages*

- *Analysed the causation of the faults to understand the proportion that will be influenced by our proposed investment plans. We developed a model to take account of this interaction, along with the impact of asset deterioration over the ED1 period to produce a forward projection of fault volumes, split out by asset type*

- *Assessed the extent to which we expect the projected fault volumes to be addressed through repair or asset replacement using historic trends to inform our apportionment*

- *Applied the appropriate unit cost for each asset type and reinstatement activity (each unit cost was reviewed to ensure it was efficient prior to use in this calculation) to produce our cost projections.*

9.1.2 Responding to 1 in 20 Year Storms

Within our cost projections, we also take account of the cost of responding to infrequent severe storms, known as 1 in 20 year storms. As set out in Chapter B of our Plan, section 2, Our Challenges, large proportions of our service areas are classified as severe weather areas and every year, we typically have to deal with a number of storms, some of which are classed as 'exceptional events', a regulatory classification for incidents that cause at least 8 times the daily average of faults at higher voltages. Our historical averages are that we experience 1.3 exceptional events in SPM and 2 in SPD per year. The costs of dealing with these storms are included in our Trouble Call projections. Our long-standing focus on improving network resilience to severe weather, allied with our highly developed storm response processes ensure that we are consistently amongst the best performing DNOs in mitigating the impact of these events on our customers.

However, on a less frequent basis, we can experience severe storms which cause extensive network damage. These '1 in 20 year' events are currently defined by the number of higher voltage faults experienced within the first 24 hours of the event – for SPM, the threshold is 355 faults and for SPD it is 399. The February 2014 storm that caused massive disruption in North Wales is likely to be classified as such an event. To cover the cost impact of these severe weather events, we have estimated the annualised average extra cost of dealing with them at £0.5M per annum per licence.

9.1.3 Incident Response Costs

As shown in the following table, incident response costs across both of our licence areas are forecast to remain relatively stable over the RIIO-ED1 period. Within this forecast, we have assumed a slight increase in the frequency of severe weather events over DPCR5. Our costs provide for the repair of more than 180,000 faults and attendance at around 470,000 other incidents.

Incident Response	DPCR5			RIIO-ED1									
	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	RIIO-ED1 Total
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
SPD	27.7	26.7	23.2	23.4	22.6	23.3	23.1	22.8	22.5	22.2	22.0	21.9	21.7	179.6
SPM	21.9	17.2	19.5	20.1	19.9	20.7	20.3	20.1	19.7	19.4	19.3	19.1	18.8	157.3
SPEN	49.6	43.9	42.7	43.4	42.5	44.0	43.3	42.9	42.2	41.6	41.3	41.0	40.5	336.8

There are occasions where the work that we need to undertake in response to a call we receive is chargeable to a third party, for example, where a third party is responsible for damage caused to our equipment. Where possible, we seek to recover these costs and the table above shows our net expenditure after recoveries . Within the ED1 period, we have assumed that we will be able to recover over £15M from third parties in relation to incident response. The following table shows the breakdown of our Troublecall costs by category and shows the effect of recoveries on our gross expenditure level.

Total Incident Response expenditure in RIIO-ED1 (£m)			
	SPD	**SPM**	**SPEN Total**
Incentivised Events	148.2	122.4	270.6
ONI's	35.4	38.1	73.5
Total Gross Expenditure	**183.6**	**160.5**	**344.1**
Cost Recoveries	-8.0	-7.2	-15.2
Total Net Expenditure	**175.6**	**153.3**	**328.9**

9.1.4 Fault Management

During DPCR5, we have made a number of significant improvements in how we manage faults. We have:

- *Implemented a new fault management system (PowerOn), which has resulted in improved incident management and reporting, and has allowed us to enhance the service to our customers.*
- *Introduced other new systems (ENPaRT & RedOwl) which have given us a more robust planning and resource scheduling tool resulting in improved resource utilisation and productivity outputs.*

- *Established a dedicated operational commercial team which has increased our detailed understanding of the costs associated with fault activity and undertaken awareness and training programmes with our managers and field engineers to enhance their understanding of fault cost analysis and reporting.*

- *Trained field staff in new fault locating technology and techniques, particularly for use on our LV network*

- *Renegotiated our cable excavation and backfill contracts, resulting in substantially better commercial terms and service levels*

- *Introduced a number of initiatives to assist in the restoration of customer supplies such as smart EFI technology and LV smart fuse technology.*

- *Developed our mobile IT platform to support incident creation, reporting and closure.*

- *Engaged specialist consultants to help us review our processes and initiatives against recognised industry benchmarks*

These improvements have delivered a reduction in our fault costs of over 30%.

We continue to look for new ways to reduce the impact of faults on our customers. As we move from DPCR5 into RIIO-ED1, we will:

- *Implement Logic Sequence Switching (LSS) across 500 circuits in SPEN. LSS uses software templates to automate the switching of our 5,000 network controllable points in the event of a fault.*

- *Develop the use of impedance mapping techniques on our high voltage networks. This process uses remote active network analysis to progressively narrow down the source of a fault allowing us to dispatch our teams to a tightly defined target area.*

- *Implement a revised mobile generator strategy. In support of Ofgem's proposal to move the EGS2 target from 18 hours to 12 hours, we have reviewed our use of mobile generation and will in future operate generator deployment from within our Business as well as via third party providers.*

- *Continue to develop our staff - our field technicians are now capable of performing all tasks requiring specific safety authorisations on our LV and 11kV systems, as well as limited 33kV activities. We will continue to increase staff flexibility and capability to deal with any situation presented in the field, further extending authorisations and providing the latest technology to allow swift fault identification and location leading to improved restoration times.*

- *Enhance our mobile IT platform further, deploying auto dispatch and field status management through hand held devices to all faults field staff. This works in tandem with our 'toughbook' technology, providing mobile access to our mapping, work management and network management systems.*

- *Review and implement improvements to both our field vehicles and logistics processes to ensure maximum effectiveness and responsiveness.*

All of our staff related initiatives, targets and expectations are brought together in our performance management system which targets individual team members with specific objectives contributing to network performance improvements. This system is designed to reward staff who deliver on and exceed these targets.

These initiatives and investments are governed through a Network Improvement projects programme to ensure that implementation is co-ordinated and complimentary. This programme is overseen by a project board including staff from across our Business. Moving into ED1, this governance will continue to ensure that every opportunity is taken to continue to improve our network performance.

Through investing in these initiatives and a relentless operational focus on restoring customers as quickly as possible, we aim to reduce the average number of times our customers lose their supply by 7% and reduce the length of time those customers are without power by 16%.

9.2 Inspection and Maintenance

The purpose of our inspection programmes is to identify safety, security or asset condition issues that need to be addressed in order to maintain the integrity of our network. Our maintenance programmes aim to ensure that our equipment remains in a safe and operable condition for the duration of its useful life. Effective inspection and maintenance programmes are essential elements of our approach to meeting our legal obligation under the Electricity Safety, Quality and Continuity Regulations (ESQCR 2002) to maintain the safety and reliability of our network.

A large proportion of our network assets were installed in the period 1950-1970. This means that we are renewing increasing volumes and managing higher proportions of assets that are near the end of their useful lives. As any asset ages then typically the costs of ensuring they continue to perform adequately increase, networks are no different. We seek to limit this pressure to increase expenditure through advancing our understanding of asset condition and deploying new, more cost effective techniques.

Network maintenance has traditionally been dominated by time based interventions, where standard activities are undertaken on assets on a fixed frequency, regardless of condition and performance. Although this approach remains appropriate in many instances, we are increasingly looking to enhance the effectiveness and cost efficiency of our maintenance programmes by moving to a condition based approach where this can add value. For example, in DPCR5, we have:

- *Introduced an efficient low cost oil testing programme to identify oil degradation in ring main units. Rather than undertaking maintenance purely on a fixed frequency regardless of condition, we now use the results of this monitoring programme to target our maintenance on those assets that are showing signs of deterioration.*

- *Addressed a concerning trend of increased customer interruptions in late DPCR4 caused by the slow operation of some circuit breakers. Our analysis indicated that our time-based maintenance programme was not adequately addressing this issue. Through the introduction of trip testing to monitor the speed of operation and improvements in our circuit breaker maintenance procedures, we resolved the issue successfully. We now undertake trip testing as a core element of our maintenance programme and this has delivered a significant improvement in circuit breaker reliability whilst also saving costs through the elimination of unnecessary maintenance activity.*

Our inspection and maintenance (I&M) requirements are set out in our comprehensive suite of asset management policies, which form part of our fully accredited PAS55 management system. We keep these policies under regular review to ensure that we capture feedback from implementation, incorporate new techniques and address any emerging issues. This process is informed by the results of a structured asset risk assessment methodology which forms part of our Business management reporting system.

In preparing our ED1 plan, we:

- *carried out a detailed review of our I&M regimes and in addition to confirming the requirements to continue with a large proportion of our work programmes, the review identified a number of revisions to our policies which we have incorporated into our plan, for example, the introduction of a new inspection activity for service positions following on from the roll-out of smart meters.*

- *reviewed the unit costs for all activities, making adjustments as necessary to ensure that they were fully efficient*

Our strategy is to improve our understanding of our ageing assets through detailed inspection and condition assessment. In ED1, we will continue to progress in this direction, enabled by a significant increase in information gathered through the deployment of condition monitoring equipment on our networks, including:

- *Monitoring of transformer deterioration, enabling life extension or asset replacement works at the most appropriate time.*
- *Measurement of circuit breaker performance, with embedded intelligence highlighting developing problems which can be addressed before they cause failures.*
- *Low cost load monitoring technology at secondary substations, trialled in one of our Low Carbon Network Fund projects, will provide a much more detailed view of network conditions.*

There are associated costs along with the benefits of deploying these new technologies.

- *Online monitoring requires telecoms bandwidth to support an increase in communications traffic.*
- *New systems and processes are required to enable analysis and decision making*

9.2.1 Inspections

Although we have introduced efficiencies and refined our policies, our overall inspection costs will increase due to:

- *A new programme of customer service position inspections, commencing in 2021, prioritised using information gathered during smart metering roll-out by Suppliers*
- *Additional inspections associated with new requirements for fire risk assessment*
- *Increased frequency of overhead line inspections (from a 10 year cycle to a 6 year cycle) to better manage risks including change of land use and improve the currency of condition information*
- *Inspection of 132kV and 33kV cable tunnels, bridges and strategic routes to assess security and risk*

9.2.2 Maintenance

Maintenance costs within our plan increase due to:

- *Increased 33kV and 132kV tower painting requirements*
- *More intrusive and extensive maintenance on older assets*
- *Increased levels of condition assessment to improve future investment plans*

These cost increases have to some extent been offset by:

- *a reduction in BT line rental costs*
- *management of defects & hazards through our refurbishment plans*
- *installation of new low maintenance assets (e.g. SF6 switchgear)*

Our inspection and maintenance costs are summarised in the following table:

Activity p.a.	DPCR 5	RIIO ED 1	% CHANGE
Inspections	£3.8m	£4.1m	8%
Maintenance	£9.1m	£10.8m	19%
Totals p.a.	**£12.9m**	**£14.9m**	16%

9.3 Vegetation Management

Managing vegetation growth in and around our assets is an important aspect of maintaining the safe and reliable operation of our system. The key activities we undertake are:

- *Tree cutting to ensure safety distance clearances are maintained around our overhead lines - this work is done in compliance with an industry standard known as ENATS 43-8*
- *Tree cutting and management within falling distance of our overhead lines to enhance storm resilience - this work is also covered by an industry standard known as ETR132*

Vegetation Management		DPCR5	RIIO-ED1		
		£m pa	£m pa	Total	% change
Vegetation Management	SPD	4.1	7.8	62.3	48%
	SPM	11.9	11.3	90.5	-6%
Total		16.0	19.1	152.9	19%

Tree Cutting forms a fundamental component of our overall strategy for the management of our overhead lines, and is critical to maintaining safety and performance, particularly in storm conditions. Overall, our total tree cutting costs will rise from £4m to £8m per annum in SPD due to increased cutting of trees to improve resilience in storm conditions. In SPM, costs will reduce from £12m to £11m per annum in SPM due to reductions associated with the achievement of an efficient programme of safety clearance cuts offset by increased cutting of trees to improve resilience in storm conditions.

9.3.1 Tree cutting for safety clearance (ENATS 43-8)

Trees in close proximity to overhead lines can present numerous problems. From a safety perspective, trees that can be climbed introduce the risk of contact with the live conductors. Reliability can be affected by impingement from tree growth and in storm conditions, falling trees and wind borne vegetation can result in damage. The purpose of our safety clearance programme is to manage the public safety risk and maintain the reliability of our overhead line network.

We have developed detailed databases of trees growing in proximity to our overhead lines and use this data to estimate the volume of work that is required. Through experience, we have found that the optimum frequency for undertaking cuts at each location is 3 years. By ensuring that we cut the tree back to allow for 3 years of regrowth before the safety distances are infringed, we can repeat the process in the most cost effective way without the need to undertake the work using more expensive 'live working' techniques or to arrange planned outages on the lines for the work to take place. In SPD, we have achieved this mode of operation across the majority of our network and in SPM, we are working towards having this regime in place fully by the end of 2015.

In developing our costs for safety clearance tree cutting, we have taken account of the savings we expect to make in SPM as a result of getting the full system into a 3 year cycle.

9.3.2 Falling Distance Tree Cutting (ETR132)

From our experience of dealing with high impact storms in the late 1990s and our pioneering ‘Rural Care’ programme through which we achieved falling distance clearance for over 5600 km of our high criticality 33kV and 11kV circuits, we were instrumental in the development of an industry standard for storm resilient tree management. This standard, referred to in the industry as ETR 132, is a risk based approach to managing trees within falling distance of overhead lines.

In 2009, we set a target, in line with a UK Government recommendation to the industry, to increase the percentage of our network that is compliant to the ETR132 standard by 20% over a 25 year period. Our experience has shown that where possible, the most efficient mechanism to deliver this severe weather resilience is by undertaking the tree clearance work in combination with our line rebuilding and refurbishment programmes. This has been our approach in DPCR5 and will continue through ED1. This also gives us the ability to achieve compliance in some instances by relocating sections of the line to avoid the need to cut down trees. Through ED1, we will continue to progress towards the achievement of this long-term target. In addition to achieving compliance alongside our rebuild and refurbishment programmes, we are also planning to undertake some stand-alone targeted ETR132 works, particularly on spur lines with high customer numbers.

For ED1, we have also added in a new activity of ETR132 maintenance in order to ensure that we manage regrowth to retain compliance on circuits that have been previously made compliant to the standard.

In summary, the cost of our storm resilience tree cutting programme will increase In ED1 compared to DPCR5 due to:

- *Addressing vegetation “grow back” on sections of the network already made resilient.*
- *Extension of our programme to include selected spur lines with high customer numbers.*

9.3.3 Other Network Operating Costs

Other Network Operating Costs														
	DPRC5				RIIO-ED1									ED1 Total
	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	
	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
SPD	3.9	4.1	3.9	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	17.4
SPM	0.5	0.7	0.7	2.3	2.3	2.3	2.3	2.3	2.4	2.3	2.3	2.3	2.4	18.8
SPEN	4.4	4.8	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	36.2

We also have other Network operating costs associated with dismantlement of assets which are no longer required and purchase of electricity that we use in our substations for heating and operation of equipment such as battery systems.

Our current electricity purchases are based upon estimates of consumption (as this is more cost effective than metering all substations). Historically in SPM, we have estimated lower energy consumption than SPD as many substations have lower energy dehumidifier units instead of heaters, although this is offset by higher the greater population of substation buildings in SPM.

We have installed metering at a number of substations in both our network areas to provide more up to date estimates for our modern substation equipment, and are also following a programme of reducing energy consumption where this is cost effective.

9.4 SPM Company Specific Factors

We incur additional network operating costs in operating the Manweb urban interconnected network compared to a traditional radial network design. We have assessed the cost difference to be £12.67M over the ED1 period, as set out in the following table.

SPM Company Specific Factors					
Category	CV table	Row No.	Normal Track SPM RF submission		SPM Regional Cost Factors - Rationale
33kV I&M					
Substation maintenance, inc pfm	CV13	44, 45 & 46	£	2.23	Based on discharging SPM substation maintenance policy and unit costs for 33kV assets including those associated with SPM discrete 33kV unit protection systems, inc post fault. Cost differential based on removing the SPM discrete Unit protected network elements from plan as not required on Traditional Industry Networks
Underground pilot cable faults	CV15b	17	£	3.36	
3rd Party rented communication & protection pilots	CV13	71	£	2.17	Based on ED1 plan to continue to rent BT communications services pre and post BT21CN transition. Costs assume rental cost will remain constant. Cost differential based on Removing 33KV unit protection costs from budget.132kV and Grid site costs excluded from SPM RF case.
Translay unit protection battery replacement pro	CV13	49	£	0.02	Based on ED1 plan to replace batteries associated with Translay unit protection intertrip batteries on 8 year roiling programme, SPM discrete asset on unit protection schemes. Cost differential based removing requirement from programme as not required on Traditional Industry Networks
Underground cable fault repair	CV15a	30	£	0.97	Based on additional costs are associated with the length of cable being repaired in an interconnected system being 20-75% longer than the equivalent radial system. It is necessary to replace a longer length because the higher fault level leads to more cable being damaged around the site of a fault. Cost differential based on SPM volumes at SPD unit cost as a proxy for traditional network design
sub tot			**£**	**8.74**	
HV I&M (11 & 6.6kV)					
X- type Secondary substation maintenance, inc	CV13	28, 29 & 30	£	2.10	Based on discharging SPM substation maintenance policy and unit costs for HV assets including those associated with SPM discrete HV unit protection systems, inc post fault. Cost differential based on removing SPM discrete X-Type discrete costs and volumes and applying SPM non X-Type unit cost to remaining assets.
sub tot			**£**	**2.10**	
LV Networks					
Underground cable fault repair	CV15a	17	**£**	**1.83**	Based on additional requirement for extra fault finding excavation of LV open circuit faults which are difficult to locate on interconnected circuits. Cost differential based on SPM volumes at SPD unit cost as a proxy for traditional network design
		£m	**£**	**12.67**	

10 Closely Associated Indirect Costs

10.1 Overview

To deliver our outputs and secondary deliverables effectively, our front line staff and contractors rely on an extensive and efficient network of support staff and services. The costs we incur in providing these services are referred to as Closely Associated Indirects and Business Support Costs.

These are covered in the following sections 10.2 and 10.3.

10.2 Closely Associated Indirect Costs

10.2.1 Introduction

Closely Associated Indirect (CAI) costs are those expenditures which are essential to ensuring the Business' direct (investment and maintenance, labour, contractor and materials) activities are targeted in the right areas in a cost effective way, such that operational and key business risks are understood and that the direct activities of the Business can progress effectively on a daily basis.

Ofgem Regulatory Reporting Rules and Guidance define this category as consisting of eleven separate activities, which can be arranged into two categories:

A. *CAIs that vary dependent on investment and operational workload and volumes including: network design and engineering; project management; vehicles and transport; operational training; small tools, equipment, plant and machinery*

B. *CAIs that are essentially a fixed cost of running a network business and do not typically vary with workload: engineering management and clerical support (including Wayleaves); control centre; contact centre; stores; network policy; system mapping - cartographical*

Across all of our expenditure activities we have conducted an extensive benchmarking and cost assessment exercise, details of this work is outlined in section 6 of this annex and annex C6 – Cost Assessment, Efficiency and Benchmarking - SPEN.

In our July plan, using regulatory reporting data for 2012/13 and the March 2013 RIIOED1 publications from other DNOs, we had conducted an ordinary least squares regression analysis, using Modern Equivalent Asset Value (MEAV) as a cost driver to establish what an efficient level of CAI costs that a company of our scale would incur. This exercise identified that our CAI costs would need to reduce in comparison to the upper quartile companies by approximately £23m pa and we factored this in to our previous submission.

Despite this significant reduction, in November 2013 Ofgem stated *"For closely associated indirects, SPEN's expenditure appears less justifiable than other DNOs and both its DNOs benchmark poorly, with SPD benchmarked as the least efficient company for the regressed CAI activities"*

The Ofgem Fast Track benchmarking process however deployed a <u>weighted</u> MEAV as the main cost driver and subsequent econometric work undertaken by NERA and our team has shown that the model deployed had poor explanatory powers and was volatile to changes in key assumptions and in the model parameters. With NERA's help we have therefore proposed a number of alternative models on a regression basis that we think are more robust overall, again details of these models can be found in our benchmarking annex C6 – Cost Assessment, Efficiency and Benchmarking - SPEN.

None the less we have reviewed our costs from top to bottom and we have now propose a reduction in CAIs of £28m pa when compared to our DPCR5 averages.

In 2013, to ensure we could deliver savings of this level we established a Business Readiness Programme Team to prepare for RIIOED1 and to develop an implementation plan for organisational changes and other business efficiencies that will position us amongst the most cost efficient operators in the industry.

The following table summarises our closely associated costs forecast for RIIO-ED1

	Closely Associated Indirect expenditure RIIO-ED1 (£m)				
	DR5 Total (£m)	DR5 Average (£m)	ED1 Total (£m)	ED1 Average (£m)	% Change
Network design and engineering	50	10	40.5	5.1	-49%
Project management	75.5	15.1	62.4	7.8	-48%
Engineering management and clerical support	206	41.2	229.3	28.7	-30%
System Mapping	13.5	2.7	15.7	2	-26%
Control Centre	42.5	8.5	48.3	6	-29%
Call Centre	17.5	3.5	21.8	2.7	-23%
Stores	19	3.8	15.7	2	-47%
Network Policy	11	2.2	10.8	1.3	-41%
Operational Training	37.5	7.5	75.4	9.4	25%
Vehicles	44	8.8	57.6	7.2	-18%
Total	516.5	103.3	577.5	72.2	-30%

The following sections provide more detail about each of the relevant CAI costs:

10.2.2 Network Design and Engineering

Network design and engineering expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	4.9	5.0	10.0
RIIO-ED1 Annual Average	3.0	2.0	5.1
Difference	-1.9	-3.0	-4.9
RIIO-ED1 Total (8 years)	**24.2**	**16.4**	**40.5**

The Network Design and Engineering area covers high level planning for the development of our network as well as detailed project planning, scheme development and project authorisation.

Detailed engineering planning and design for specific individual projects is the primary cost driver within this activity. Such projects relate to specific engineering activities such as asset replacement, load reinforcement, quality of supply improvements and new connections

Within SPEN these activities are predominantly carried out through a centralised design function that has responsibility for all connection related work down to and including our 33kV network and for all replacement works and quality of supply improvements across the whole network. This area also has responsibility for our network analysis, system integrity and demand modelling.

Our centralised Design function also carries out our Transmission design activities and was a key function in ensuring that we were Fast Tracked in RIIOT1. Where relevant we share technical developments across Transmission and Distribution to improve innovation. Given the scale of the Southern Scottish Transmission system that we own and the absence of any Transmission assets on this scale in any other DNO this yields a strategic advantage for our design function that we have been able to leverage in accommodating such a high level of Renewables over the last decade.

The New Connections Business assumes responsibility for design at 11 kV and below and including minor works. Typically the customers and stakeholders at this level require more direct support from the design team and this allows for more effective engagement and customer service.

Network design and engineering activity costs are forecast to reduce reduced by £4.9m pa across our two licence areas as part of our drive for efficiency.

This reduction is also set against volume increases arising from a growing investment plan, technological changes and increases in Distributed Generation (DG), all requiring increases in engineering expertise. As we have highlighted our networks already have the highest level of Distributed Generation connected of any DNO in the UK.

10.2.3 Project Management

Project management expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	6.7	8.4	15.1
RIIO-ED1 Annual Average	2.3	5.5	7.8
Difference	-4.4	-2.9	-7.3
RIIO-ED1 Total (8 years)	**18.2**	**44.1**	**62.4**

Our work programmes from 132kV major projects to simple defect clearance programmes rely upon dedicated project managers and coordinators to manage delivery of our plans. Project management activities cover the life cycle of projects after authorisation including work preparation, construction and system connection through to accurate data capture and the application of technical and financial controls.

The work preparation phase includes detailing work instructions, identification and programming of resources, material and equipment management and liaison with procurement securing contractors and non standard materials.

The construction/connection phase is principally focussed on on-site supervision of staff and contractors, quality checks against business quality standards, organisation of network access and subsequent outages. These activities will finally result in connection of the physical assets involved in the project to the network.

Project Management costs are forecast to reduce by £7.3m pa across our two licence areas as part of our efficiency drive in ED1.

10.2.4 Engineering Management and Clerical Support

Engineering management and clerical support expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	20.6	20.6	41.2
RIIO-ED1 Annual Average	13.1	15.5	28.7
Difference	-7.4	-5.1	-12.5
RIIO-ED1 Total (8 years)	**105.1**	**124.2**	**229.3**

Engineering management and clerical support (EM&CS) relates to a variety of office based activities that support employees delivering direct activities but is not involved with either the planning of projects or project management.

The (EM&CS) category captures costs associated with executive managers, engineering managers, work programmers, resource planners, clerical staff, streetworks administration, wayleave payments and administration.

Work undertaken in this category is highlighted below:

- *Strategic Network Business Plan Development and Implementation: Development of strategic business plan for the overall distribution business; Setting the operational and capital network investment priorities for the overall distribution business; establishing annual operational and capital plans to achieve strategic goals for the overall distribution business, monitoring the achievement of plans.*

- *Work Planning, Budgeting, Allocation and Control (including line management of staff undertaking direct activity work and operational performance management):*

- *Health and Safety: Promoting and maintaining health and safety of employees, contractors, customers and the public, including: establishing procedures to comply with best practice for health and safety; Health and Safety checks on work and personnel; investigation, report and corrective action following an accident or environmental incident; operational safety checks; Providing safety advice to persons working in proximity to network assets.*

- *Streetworks admin: Processing of NRSWA notifications; Processing the payment of notification penalties (but not the cost of the penalties).*

- *Wayleave Payments/Easements/Servitudes:Admin Costs: Annual payments made to the owner and/or occupier to cover the financial impact of having equipment on their land and substation rent payments; Administration of existing wayleaves, obtaining, managing and administering Wayleave, substation rents, easements and servitudes*

- *Clerical Support: Updating plant and overhead line support asset inventory databases, programming minor works, customer liaison, processing third part claims, updating asset inventory, preparing plans and quotations and other general office duties to support direct activities.*

Overall our Engineering Management and Clerical Support costs are forecast to reduce by £12.5m pa across our two licence areas.

10.2.5 System Mapping – Cartographical

System mapping expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	1.2	1.5	2.7
RIIO-ED1 Annual Average	0.8	1.2	2.0
Difference	-0.4	-0.3	-0.7
RIIO-ED1 Total (8 years)	**6.4**	**9.3**	**15.7**

System mapping – cartographical are the costs associated with updating our network geographical records. The task is volume driven and relates directly with the levels of network investment in overhead, underground, ground mounted apparatus and load related new connections or network alterations.

We will continue to pay ongoing fixed costs in relation to licence payments to the Ordnance Survey, other costs will be dependent on third party requests, the business assumption being that these costs will not increase.

There are a number of uncertainties in relation to the impact of smart grid deployment and scale of records required to capture data, again it is assumed these will be minimal.

A small reduction of £0.7m pa across our two licence areas is forecast in RIIO-ED1.

10.2.6 Control Centre

Control centre expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	4.2	4.3	8.5
RIIO-ED1 Annual Average	3.1	2.9	6.0
Difference	-1.1	-1.4	-2.4
RIIO-ED1 Total (8 years)	**25.0**	**23.3**	**48.3**

Control centre activities include our real time operational control and system monitoring of the distribution network. Activities also include outage planning and management, dispatching of resources in response to network emergencies and safety issues, dressing and updating of network control diagrams, completion of reports for fault recording data, major incident emergency planning.

We will continue to operate two network control centres, one in each licence area, each backed up by a local disaster recovery site. Our work volumes are predominantly dictated by fault volume and planned outage activity. Increased planning activity will be required to support the increased volumes of outputs in ED1 across non load and load related programmes however this increased work will be balanced across the full year and is not expected to impact costs within the control environment. Fault volume is expected to broadly remain static as a result of various network investments.

Our control centres will face a challenge of preparing for and seizing the opportunities that smarter networks and smart metering can bring. The future data streams generated from smart technology will alter the way we operate in relation to managing our network and our customers. It is expected that such advances will require new skills to be developed within our control centre environment.

It is anticipated that our overall costs within the control centre environment will fall through RIIO-ED1 due to enhancements in our operational IT platform and associated processes including fully automated logic sequence switching and remote updating within our SCADA system. We also plan to roll out efficiency improvements in relation to LV fault management through the implementation of remote customer messaging updates and auto dispatch.

Our Control Centre costs are forecast to reduce by £2.4m pa across our two licence areas.

10.2.7 Call Centre

Call Centre expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	1.7	1.8	3.5
RIIO-ED1 Annual Average	1.5	1.2	2.7
Difference	-0.2	-0.6	-0.7
RIIO-ED1 Total (8 years)	**11.8**	**10.0**	**21.8**

We have 3.5 million customers and it is vital that these customers have a clear route to contact our company whenever they go off supply, are affected by planned outages, wish to complain or are looking for information in relation to any general enquiry.

We operate two call centres each with the ability to support the other through times of high call volumes. Our call centre activities are focused on managing the main incoming call lines used by our customers, handling initial calls, recording and handling customer information, providing information in relation to customer enquiries and handling customer complaints and ensuring our customers are passed to relevant departments within the business correctly.

Our call centres also facilitate the processing of Guaranteed Standards of Performance compensation payments, ex gratia compensation payments and ombudsman payments.

We have already instigated changes in our call centre environment by reviewing shift levels and patterns to allow development of improved working patterns and thus reducing costs.

We understand the importance of taking a holistic approach to the service we deliver for our customers and want to ensure we understand fully the experience our customers have. We are currently in the process of deploying a Customer Relationship Management (CRM) system to ensure all aspects of our customers experience are integrated whatever our customers contact us about. This will allow us to join up interfaces throughout our Business whether enquiries relate to network performance, planned works, field and contractor delivery for any other contact type.

Smart Meter Impact

At present we are unsure how smart meter technology will directly affect call volumes within our call centres. We have taken the view in this submission that any requirements to increase resource levels will be offset through efficiency.

It is expected that during the first phases of the roll out of the new technology there will be increases in the number of customer contacts. This is normal for any new technology roll out. However, equally as the smart meter programme progresses and becomes implemented then call volumes should ultimately reduce.

Smart Meters have the potential to change our customer interactions from being reactive to proactive and our business is preparing to move to a model where we are taking action on the information provided from the data flows from smart meters. For example this technology will see us notifying customers proactively during fault incidents to inform them of their expected restoration times rather than waiting on customers to call us. It will also allow us to conduct early interventions to protect customers against quality of supply issues.

Our staff will require to be trained to harness this technology and to support our customers to understand and use this new meter information effectively, as well as supporting other initiatives such as automated dispatch (made possible by smart meters).

Social Obligations

We place social responsibility at the core of what we do and have developed a clear and well defined social obligation strategy to support our commitment to our vulnerable and fuel poor customers. This is detailed in section C5g of our plan and its associated annex, Annex C5 - Social Obligation Strategy - SPEN.

The development of this strategy has been informed by our customer and stakeholder views and specifically adapted for their feedback.

Our CRM system will also allow us to manage our Priority Services Customers more easily, it will enable us to run campaigns to vulnerable customers to ensure we are able to communicate with communities such as fuel poor and allow us to write to Priority Services Register customers in line with our ED1 commitments to keep their records updated regularly.

Call Centre costs are forecast to reduce modestly by £0.7m pa across our two licence areas.

10.2.8 Stores

Stores expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	1.8	1.9	3.8
RIIO-ED1 Annual Average	1.2	0.8	2.0
Difference	-0.6	-1.1	-1.8
RIIO-ED1 Total (8 years)	**9.5**	**6.2**	**15.7**

Work on our network can only effectively be carried out with the support of the logistics team providing the necessary materials for renewing, repairing and maintaining our networks. Our logistics function manage large items of plant (switchgear and transformers), underground cable, overhead line conductors and poles as well as smaller items such as joints, overhead components and consumables.

Our materials management centres are strategically located at the centres of our two operating areas. These central locations supply materials to local depot stores who manage local stock levels and deployment of materials. Our network investment activity level drives stores throughput and our logistics processes are actively managed to optimise overall stock levels.

Our Stores costs are forecast to reduce by £1.8m pa across our two licence areas.

10.2.9 Network Policy

Network Policy expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	1.1	1.1	2.2
RIIO-ED1 Annual Average	0.9	0.4	1.3
Difference	-0.2	-0.7	-0.9
RIIO-ED1 Total (8 years)	**7.6**	**3.2**	**10.8**

Our Network Policy team complete periodic reviews of all supporting policies associated with the system taking into account the potential impact of legislative changes, operational requirements, defect and incident investigations, condition based information, research and development and changes to standards and contracts.

Network policy costs have moved from being classified as a business support cost in the DPCR5 submission to a closely associated indirect in the RIIO-ED1 submission requirements.

Network Policy costs are forecast to reduce by £0.9m pa across our two licence areas.

10.2.10 Operational Training /Workforce Renewal

Operational Training expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	3.9	3.6	7.5
RIIO-ED1 Annual Average	4.8	4.6	9.4
Difference	0.9	1.0	1.9
RIIO-ED1 Total (8 years)	**38.6**	**36.8**	**75.4**

Our business, operating and working on an electrical system, requires all staff to have the adequate skills, technical knowledge and experience to carry out their activities. Our staff must be trained and fully competent to undertake their work activities in line with agreed business processes and procedures.

On top of any initial training requirements, our staff receive regular updates on documentation changes, procedural changes and introduction of new equipment through safety stand-downs and on site/off site supplementary training. All staff must also attend safety refresher training to ensure all are kept up to date with our safety requirements.

Our plans for operational training also take account of our needs across RIIO-ED1 and into the early years of RIIO-ED2 (to 2026). Across this period it is anticipated that approximately 1700 members of staff will be retiring or leaving our Business which will require a very significant effort and clear resourcing strategy to recruit, train and retain staff going forward.

Critical to the success of our resourcing strategy is ensuring we recruit sufficient numbers of new staff through RIIO-ED1 and train them such that we have the right people with the right skills in the right place ready for efficient and effective delivery of our outputs. It is also essential to retain balance between new and existing staff within our organisation to maximise transfer of skills.

Our Business also requires our resource strategy to match the resource requirements for the future as our network evolves and the expectations of our customers increase. The skills of our staff and contractors will need to continually adapt to accommodate new solutions and new ways of working on our system. An increase in smart grid enablers such as IT, telecoms and control systems will require staff to have greater knowledge of what was previously limited to specialist teams.

Taking account of the challenges associated with growth within our industry and the changing landscape of a low carbon future, it is imperative that our resourcing strategy is fit for purpose. This may lead to recruiting and training new staff to support technology advancements, however with the resourcing challenges being faced by SPEN through attrition and retirement across this period we are provided with an unprecedented opportunity to create a recruitment, training and deployment model focused on a 21st century network.

This work has already begun in DPCR5 and was previously acknowledged by Ofgem. We have recruited 180 apprentices and 50 graduates over the last two years alone as part of our workforce renewal commitment.

We also recognise the need for ongoing development opportunities for our staff members. Through training schemes such as our Technical Craft Person (TCP) and Industrial Staff Trainee (IST) we provide the opportunity to develop strong succession plans and career paths for all of our staff.

As a result of our workforce renewal requirements Operational Training costs are forecast to increase by £1.9m pa across our two licence areas.

10.2.11 Vehicles and Transport

Vehicle expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	4.2	4.5	8.8
RIIO-ED1 Annual Average	3.4	3.8	7.2
Difference	-0.9	-0.7	-1.6
RIIO-ED1 Total (8 years)	**27.0**	**30.6**	**57.6**

We require a significant fleet of vehicles and mobile plant for our operations. The activities and costs associated with this commercial fleet are covered in this section.

Our commercial fleet has for many years been purchased and owned by oourselves. The commercial fleet is managed by a centralised corporate function with responsibility for all the ScottishPower businesses, leveraging purchasing power through higher volume .

At the beginning of DPCR5, we outsourced the provision of the majority of our plant and equipment. This decision reduces non-operational capital expenditure, allows for accurate cost reporting against work activities and reduces standing time and maintenance costs for plant and equipment not routinely used.

To enhance vehicle utilisation we have also implemented a vehicle management (masternaut) system to support business managers through the provision of detailed reporting capturing driving habits, vehicle standing time, vehicle idling amongst other parameters. The system also provides a detailed view of our vehicles in relation to activity on the system and is integral to facilitating quick response to emergency incidents.

Within SPEN there are a small number of specialist vehicles (test vans and rubber glove trucks) which will remain, these items are captured within the non-operational capital expenditure category and are covered separately.

Vehicle and Transport costs are forecast to reduce by £1.6m pa across our two licence areas.

11 Business Support Costs

11.1 Introduction

Business support (BS) costs include activities that are provided centrally that our front line staff and contractors rely upon. These may be centralised within SP Energy Networks, within ScottishPower, or in some cases within the Iberdrola Group.

These costs include the following cost categories: Human Resources, Non Operational Training, Finance & Regulation, CEO, IT & Telecoms, and Property Management.

SP Energy Networks benefits from being part of a larger global business that can deliver efficiencies of scale and increased purchasing power.

The following table summarises our business support costs forecast for RIIO-ED1

Business Support expenditure RIIO-ED1 (£m)			
	SPD	**SPM**	**SPEN Total**
HR and Non Operational	8.0	7.9	15.9
Finance and Regulation	47.1	41.1	88.3
CEO	11.9	9.6	21.5
IT and Telecoms	60.8	53.2	114.0
Property Management	24.3	18.6	43.0
RIIO-ED1 Total (8 years)	**152.2**	**130.5**	**282.7**

In developing our July 2013 business plan submission we completed a detailed benchmarking exercise across GB DNOs that identified our existing business support costs as being comparable with the average of other network operators. We also completed a benchmarking exercise across the Iberdrola Global Networks Business and Corporate model to establish best practice initiatives.

However, our focus on delivering value for customer means that we have targeted efficiency amongst the best in the industry, an average £17m lower per annum than our average cost in the period 2010-15.

Ofgem's December 2013 fast track assessment stated *"SPEN's business support expenditure appears to be efficient when compared against the DNO group benchmark and is sufficiently well justified"*

Our subsequent benchmarking analysis has indicated that our proposed business support costs remain in line with our original target to be amongst the most efficient companies in the industry.

More detail on each of the sub cost categories and the cost movements is provided below:

11.2 Human Resources and Non-Operational Training

HR and non OP expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	2.0	2.2	4.2
RIIO-ED1 Annual Average	1.0	1.0	2.0
Difference	-1.0	-1.2	-2.2
RIIO-ED1 Total (8 years)	**8.0**	**7.9**	**15.9**

Non-operational training costs represent preparation and delivery of courses other than training of field staff, including IT and telecoms training. During ED1 we will increase significantly the recruitment and training of operational field staff and refocus our organisation to become closer to our customers. The effect of these changes will be to significantly reduce our non-operational training costs.

Human Resources costs include development of HR policy and procedures, employee relations, recruitment of non-operational staff, payroll management, staff support, and costs of staff communications. The challenges we have set our business for the RIIO-ED1 period, and the support that these functions will provide, means that we expect these costs to remain broadly similar to our DPCR5 costs but with 1% per annum ongoing efficiency similar to our other costs.

Our total RIIO-ED1 forecast is £2.2m p.a. lower than DPCR5.

11.3 Finance and Regulation

Finance and Regulation expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	7.8	7.9	15.6
RIIO-ED1 Annual Average	5.9	5.1	11.0
Difference	-1.9	-2.7	-4.6
RIIO-ED1 Total (8 years)	**47.1**	**41.1**	**88.3**

Finance and regulation expenditure covers a wide range of activities grouped into five main categories:

- *Finance*
- *Insurance*
- *Network Regulation*
- *Procurement*
- *Fines and Penalties*

Finance activities include statutory and regulatory accounting requirements. During DPCR5 our statutory reporting activities have changed as we have become more fully integrated into the wider Iberdrola group. One of the most significant changes was the introduction of the SAP platform which is utilised on a group wide basis. This platform has improved cost and budget management, and helps us access economies of scale through Iberdrola's purchasing power.

The scale of regulatory reporting has grown with each price control as the Regulator has introduced greater numbers of incentives and has sought to better understand the network businesses. As regulatory reporting templates have become increasingly complex the requirement to produce reports directly from corporate systems has increased. This reduces the cost of manual intervention and risk of errors being introduced. To improve the effectiveness of our regulatory reporting, SPEN has initiated a major IT project to generate regulatory reporting and performance data from one combined data warehouse. This will ensure full transparency across our statutory and regulatory reporting platforms, will adapt to future changes in reporting format and deliver cost benefit through a reduction in manual hand-offs and interventions. It will also be a key enabler of our plans to move our network to be closer to our customers.

Insurance includes the costs of insuring against events and claims against SPEN for any damage that has been caused by our operations. This is an example of the benefits of economy of scale as within Iberdrola Group business insurance is procured centrally by a corporate function. The payments of premiums is handled centrally, costs are then allocated to the relevant country and cascaded to the business units based on a clearly defined cost allocation basis. Additional detail on our insurance strategy is included in annex C8 – Insurance Strategy - SPEN.

Network Regulation costs are associated with the interface with our regulator, and in particular:

- *Ensuring there is compliance with regulatory requirements and obligations are met*
- *Engagement with the Regulator and across the industry to develop and enhance price control mechanisms*

There are peaks of activity during price controls, but there are ongoing costs associated with industry changes, for example to reflect new EU or UK energy legislation.

Our business benefits from the global Iberdrola purchasing and procurement model, which has allowed us to procure some major plant items at significantly lower costs than other DNOs. We are reviewing all of our major contracts for the ED1 period to ensure we can transition smoothly from completing our DR5 commitments to delivering our new ED1 plans whilst ensuring that our contracts deliver value for money.

In addition to the efficiencies that will be delivered by the initiatives set out, our costs in this area are subject to 1% per annum ongoing efficiency in line with the rest of our plan.

Our forecast costs in this area are £4.6m p.a. lower than DPCR5.

11.4 CEO, Group Directors and Corporate Communication

CEO expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	2.2	2.2	4.3
RIIO-ED1 Annual Average	1.5	1.2	2.7
Difference	-0.7	-1.0	-1.6
RIIO-ED1 Total (8 years)	**11.9**	**9.6**	**21.5**

The expenditure classed as CEO costs includes costs of directors, board meeting costs, corporate communications, legal cost, company secretarial costs, and community awareness.

We will continue to support community initiatives throughout the RIIO-ED1 control period. We will increase our extensive public education programmes to spread the safety message across a wider population through:

- *"Powerwise" – classroom safety education programme delivering 4,000 teaching days to 400,000 children.*
- *Crucial Crew Events – community safety events targeting 60,000 children*
- *Fixed Safety Education Centres – "risk factory" and "danger point" which are predicted to have combined visitors in excess of 128,000 visitors.*
- *Safety Demonstrations – integrating with our farming communities at the Royal Highland Show and Royal Welsh show*
- *Continued development of our "Powerwise" internet application*

Our commitment to our customers to improve communication channels and increase customer awareness of who we are and what we do will continue to be promoted through multiple media channels.

11.5 IT and Telecoms

IT and Telecoms expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	8.4	10.1	18.5
RIIO-ED1 Annual Average	7.6	6.7	14.3
Difference	-0.8	-3.4	-4.2
RIIO-ED1 Total (8 years)	**60.8**	**53.2**	**114.0**

Costs in this area include all the operating and maintenance costs of the IT infrastructure (servers, data and telephony networks, PCs and printers) including management and applications software costs. It excludes the IT and communications systems that are used to control the network and collect data from operational sites as these are classified as operation IT & Telecoms.

Our costs for RIIO-ED1 reflect our planned efficiencies from sharing expertise, governance, applications and procurement leverage across the Iberdrola group. Major contracts for service delivery are competitively tendered by Iberdrola leveraging scale to deliver solutions and services shared globally.

Our non-operational IT & Telecoms strategy is set out in annex C6 – Non-operational IT and Telecoms Strategy - SPEN.

11.6 Property

Property Management expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	3.6	3.9	7.5
RIIO-ED1 Annual Average	3.0	2.3	5.4
Difference	-0.5	-1.6	-2.1
RIIO-ED1 Total (8 years)	**24.3**	**18.6**	**43.0**

Our property portfolio

Costs attributed to this category include rent, security, general repair and routine maintenance, utility costs, cleaning and catering services associated with our 34 offices serving our 2 million customers in Central and Southern Scotland and Berwickshire, and our 1.5 million customers in Merseyside, Cheshire, and North and Mid Wales.

Our offices and depot population are intrinsically linked to the customers we serve and provide suitable environments for office based staff, parking company vehicles and storage areas for materials.

Our 2,500 staff supported by 2,500 contractors are deployed in central offices and local depots to deliver investments and maintain supplies in an effective and cost efficient manner. This approach has delivered tangible benefits to our customers in recent years,

To meet the challenges of RIIO-ED1 we will have greater focus on a geographical delivery model that brings our organisation closer to our customers.

Our corporate Facilities team who manage our property portfolio have a track record of delivering efficient property contracts.

Our forecast costs in this area are £2.1m p.a. lower than DPCR5.

12 Non Operational Expenditure

Non Operational expenditure (£m)			
	SPD	**SPM**	**SPEN Total**
DPCR5 Annual Average	4.7	4.4	9.1
RIIO-ED1 Annual Average	6.7	6.3	13.0
Difference	2.0	1.9	3.9
RIIO-ED1 Total (8 years)	**53.4**	**50.7**	**104.1**

Costs captured within this category include:

- *the purchase of vehicles and mobile plant including generators*
- *purchase of IT and telecoms systems, and*
- *capital investments on buildings.*

12.1 IT and Telecoms

During DPCR5, we implemented a number of core IT applications:

- *Customer Relationship Management (CRM)*
- *Enterprise Asset Management*
- *Field Force Management*
- *Document Management*
- *Business Intelligence*
- *Outage & Distribution Management (Operational IT & Telecoms)*

Our RIIO-ED1 IT & Telecoms strategy will build upon these core systems, supplemented with a number of new applications and technology enablers. This accounts for £49.8m of planned Non-operational Capex expenditure over the RIIO-ED1 period. Annex C6 – Non-operational IT and Telecoms Strategy – SPEN, provides more details of the projects, which are categorised as:

- *Infrastructure & Application Refurbishment*
- *Enhancements to existing applications*
- *New applications*
- *Technology enablers*
- *Future Innovation - Smart Meter & Smart Grid*

Customers will see direct benefits in service from the investment made in our CRM system to date. We will build upon this foundation by adding customer and stakeholder self-service capability, including a fully integrated scheduling system to enable booking and scheduling of appointments.

In the short term we will also be investing in systems and solutions to allow us to be ready for the mandatory roll-out of Smart Meters and interfaces to the new Data Communication Company (DCC).

A new fully integrated work scheduling system with replenished mobile communications technology will further improve many of our field force management processes, allowing engineers and field operatives to respond to customer needs more quickly.

Also in the short to medium term we will invest in our Enterprise Asset Management, Inspection and Maintenance, Integrated Planning and Document Management systems.

Increased network monitoring capability to support the greater penetration of distributed generators and adoption of low carbon technologies by customers, plus the universal roll out of smart meters, will necessitate a capability to manage much greater volumes of data. This has driven an increase from DPCR5.

Our longer term investments will implement technologies for managing, distributing and analysing large volumes of data in order to deliver benefits for customers such as quicker connections, quicker fault repairs, and reduced costs from better informed investment decisions.

Over the course of the RIIO-ED1 period we will have a programme of continuous Product and Infrastructure upgrades to comply with vendor support and warranty requirements and technology obsolescence. We will also be implementing new technology enablers as well as introducing new technology and policies in relation to Information Security Management.

12.2 Vehicles

The purchase of new vehicles, plant and generators is treated as a capital cost. As they do not form part of the network, they are classified as non-operational

The majority of vehicles and small plant used by us is leased as this has proven to be the most cost effective sourcing method. These lease costs are captured against the activities with which they are associated.

It is more cost effective to purchase specialist vehicles such as high voltage test vans, high voltage overhead line live working trucks and trenchless excavation rigs. A small proportion of this expenditure maintains the fleet of vehicles at current levels.

The proposed changes to Guaranteed Standard EGS2 will mean a greater reliance on the use of mobile generation to allow restoration of supplies in less than 12 hours. We have developed a generator strategy which will deploy greater numbers of generators from our local depots than our current approach which relies more heavily on leased generators. As a result, our costs are forecast to increase in this area for the purchase of mobile generators, but our lease costs will reduce.

12.3 Property

A 10 year plan is maintained based upon individual site condition information, maintenance records, meeting existing and new legal obligations, and improving our environmental impact. These factors are considered in the cost benefit decision to refurbish aging buildings or relocate to new sites.

The ScottishPower Group operates from a number of owned and leased properties within the central belt of Scotland, Merseyside, Cheshire and North Wales. A number of the owned properties now need capital investment as mechanical and electrical systems are reaching the end of their useful lives. In addition a number of the leases will expire over the next 9 years.

Our strategy in relation to sites delivering central services is to consolidate to deliver operational efficiencies and savings in overall property costs. Our most recent strategic property initiatives are the development of our new out of town office, Ochil House at Hamilton International Park, together with the construction of a new headquarters property in Glasgow. In both shared sites of Ochil House and Scottish Power business headquarters, strong business separation measures have been incorporated into the overall building design and layout.

12.4 Environmental Compliance

We place significant focus on developing energy efficient sites minimising our environmental impact. All new developments and those receiving major refurbishment are expected to achieve high standards of energy efficiency.

The operational costs of Ochil House are lower than that of our previous main office, New Alderston House, which was vacated in September 2013. Our newly built office has an Energy Performance Certificate of B+, reducing our business carbon footprint and supporting our environment outputs.

All of our locations are covered by our ISO 14001 accreditation. We take pride in our commitment to maintaining our certification, with accredited auditors assuring our stringent compliance.

12.5 Small Tools and Equipment

Our craft and engineering staff require tools and equipment to operate on the network. We ensure all correct tools and equipment are available including hand tools, test equipment for commissioning and fault location, machinery to enable refurbishment of components and plant, and lifting and tension tools for overhead line work.

In general these tools are replaced on a needs basis as items become worn or when specific new tools designed to improve the health and welfare of our staff become available.

13 Smart Metering Costs

Smart Metering		DPCR5	RIIO-ED1	
		£m pa	£m pa	RIIO-ED Total
Smart Metering	SPD	0.2	1.8	14.6
	SPM	0.2	1.4	11.2
Total		0.4	3.2	25.8

The government has set a target for Electricity Suppliers to install a Smart Meter in every UK domestic and SME premises by the end of 2020. This programme is expected to increase the number of service positions each year requiring remedial works by network companies. . We have used a cut-out replacement rate of 2% of smart meter installations per year, as per recent discussions with OFGEM.

Our service position activities (cut out changes, mural wiring and rising and lateral mains works) have been designed with the Smart Metering installation works firmly in mind:

- *Recognising the importance of easily accessible and clearly identifiable means of local isolation to meter installers.*
- *End of life equipment in our programmes are likely to be areas where meter installers would have difficulties.*

Where our modernisation works are completed, we do not expect there to be any issues that would delay the roll out. However, as the Smart Metering programme is Supplier led, works will be required in areas where our investment activities have not been completed and our existing programmes will need to be re-directed or accelerated accordingly.

Smart meters will provide useful data that will enable network operators to provide a better customer service and better understand the behaviour of the low voltage network. In order to utilise this data, it will be necessary to interface our systems with the Data Communication Company (DCC), the central organisation established to process and distribute smart meter data to the relevant users. Our plans include the IT investments to develop and manage these interfaces.

We will use the data from smart meters to transform our relationships with customers:

- *Contacting customers proactively when faults occur*
- *Using information to improve our response times and efficacy*

We expect the use of smart meter data will produce a range of benefits for both SPEN and our customers. Short term benefits are likely to be in customer service and fault management with longer term benefits in areas of design and network management process improvements.

Smart Metering Benefits	RIIO-ED1	
	£m pa	RIIO ED1 Total £m
Accrued benefits	1.1	8.7
Societal benefits	1.75	14
Total	1.85	22.7

14 Non Activity Based Costs

Non activity based costs include:

- *Corporation tax*
- *Business rates paid to local government*
- *Transmission charges paid to National Grid*
- *Central smart metering system costs*
- *Legacy pension costs.*

Within our plans we have included £1.179bn to cover these costs (£718m SPD, £461m SPM). These are all external costs that we do not control. For more information please see Chapter C8, Uncertainty and Risk.

15 Real Price Effects

Real Price Effects (RPEs) are the difference between the index that is used to update our revenues each year (the Retail Prices Index, RPI) and the movements in the costs of materials (for example, copper cables) or specialist labour (for example, engineers).

Our forecast of real price effects and on-going efficiency for RIIO-ED1 are:

- *Real price effects of just over 1% per annum, on average,*
- *Offset by ongoing efficiency of 1% per annum*

We engaged First Economics to update their forecasts of real price effects (Annex 3.2). First Economics' previous forecasts were used by WPD in their RIIO-ED1 business plan, which Ofgem has fast-tracked.

First Economics have taken into accounts comments made by Ofgem in their November 2013 assessment of DNOs' RIIO-ED1 business plans and by the Competition Commission (CC) in its provisional findings in the Northern Ireland Electricity (NIE) price control inquiry.

First Economics adopt a two-step approach, which first estimates the expected rate of nominal input inflation and then subtracts the expected rate of RPI inflation. This is consistent with the approach that the CC used in its provisional determination for NIE.

First Economics use the most recent (i.e. December 2013) Office of Budget Responsibility (OBR) economic forecasts as the basis for their forecasts. This is again consistent with the approach that the CC used in its provisional determination for NIE.

First Economics' RPE estimates are summarised in the following table:

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20 to 2022/23
Labour – general (%)	(0.2)	0.3	0.7	0.7	0.4	0.85
Labour – specialist (%)	1.1	1.6	1.9	1.9	1.6	2.1
Materials – general/civils (%)	1.5	1.1	0.9	0.7	0.5	1.1
Materials – electrical (%)	2.0	1.6	1.4	1.2	1.0	1.6
Plant and equipment (%)	(0.5)	(0.9)	(1.1)	(1.3)	(1.5)	(0.9)
IT (%)	(2.25)	(2.65)	(2.85)	(3.05)	(3.25)	(2.65)
Property rentals (%)	(0.5)	0.0	0.0	(0.1)	(0.3)	0.85

On-going efficiency

The ongoing efficiency assumption within our business plan is 1% per annum. As set out throughout this chapter, we have reviewed in detail direct and indirect costs to ensure our plan is efficient. In addition to establishing our base costs, a 1% year on year on-going efficiency challenge is embedded across labour, contractor and material costs in our business plan. We believe this is an aggressive assumption and the independent report from economic consultants Reckon supports this view.

Reckon LLP independently reviewed historical data on comparable efficiency gains and the results of their review are presented in Annex C6 – Real Price Effects 2014/15 to 2022/23 – Firts Economics.