Well Justified Business Plan

2015-2023

March 2014

electricity north west

Bringing energy to your door

Our promises to the people of the North West 2015-2023

- **Customers are at the heart of our business**

  All our customers will experience a first-class service whenever they need us

  We will expand our services for vulnerable customers, providing an even greater level of support than we do today

- **Our prices are coming down**

  Our average prices between 2015 and 2023 will be 16% lower than they currently are

  Our prices in 2014 will be held constant to 2015 and then will reduce by 18%

- **Our network will be more reliable**

  We will reduce the number and duration of power cuts by 20%

  We will ensure none of our customers will be classed as 'Worst Served' by Ofgem

- **Our network will meet future challenges**

  We will make sure customers can connect low carbon technologies when they need to

  We will help the UK meet it's ambitious carbon reduction targets

Welcome

I am delighted to share with you our RIIO-ED1 Well Justified Business Plan for 2015 to 2023.

We all depend on electricity – it is the invisible force that powers our daily lives. We rely on it for the basics such as heat and light, essential services such as hospitals, schools, airports and our regional businesses and to power the little luxuries we all enjoy.

The future of our electricity network and how we operate it matters to us all. That is why we have talked to you extensively about the complexities of our business and industry and the major challenges we face in the future. Only by involving you in our decision-making can we ensure we have a network that meets the needs of us all. Our plan for the future is a plan for you, a plan for all of us in the North West to ensure our region has a world class network that can meet the challenges of our changing world safely and efficiently.

We asked you, our customers and stakeholders, for your opinions and views. You responded in your thousands, providing us with a detailed understanding of what you expect from us. You expressed many different views, but a number of common themes appeared time and time again. And it is these key themes which have shaped our plan for the future.

You said you want our network to be **reliable**. You expect us to keep the lights on 24 hours a day and seven days a week and this is what we simply must do. We have therefore committed to making our network 20% more reliable than it is today.

You said you want our network to be **affordable**. We understand that increasing energy bills are a worry for us all. We have challenged every aspect of our business and as a result we are committing to average prices which will be 16% cheaper than they are today.

You said you want our network to be **sustainable**. We are investing sensibly to make sure our network meets your needs today whilst recognising the challenges of the future. Our plans are flexible and responsive so we can meet the challenges of connecting Low Carbon Technologies.

Alongside all this, you quite rightly expect excellent **customer service** when you do need to speak to us. This is exactly what we will provide and are putting our customers at the heart of everything we do.

Since we published our initial well justified business plan in July 2013, we have made a number of changes to our plan to respond to feedback from customers, stakeholders and Ofgem. The changes to our plan result in a £76 million reduction in our revenue. Overall, the impact on prices that will be paid by domestic customers as a result of our new plan is a reduction of £19.72 (or 18%) from 2014-15 to 2015-16 and further small falls thereafter.

I want to take this opportunity to thank you all for your input. This is a plan for all of us and for the future of our network. The years to 2023 will be an exciting and challenging time for the industry as we adapt to a changing world – but I want to personally assure you that you can depend on us to deliver an even safer, more reliable and efficient service in the years ahead.

Steve Johnson

CEO

Electricity North West

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Our plan - section-by-section

Section 2 sets out an overview of our company and the key challenges we face.

Section 3 describes the process we have used to engage with our stakeholders, decide what we will deliver and how we will deliver it.

Section 4 covers all of the Outputs we are committing to deliver.

Section 5 explains what delivering these Outputs will cost and how we have ensured that costs and volumes are efficient.

Section 6 details how the plan will be financed.

Section 7 describes how we have addressed risks and uncertainty.

Section 8 explains the innovation programme we are using to support the plan.

1 Executive Summary

Electricity North West Limited is the electricity distributor for the North West of England. We own, invest in, operate and maintain the network of overhead lines, transformers, switchgear and underground cables which carry electricity from the national grid to our customers in every home and business in the North West.

1.1 Our job is to keep electricity flowing to our customers' homes and businesses, keeping the lights on 24 hours a day, seven days a week.

1.2 We recover our costs by charging electricity suppliers for the use of our network. Our charges account for about 16% of the average domestic electricity bill.

1.3 Ofgem (Office of Gas and Electricity Markets) regulates the amount we can charge through a series of price controls. We are currently in DPCR5, the fifth price control since privatisation, which covers the five years from 2010 to 2015. In 2015, DPCR5 makes way for RIIO-ED1, a new eight-year price control framework, which runs from 2015 to 2023. The RIIO framework links our Revenue to Incentives, Innovation and the Outputs we deliver for our customers.

1.4 Our Well Justified Business Plan details our proposals for the RIIO-ED1 price control.

Our Promise: Prices

1.5 We understand that the cost of energy is becoming increasingly difficult to bear. We think the best way to deal with this is to keep prices down. If Ofgem accepts our proposals:

- We can reduce our average prices by 16% compared to DPCR5 and kick-start RIIO-ED1 with a price reduction of 18% in 2015-16.

1.6 We can do this because we operate an efficient business. Our prices in RIIO-ED1 will be among the lowest in our industry. We will achieve this through our continued commitment to cost and productivity improvement, development of innovative solutions to the problems we face today and in the future and benchmarking our performance against our industry peers and the wider competitive market.

Our Promise: Customer Service

1.7 We will provide excellent customer service for all our different customer groups. We will make sure customers can contact us quickly and easily through the most convenient channel for them. We will provide them with accurate and timely information and take ownership of their issues.

1.8 Telephone contact is likely to remain the favourite channel for the foreseeable future and we will invest in our people, systems and processes to deliver a first class telephone service. We will answer all calls quickly and make it easy for our customers to speak to one of our Customer Service Agents if they want to. We will resolve at least 90% of customer enquiries the first time they contact us and resolve all complaints first time.

1.9 We will support our telephone channel with online, mobile and app channels which will provide real-time information on, among other things, faults, their causes and expected restoration times.

1.10 Stakeholder engagement is embedded in our business and we will continue to build upon our already successful engagement to make sure we respond to our stakeholders' changing needs.

1.11 We will deliver additional assistance to our vulnerable customers in each year of RIIO-ED1. We will support this direct assistance with a co-ordinated programme which brings together companies, agencies, charities and other groups in the North West to develop integrated plans to help address fuel poverty.

Our Promise: Network Performance

1.12 Our network is one of the most reliable in the country. Since we acquired the business in 2007, we have reduced the number of power cuts our customers experience (called Customer Interruptions) by 16% and their average duration (called Customer Minutes Lost) by 18%.

1.13 We are investing £1.4 billion during DPCR5 to improve reliability, ensure capacity and deliver a safe network. We plan to invest a further £2.6 billion in RIIO-ED1 to ensure the network continues to deliver excellent, affordable service to our customers in the face of future uncertainty.

Our Promise: Fit for the Future

1.14 Our investment plans are prudent but flexible. We will invest the right amount at the right time to make sure we can improve performance now and sustain it in the long term. We will design our interventions to balance performance and value in a way which does not store up problems for future generations.

1.15 We are committed to supporting the UK's transition to a low carbon future. We will use a combination of traditional reinforcement and innovative commercial and technical arrangements to provide sufficient capacity to accommodate Low Carbon Technologies.

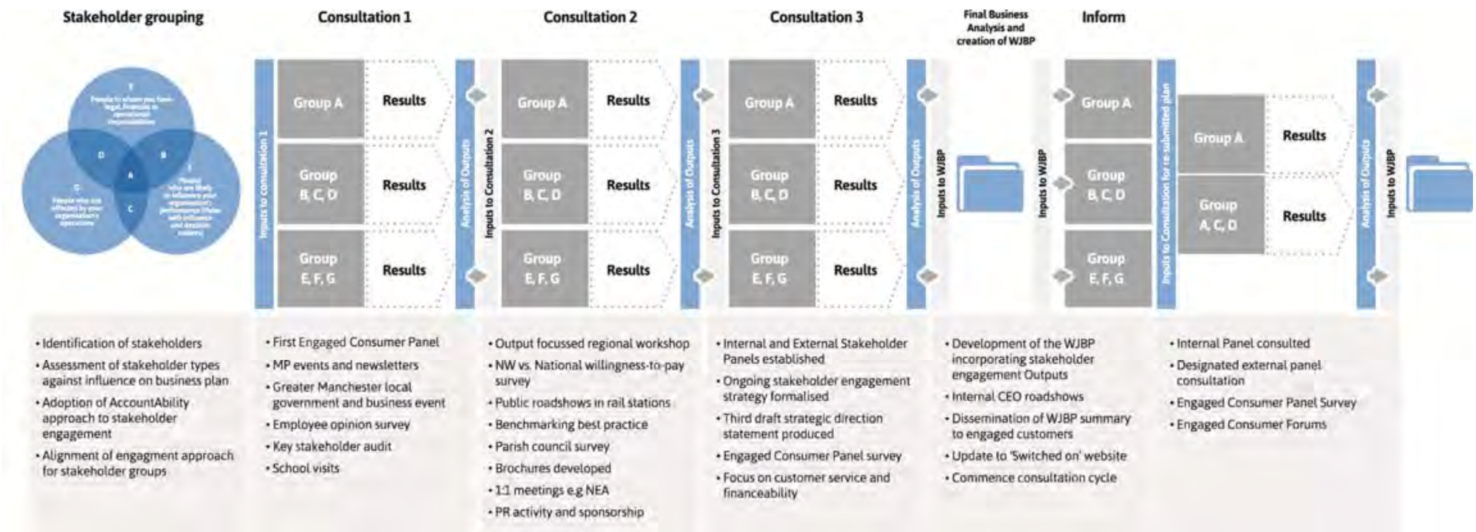
1.16 When customers want to connect to our network, we will make this easy, quick and affordable. We will provide consumer choice by continuing to champion a fully competitive connections market.

1.17 We are very proud of our Well Justified Business Plan. It delivers outstanding value, performance and service for our customers and stakeholders. It clearly demonstrates that our costs and prices are reducing, our performance and service is improving, we are innovating to respond to the challenges of the future and we are delivering the Outputs our customers and stakeholders value most.

Developing our Business Plan

Stakeholders have played an essential part in helping us develop our plan. They range from the domestic and commercial customers who depend upon our service, to local and national government and groups who represent various specific interests.

1.18 We have consulted widely through our 'Switched on: North West' campaign to better understand our stakeholders' needs and priorities. We have analysed them, provided feedback, developed proposals and consulted upon them through an audited and accredited process, which is shown in the diagram below:



1.19 This is the second version of our Well Justified Business Plan. Ofgem reviewed the previous version during the second half of 2013 and found it met four of their five key criteria.

DNO Group	licensee[10]	Process	Outputs	Resources – efficient costs	Resources – efficient finance	Uncertainty and risk
Western Power Distribution	WMID					
	EMID					
	SWALES					
	SWEST					
Electricity North West Ltd	ENWL					
Northern Powergrid	NPgN					
	NPgY					
UK Power Networks	LPN					
	SPN					
	EPN					
SSE Power Distribution	SSEH					
	SSES					
SP Energy Networks	SPD					
	SPMW					

1.20 However, Ofgem asked us to look again at our expenditure forecasts as they found that we had not fully justified the previous version.

1.21 In this version of the plan we have reviewed the entirety of our expenditure proposals, benchmarked ourselves against the other DNOs using the data Ofgem provided and worked with our supply chain to review key unit costs.

1.22 As a result we have been able to reduce our expenditure by a further £34 million. We have also provided considerably more detailed information that explains why the investments we are making are the most efficient for the people of the North West. In particular we have provided a lot more detail on how our plan develops and deploys the benefits of smart meters and smart grids.

1.23 Where we have received feedback from Ofgem on the previous version of our plan we have checked many of the changes in this version with stakeholders before finalising this plan.

Stakeholder Priorities

1.24 We have many different stakeholders and, not surprisingly, they express a wide range of needs and expectations. We would like to be able to accommodate them all, but in truth it is neither practical nor cost effective to do so. Our engagement process allowed us to gather, analyse and refine stakeholder input to our plan to determine the major issues which had the most support.

1.25 They are:

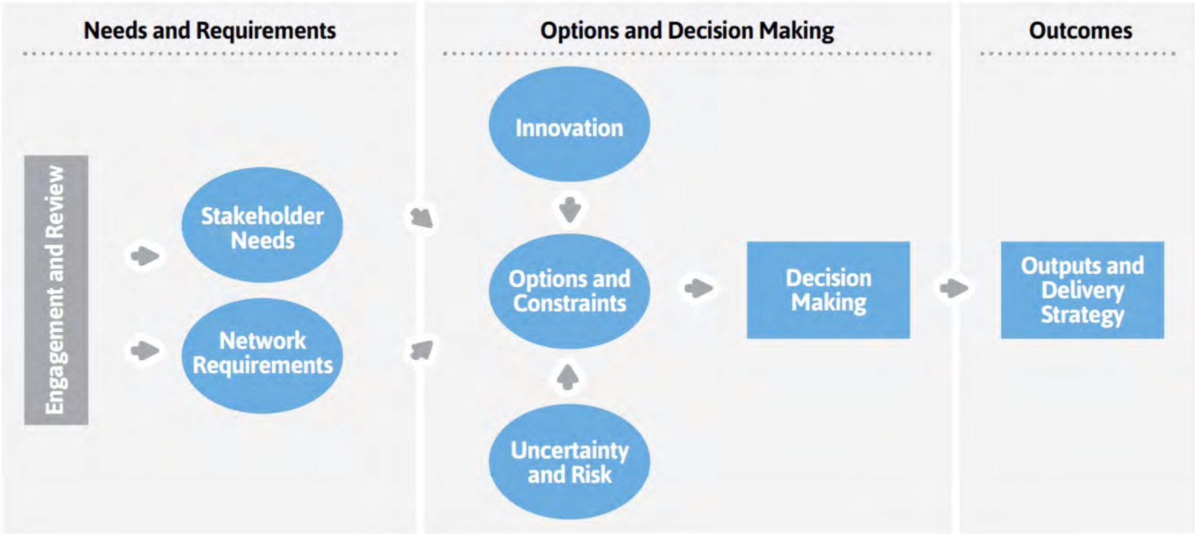
- Reliability – 'keeping the lights on'
- Affordability – delivering exceptional value for money
- Sustainability – managing and investing in our network to meet the challenges of the future

1.26 Our customers expect and demand a first class service when they need to contact or interact with us. We are responding to this by putting customers at the heart of our business and we promise to deliver their priorities with an exceptional level of Customer Service.

1.27 These "Stakeholder Priorities" are the foundation of our plan.

Process

1.28 Our entire business has come together to develop our plan. It is based on a robust and comprehensive decision-making process and a governance plan overseen by our Chief Executive Officer and Board. Our process is illustrated below:



Assessing Needs

1.29 Our starting point is to look at what we need to deliver to meet customer and stakeholder expectations and to maintain the safe, efficient and reliable operation of our network.

1.30 Stakeholder needs come from our Stakeholder Engagement process. Network needs are determined by a number of factors, including asset age, condition and capacity as well as an assessment of the electricity our network has to distribute now and in the future.

Options and Decision Making

1.31 We can satisfy stakeholder and network needs in a number of ways and we use robust and proven techniques to develop the right mix of interventions. Our decisions have been guided by our Stakeholder Priorities, engineering experience and standards and decision support techniques like Condition-Based Risk Management and Cost Benefit Analysis.

1.32 Sometimes there is no established solution so we rely on our strong track record of innovation to develop new, cheaper and faster ways to solve problems.

Outcomes

1.33 Our process results in a detailed programme of interventions and services which range from minor repairs to huge capital projects; from developing training programmes for our Customer Service Agents to replacing the IT systems which let us manage our network. The RIIO framework lets us express this complex programme in a series of ‘Outputs’, which are essentially the performance and service levels we will deliver for our customers and stakeholders in RIIO-ED1.

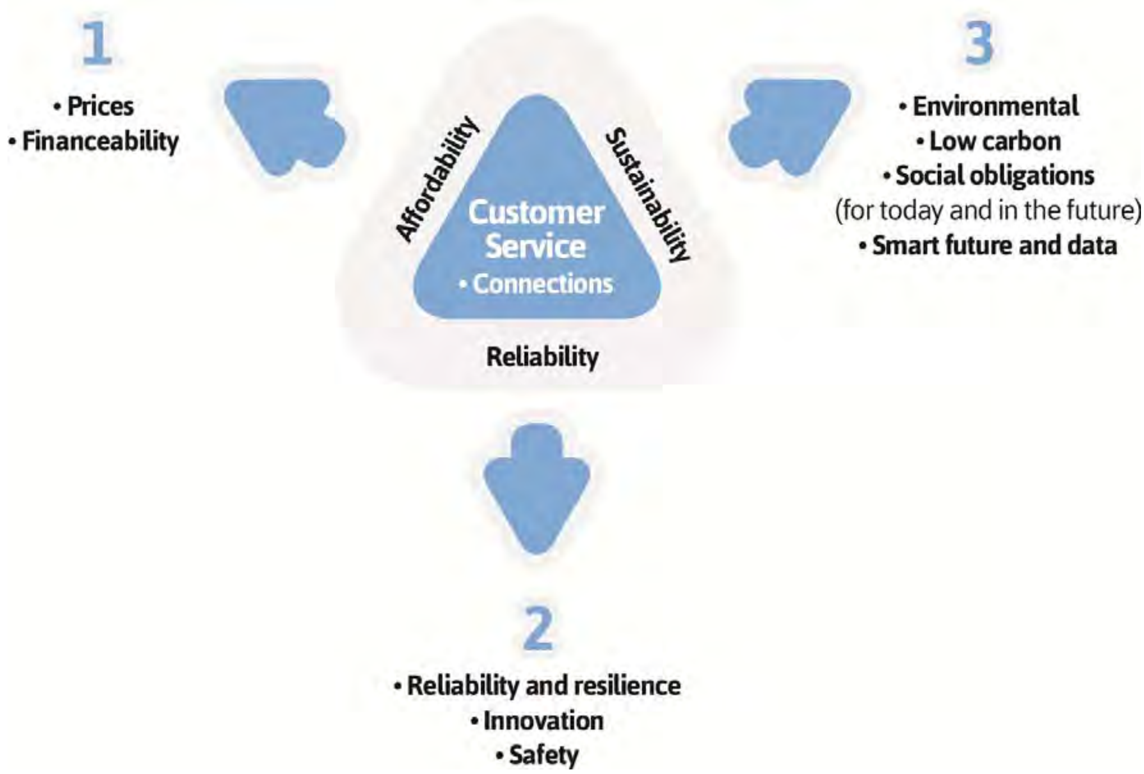
1.34 The Outputs are:

- Safety
- Social obligations
- Reliability and availability
- Customer satisfaction
- Connections
- Environmental impact

1.35 Our Outputs will deliver an exceptional level of price, reliability and sustainability benefits which provide excellent value for our customers and support our collective ambitions for a low carbon future.

Responding To Stakeholder Priorities

Our plan is complex but can be expressed by a small number of key attributes, which we have aligned to our Stakeholder Priorities.



Customer Service

1.36 Customers tend to contact us either when their electricity supply is interrupted or when they need to connect to our network. When they do, they expect us to provide accurate and timely information and deal with them in a professional and helpful way.

1.37 We are investing in our people, systems and processes to make sure our customers experience excellent service every time they contact us. Our target is a minimum score of 85% in the Broad Measure of Customer Service.

1.38 Our connections Output proposals are at the forefront of our industry. We will make it easier, cheaper and quicker to make a connection application and to carry out the work. We will invest to make sure our network can accommodate low carbon technology connections, both large and small, and use innovative approaches to overcome network capacity constraints.

Affordability

1.39 Our entire plan ultimately results in a price we have to charge electricity supply companies for the use of our network. Customers are increasingly worried by rising energy prices and the burden this places on household and business budgets. We have worked hard to improve our efficiency and productivity to minimise our costs and our customers will benefit from this.

1.40 We have developed a financing package which lets us meet our obligations, maintain a good credit rating and raise the money we need to pay for our investments. We believe we have struck an excellent balance between the allowances we need to meet our funding costs, the additional capital that our shareholders will invest and the incentive revenue we can earn from excellent performance, which is fair for our customers and us.

Reliability

1.41 Our stakeholders want us to 'keep the lights on' by operating a safe, efficient and reliable network. Safety is our number one priority. We will comply with all applicable legislation and go beyond this with selective, targeted investment to address specific risks to our staff, contractors and the public.

1.42 Our network is already 99.99% reliable but we want to go further. Our stakeholders would like 100% reliability. This would mean us doubling the size of our network to make sure we had a back up when a cable, transformer, switch, pole or tower developed a fault. This would be unaffordable. Instead, we propose to improve network reliability by 20% from its 2012 level by 2019.

1.43 We have already demonstrated an enviable track record in applying innovation to solve practical problems on our network and improve reliability and service. We face many new challenges in the future, particularly from the adoption of Low Carbon Technologies (LCT), and we will continue to innovate to make sure our customers can benefit from the cost and performance benefits LCT can deliver.

1.44 We will continue to develop our resilience programme to protect the network from extreme weather events, particularly flooding.

Sustainability

1.45 Our customers want a network which delivers reliable service now and in the future. They trust us to make the right engineering and asset management decisions but they want us to do so in a way which balances the cost across the generations of customers who will benefit. We agree with them. We could radically reduce investment in the short term to create artificially low prices but we think this would be reckless and mean storing up problems for future customers. Our investment programme is prudent and consistent.

1.46 We are a responsible organisation and we take our environmental and social obligations seriously. Our sustainable network will be one which helps deliver the UK's ambitious greenhouse gas emission reductions by enabling LCT adoption, reducing the losses inherent in electricity distribution and contributing to a substantial reduction in our own Business Carbon Footprint. We believe that smart meters and other smart technology can contribute as well and our plan demonstrates our readiness to play our role in the Smart Future.

1.47 We believe that our plan meets our customers' and stakeholders' key requirements however we recognise that there are some customers who need extra support and assistance from us. We are upgrading network reliability in areas where there are concentrations of vulnerable customers and will provide temporary power supplies for our most vulnerable customers during power outages. We provide our vulnerable customers with a welfare support package when they need it. We are supporting this with a comprehensive Customer Relationship Management system. This will help us target this assistance effectively and support greater coordination among organisations in the North West to address fuel poverty.

Outputs

Outputs are the products and services we will deliver for our customers and stakeholders in RIIO-ED1. Ofgem has specified six Outputs and asked for our proposals for each. In some cases we go beyond the basic Output and propose additional deliverables which are needed to address specific issues.

Safety

1.48 Safety is our number one priority. It is embedded in everything we do as a business. Our Safety Output delivers absolute compliance with all relevant legislation and regulation. In addition, we will take steps to address specific risks to staff, contractors and the public by:

- Improving security arrangements at 800 substations to reduce metal theft and vandalism
- Installing additional safe climbing attachments on 1,600 towers
- Removing or making safe the asbestos in 9,000 substations

Social Obligations

1.49 We are a responsible organisation. We take our role in the social development of our community seriously and our Social Obligations Output commitments reflect this.

1.50 We will participate in the Business in the Community Corporate Responsibility Index and achieve Gold status by 2019.

1.51 Some of our customers need a bit more support from us when their electricity supply is interrupted. We already maintain a Priority Services Register to allow us to assist these customers. We will go further to provide enhanced support for all vulnerable customers. This will include meals and other welfare provisions, personal support from our staff or our partners at the British Red Cross and temporary generators where there is an urgent need to restore supply.

1.52 We are developing a comprehensive Customer Relationship Management system which will allow us to better understand our customers' relationships with our business. This will allow us to develop targeted and effective support. Our staff will be trained to recognise signs of vulnerability and when they do, explain the additional services and support we can offer.

1.53 We will deliver a programme of automation to improve the reliability of the network where there are large concentrations of vulnerable customers.

Reliability and Availability

1.54 This is the measure of how well we 'keep the lights on' and, when they go off, how quickly we get them back on again. We do this through a combination of investment, automation and responding to faults.

1.55 We will improve Reliability (measured by Customer Interruptions) and Availability (measured by Customer Minutes Lost) by 20% of their 2012 levels by 2019.

1.56 We can only deliver this improvement if we maintain the underlying stability and resilience of our network. We therefore need to continue to invest in maintaining our current network. Our network investment, maintenance and replacement programme will maintain network risk (ie the probability of asset failure) within 3% of its 2015 level and we will maintain our current fault rate.

1.57 We will install additional capacity or interconnection at major substations where there is a risk of overloading and provide capacity for LCT connection by replacing switchgear at locations where it is likely to be a constraint.

1.58 We will improve resilience to extreme weather events and malicious attack by a programme of flood protection, network reconfiguration, additional battery back-up capacity and security measures.

1.59 By 2023, no customers connected to our network will fall within the industry definition of 'Worst Served'.

Customer Satisfaction

1.60 We are committed to delivering the highest level of service for our customers.

1.61 Ofgem's Broad Measure of Customer Service measures our performance on general enquiries, complaints and connections enquiries. We will achieve a score of at least 85% against this measure at the start of RIIO-ED1 and maintain or improve it for the duration of the price control.

1.62 We will resolve all complaints first time. At least 90% of these will be within one working day and the remainder within five working days.

1.63 We will continue to develop our Stakeholder Engagement process and ensure our plans take account of our stakeholders' and customers' changing needs.

1.64 Despite our best efforts, there will be times when we do not meet our customers' expectations in full. Where this is the case, we will proactively pay any compensation they may be due under Guaranteed Standards.

Connections

1.65 When customers want to connect to our network, we will make the application and delivery process easy, quick and as affordable as possible.

1.66 We will continue to champion a fully competitive connections market and implement a comprehensive strategy to support our major connections customers. Ofgem can penalise us where our engagement falls below expectations. We will ensure our engagement is professional, courteous and proactive and therefore expect not to incur any penalty.

1.67 When customers ask us for a connection quotation we will provide this within:

- Six working days for single domestic connections
- Ten working days for two to four domestic connections
- Twenty-five working days for all other connections

1.68 Once we have agreed terms with customers, and they tell us they are ready to progress, we will complete the work within:

- Thirty working days for single domestic connections
- Forty working days for two to four domestic connections
- Fifty working days for all other connections

Environmental Impact

1.69 We are determined to make a positive contribution to our environment.

1.70 Our Business Carbon Footprint measures the amount of carbon we emit. In RIIO-ED1 we will reduce it by 10% of its 2015 level by 2020.

1.71 We will invest £10 million in low loss transformers, which will help reduce the amount of electricity which is lost as a natural result of the distribution process. Our investment will reduce losses across our network by 11,000 MWh, equivalent to 4,900 tCO_2e, each year.

1.72 We use oil to insulate some of our transformers and cables. Inevitably some of this leaks so we will take steps to reduce oil leakage from our cable assets by 13% compared to DPCR5 levels.

1.73 Our network passes through some of the most breathtaking landscapes in the country. Some of our stakeholders would like us to run as many of our cables as possible underground where this is the case. Although we cannot do this for the entire network, we will underground 80km of overhead lines in National Parks and Areas of Outstanding Natural Beauty for a cost of £9 million.

Expenditure

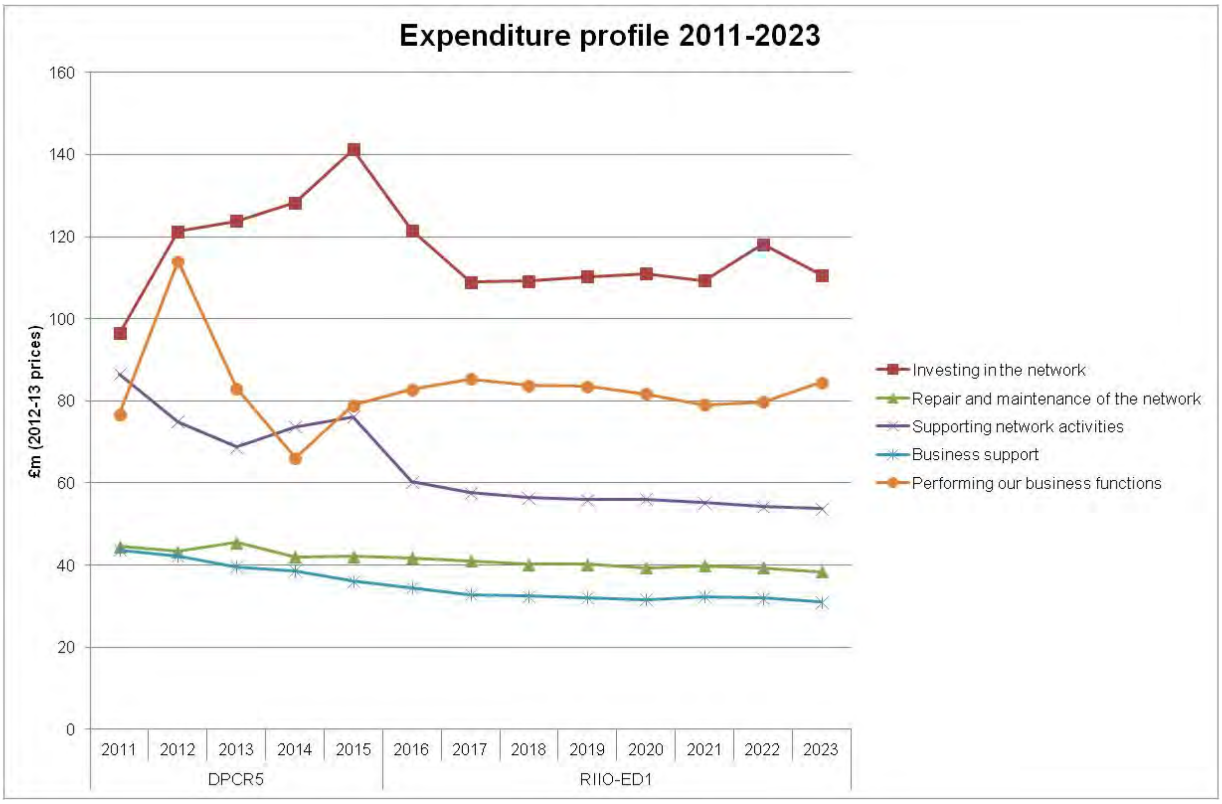
In RIIO-ED1, we will invest around £2.6 billion in maintaining, replacing and upgrading our network and carrying out all the other functions expected of us as a responsible business.

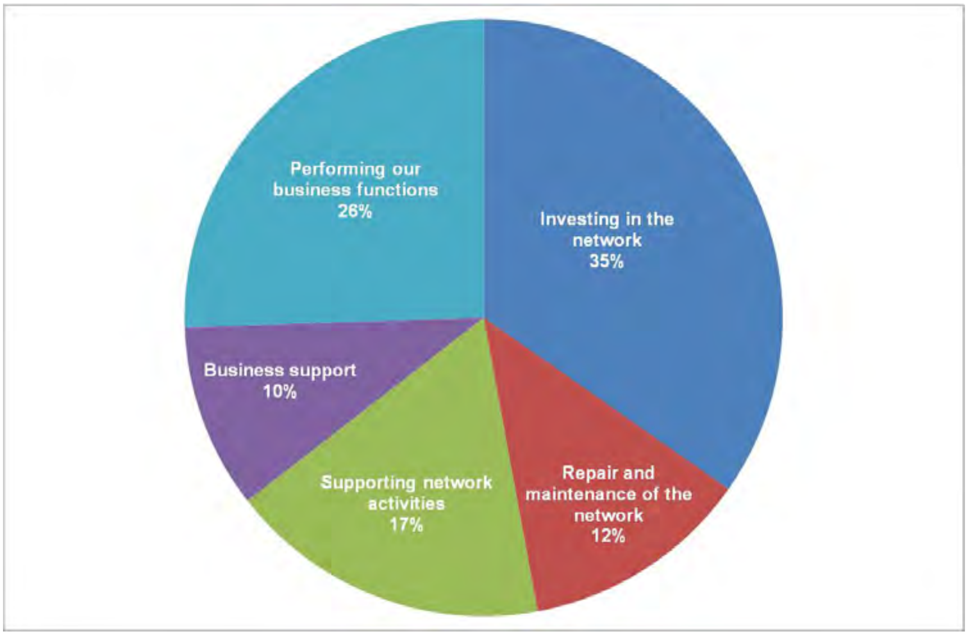
1.74 Our expenditure is broken down into five main areas:

- Investing in our network
- Repair and maintenance of our current network
- Supporting network operations and investment
- Business support
- Performing other business activities

1.75 We have challenged ourselves to reduce costs and improve efficiency and benchmarked our ambitions against other DNOs and the wider asset management and service sectors. We believe our plans are cost-effective, efficient and flexible and deliver outstanding value for our customers and stakeholders now and in the future. We recognise that we need to continue to challenge costs and efficiency and so are committing to reduce our costs by at least 1% year-on-year in RIIO-ED1.

1.76 The overall impact of this is to reduce our costs by £76 million compared to maintaining at 2015 levels.





Investing in our network – £899 million

1.77 This is our biggest area of expenditure and accounts for 35% of our RIIO-ED1 total. This is broadly in line with our level of investment in DPCR5.

1.78 Our stakeholders want an efficient, reliable and resilient service and we will invest to deliver this. We will create capacity to accommodate expected economic and social changes in the North West and enable adoption of Low Carbon Technologies. We will continue to invest in and deploy innovative solutions which allow us to improve our service and reduce our costs.

Repairing and maintaining our network – £320 million

1.79 We invest to make sure our network remains fully operational and aligned to our customers' needs. We will respond rapidly to fix faults, inspect and maintain the equipment regularly, manage the vegetation growing near our lines and operate the substations on which the major plant is sited. Our continued commitment to efficiency and service means these costs will be 8% less than in DPCR5.

Supporting network investment and operations – £449 million

1.80 Managing our network requires considerable support activity, whether through the delivery of capital works or providing the capability to manage day-to-day operations. We run a state-of-the-art Control Centre to manage network service and a Customer Contact Centre to support customer service. We invest to find new ways of doing things and manage a range of non-operational assets, such as vehicles and buildings. On-going challenge and rationalisation of our support activities means these costs will reduce by 26%.

Business support activities – £259 million

1.81 There are a range of things we have to do to fulfil all our obligations as a major business. We need to recruit, train and develop our people; manage and operate our business IT systems; report our activities appropriately; comply with our legal and regulatory obligations; raise finance to fund our investment and operations and play an appropriate role in the community. We look to reduce these costs wherever we can. Following feedback from Ofgem we have committed to additional reductions in business support costs. As a result, the proportion we spend on business support has been reducing and in RIIO-ED1 we are committing to an 18% reduction compared to DPCR5 levels.

Performing our other business activities – £660 million

1.82 We incur cost obligations as part of our operations including transmission connection point charges, the Ofgem licence fee and pension deficit repair costs. There are also other services that we provide to a variety of customers that are charged for separately and our plan includes the costs we will incur in providing these. These services include diversions, where we have to move our assets; where a customer wishes to move their meter position and revenue protection activities to combat electricity theft. Over RIIO-ED1 these costs will be broadly similar to those in DPCR5 due to the accommodation of new requirements such as smart metering roll out.

Financing Our Business Plan

Ours is a long-term business. We invest in, maintain and manage assets which will deliver for our customers and stakeholders over many decades.

1.83 We need to pay for equipment, supplies, labour and services when we install and use them however we recover these costs over a much longer period. This creates a significant mismatch in our cash flows. We bridge this gap by raising the capital (cash) we need to invest and operate through a combination of shareholder investment (equity) and borrowing (debt).

1.84 Under our licence from Ofgem we need to maintain an 'Investment Grade' credit rating, which allows us to access the global capital markets and helps us negotiate efficient interest rates on our borrowing. We plan to maintain our credit ratings at the existing Investment Grade levels throughout RIIO-ED1.

1.85 Ofgem has introduced a 'Trailing Average' index to set the Cost of Debt allowances for RIIO-ED1. For a number of reasons, we are concerned that the Trailing Average will mean a material shortfall in the funding of our efficient actual Cost of Debt. We need to construct a fair and sustainable financing package, which maintains our Investment Grade credit rating and offers value for our customers. We have, therefore, embraced the Trailing Average index concept, using an average over that last 15 years that focuses on the investment grade level.

1.86 Our core financeability proposals are:

Cost of Equity	6.3%	This recognises the recent changes Ofgem have identified in the cost of equity
Cost of Debt	15 – 20 year Trailing Average	We can accept this as part of our balanced finance package
Gearing	65%	This is the same as DPCR5 and we see no need to change it
Capitalisation Rate	72%	This is in line with our statutory capitalisation rate

1.87 In order to maintain our Investment Grade credit rating, we need to supplement the core proposals with some additional measures. We propose to transition to Ofgem's 45-year asset life over the course of RIIO-ED1. The average asset life will be 34 years. We have deferred £11 million of revenue from DRCR5 to RIIO-ED1. Ofgem have agreed to certain license condition changes to enable this.

1.88 Our approach to financing our plan means:

- Our average prices between 2015 and 2023 will be 16% lower than they have been over DPCR5.
- Some of the benefits of RIIO-ED1 have been accelerated into DPCR5
- Our prices will reduce by a further 18% in 2015

Managing Uncertainty

We have fully addressed uncertainty and risk in our business plan using the principle that risk should be borne by those most capable of managing and mitigating it. This means we seek to manage all risks that we can exercise reasonable control over. Our plan allows for all business as usual risks, such as unit costs and delivery, to rest with us and we reflect this in our Cost of Equity calculation.

1.89 Some things are so uncertain that it is not sensible for us to price the risk into our plan. If we did, it could result in unnecessary price increases being passed on to customers. In these circumstances, Ofgem offers a range of uncertainty mechanisms which seek to protect both the DNO and its customers from significant cost and price risk. These uncertainty mechanisms include reopening specific areas of the price control, flexing cost allowances as volumes change and pass-through of certain costs.

1.90 Our main areas of uncertainty include:

- Load-related investment
- Smart meter implementation
- The Traffic Management Act and other legislation changes
- Real Price Effects
- Nuclear power station at Moorside, Cumbria

1.91 We have established appropriate monitoring and provided flexibility in our plan and delivery model to be able to address them.

Load-related investment

1.92 This will be driven primarily by the adoption of low carbon technology, such as electric vehicles, heat pumps and photovoltaic panels. Our plan assumes that adoption rates will be in line with the Government's 'Low' scenario. If another scenario develops and our plan is out by more than 20%, Ofgem will allow us to reopen this part of the price control.

Smart meters

1.93 Smart meter implementation is driven by the Government's programme which requires their installation in all domestic and small commercial premises by 2020. We have a role in supporting this programme and we also plan to use smart meter data to improve the way we interact with our customers and manage our network.

1.94 Ofgem have provided a pass-through mechanism which allows us to recover our smart meter data and systems costs in full until the implementation programme is complete. Thereafter, we will meet any on-going costs from efficiencies.

1.95 Our plan assumes our technicians will have to provide assistance for 2% of all smart meter installations. If the number increases, Ofgem have proposed a volume-driven adjustment, which we agree with.

1.96 We recognise that smart metering will benefit all parties involved, customers, suppliers and DNOs. In order to ensure that the smart metering implementation programme is carried out efficiently and to ensure the best experience for customers we are supportive of the work being undertaken under the Distribution Connection and Use of System Agreement to develop a service level agreement which sets out distributor and supplier obligations.

Traffic Management Act and other legislation changes

1.97 Under the Traffic Management Act 2004, Highway Authorities can introduce specific restrictions, requirements and charges for the work we need to do on public streets. Different authorities are introducing the Act's provisions at different rates and with different levels of charging. We have dealt with the financial impact so far however it is possible that our costs could increase by around £20 million as the Act is implemented in Greater Manchester.

1.98 We are also aware of a number of potential changes in EU legislation which could have a significant impact on our investment and operating costs. These relate mainly to new restrictions on or specification of the equipment and materials we use.

1.99 RIIO-ED1 has provision for a 'mid-period review' in 2019. At that time, a limited range of issues may be addressed if their impact is material. We propose to deal with any Traffic Management Act and legislative changes at the mid-period review.

Real Price Effects

1.100 Our cost allowances increase by the Retail Price Index (RPI) each year. RPI is based on a broad range of goods and services which represent the average purchasing habits of the population.

1.101 Some of the costs we incur, particularly those related to commodities like copper, steel and oil and some specialist labour costs, can increase at a greater rate than RPI. This difference is referred to as Real Price Effects (RPE). We have included £82.6 million of RPE in our plan but we have fully offset this with efficiency savings in our cost base.

Moorside nuclear power station

1.102 There are plans to build a new nuclear power station at Moorside in Cumbria. National Grid is in discussion with the developer, NuGen, about the arrangements to connect the station to its transmission network. It is possible that the transmission connection would require us to dismantle and remove some of our existing network and install new transformers and switchgear. As we do not know when the connection will go ahead and what the option will be, we propose to use the Strategic Wider Works mechanism available to transmission companies. We think this offers the right level of protection for our customers and us.

Innovation

Innovation is one of our core values and we are leading the industry in developing innovative solutions that challenge and improve the way we do things for our customers and stakeholders.

1.103 We innovate because we want to continue delivering exceptional results for our customers and stakeholders now and in an increasingly unpredictable future. Being able to adapt to changes in demand on our network caused by the uptake in low carbon technology, customers switching from gas to electricity, economic growth and the challenges of fuel poverty is critical to our continued success.

Track record

1.104 Through DPCR5 we have invested £18 million in innovation with an expectation that we will deliver over a £100 million of benefit through cost avoidance and efficiency improvements in RIIO-ED1 and ED2.

1.105 We deliver successful outcomes by aiming innovation at specific stakeholder and customer needs. We manage innovation through a robust governance process that ensures we deliver it in the most practical and cost-effective way and embed it in our day-to-day business.

1.106 We understand the benefits of a collaborative approach. We lead national industry forums, develop best practice which we share with other DNOs and we learn from other organisations as an innovation 'fast follower'.

1.107 We are one of the few DNOs to have successfully maximised use of their DPCR5 innovation funding. The success of this investment contributes substantially to the £140 million of savings which we will deliver by the end of DPCR5.

Our RIIO-ED1 Innovation plan

1.108 Our plan focuses on our stakeholders' priorities of reliability, affordability, sustainability and service and is split into two phases of activity.

- 2015-2019 - We will focus on developing our network's capability to expand and meet anticipated demand increases whilst maintaining an exceptional level of reliability and customer service
- 2019-2023 - Our focus will be the delivery of our data strategy and use of smart meter information to drive efficiency, reliability and capability on our network

1.109 We are requesting a Network Innovation Allowance of 0.8% of allowed revenues. This equates to approximately £24 million of funding for RIIO-ED1.

Key Messages

1.110 Our Well Justified Business Plan is the result of three years' dialogue with our stakeholders and customers. We asked, they answered, we listened and we acted.

1.111 We have developed a plan which offers an exceptional combination of network performance, customer service and value-for-money. It targets our stakeholders' priorities of affordability, reliability and sustainability.

1.112 We are reducing our average prices by 16% compared to DPCR5, delivering the benefits of RIIO-ED1 early by not having to increase our prices for domestic customers in 2014-15 and kick-starting RIIO-ED1 with a price reduction of 18% in 2015-16.

1.113 We are improving network performance through a prudent, innovative and ambitious programme which will reduce Customer Interruptions and Customer Minutes Lost by 20% compared to 2012 levels.

1.114 We are investing to support and enable the transition to a low carbon future and doing everything we can to reduce our own Business Carbon Footprint and losses across our network.

1.115 We are financing all of this with an imaginative proposal which supports our Investment Grade credit rating and is in line with Ofgem's expectations of an efficient financing package.

1.116 We are committing to deliver all of this with a level of customer service excellence which will set a new benchmark for our industry.

1.117 We face a challenging and increasingly unpredictable future but we are confident that our plan prepares us well to face it.

1.118 Our plan was reviewed by Ofgem who found it satisfied four of their five key criteria. This version of the plan includes a further £34 million of expenditure reductions, £76 million less revenue and considerably more detailed information that explains why the investments we are making are the most efficient for the people of the North West.

2 Company Overview

Who we are and what we do

Electricity North West Limited is the electricity distributor for the North West of England. Our job is to provide a safe and reliable supply of electricity, keeping the lights on 24 hours a day, seven days a week for our 2.4 million customers.

2.1 To do this, we own and operate an efficient network which we:

- Maintain – so that our network operates safely and efficiently
- Repair – fix our network when it goes wrong
- Renew – replace and refurbish our network when required
- Reinforce – increase the capacity of our network to meet our customers' changing needs

The electricity industry and the role we play

2.2 The electricity industry in Great Britain is divided into four main sectors:

- The **generation companies** produce electricity from a variety of sources. These can range from coal and gas power stations to wind farms.
- The **transmission companies** own and operate the high voltage network which links the major power stations to the distribution networks and transport electricity in bulk across the country. National Grid Electricity Transmission is responsible for the transmission network in England and Wales.
- The **distribution companies** own and operate the lower voltage electricity networks connecting the high voltage network to every home and business in Great Britain.
- The **electricity supply companies** buy the electricity from the generation companies and sell it to their customers. They pay the Transmission and Distribution Network Operators for the transportation of that electricity across their networks.

2.3 As a monopoly business we, like all the other electricity distributors in Great Britain, are regulated by Ofgem (Office of Gas and Electricity Markets). We operate under an electricity distribution licence which regulates our activities and ensures that we fulfil our obligations and responsibilities fairly for the customers we serve now and in the future.

Ownership and structure

2.4 Electricity North West Limited is a private limited company registered in England and Wales. We are owned by a consortium of funds managed by Colonial First State and JPMorgan Asset Management Infrastructure Investments Group. This consortium purchased the business in 2007 from United Utilities PLC.

2.5 Colonial First State is the asset management division of the Commonwealth Bank of Australia. It manages A$ 150 billion of assets on behalf of institutional clients and pension funds.

2.6 JPMorgan Asset Management is the asset management division of JPMorgan Chase & Co. It manages over US $1.4 trillion of assets on behalf of pension funds, institutions and other clients.

2.7 Both Colonial First State and JPMorgan have a strong track record of experience in UK infrastructure investments. Both place a very high value on ethical and sustainable investment and are committed to the long-term success of Electricity North West.

Our vision and values

2.8 We are driven by a vision to be the leading energy delivery business. To support this, we have developed a set of values which underpin our culture, behaviours and how we interact with all our stakeholders.

2.9 These values support everything we do and influence our activities from strategy development (such as the creation of this RIIO-ED1 business plan) to operational delivery (such as the way in which we talk to our customers). 'Living the Values' and achieving the vision are fundamental to the success of our business. Our customer value is at the heart of everything we do.

Our business

2.10 We are a major employer in the North West of England. We have over 1,600 staff who all contribute to delivering a safe, reliable and efficient service for our customers.

2.11 Our people are our most important asset and our people value helps ensure the sustainability of our business by developing the right mix of skills and resources to meet current and future needs. We have implemented structured development programmes, which allow us to develop and maintain a workforce of motivated, high-performing and capable individuals and attract new people to our organisation. We are making substantial investments in our graduate and apprentice programmes, as part of our £24 million workforce renewal programme. We provide secure, long-term, quality jobs and career development opportunities.

2.12 Our workforce is divided into two areas:

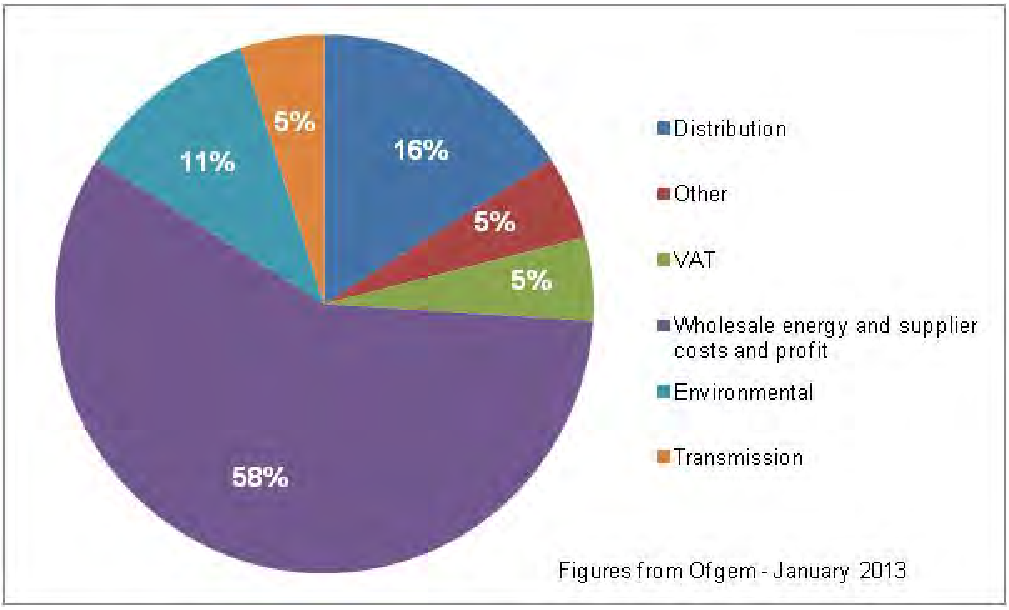
- Delivery, which is focussed on providing an efficient and reliable service for our customers
- Support, which provides essential services such as HR, Finance, Training and Legal

2.13 All our people work very closely together to develop and deliver our ambitions and meet our challenges. Around 80% of our people work in Delivery and 20% in Support.

Our regulatory environment

2.14 Our charges are paid by electricity suppliers who in turn incorporate them into the prices they charge their customers. Our costs account for around 16% of the average domestic electricity bill. Ofgem regulates our charges through the price control framework. We are currently nearing the end of the fifth price control since privatisation (DPCR5), which covers the period from 2010 to 2015.

Components of typical electricity bill



2.15 Above is the breakdown for an average electricity bill. It reflects electricity prices in December 2012. The average electricity bill for a standard account is £531. This price is based on average annual consumption figures, averaged across all the former incumbent suppliers, all payment methods and averaged across Great Britain.

2.16 This regulatory framework will change in 2015, making way for RIIO-ED1, a new eight-year regulatory mechanism. This links our Revenue to the Outputs we deliver and uses Incentives and Innovation to ensure we deliver even better value for customers now and in the future. Stakeholder engagement plays a vital role in this new framework.

2.17 The RIIO-ED1 price review determines how much we are allowed to charge to fund our network investment and operating costs from 2015 to 2023.

Our operating environment

2.18 We are focussed on providing a reliable and efficient service for the people of the North West. We recognise the vital role we play in ensuring the North West continues to be a thriving and vibrant economic hub as well as a great place to live and work.

2.19 Our network is made up of pylons, overhead lines, underground cables and equipment such as switchgear and transformers, which are used to distribute electricity to our customers' homes and businesses.

2.20 Electricity enters our network from the National Grid through 15 Grid Supply Points. Our job is to deliver that electricity through a series of decreasing voltages to our 2.4 million domestic and business customers. Our network delivers over 23 terawatt hours of electricity each year across an area of 12,500 square kilometres.

2.21 We operate across a diverse range of terrain and serve a variety of customers ranging from isolated farms in rural areas to sites of heavy industry and city centres.

2.22 As a rough guide, about 55% of our customers live in Greater Manchester, 30% in Lancashire and 10% in Cumbria, with the remainder in parts of Cheshire, Derbyshire and North Yorkshire.

2.23 Our network comprises:

- Around 13,000 km of overhead lines
- Over 84,000 items of switchgear
- More than 34,000 transformers
- Over 44,000 km of underground cables

Our track record

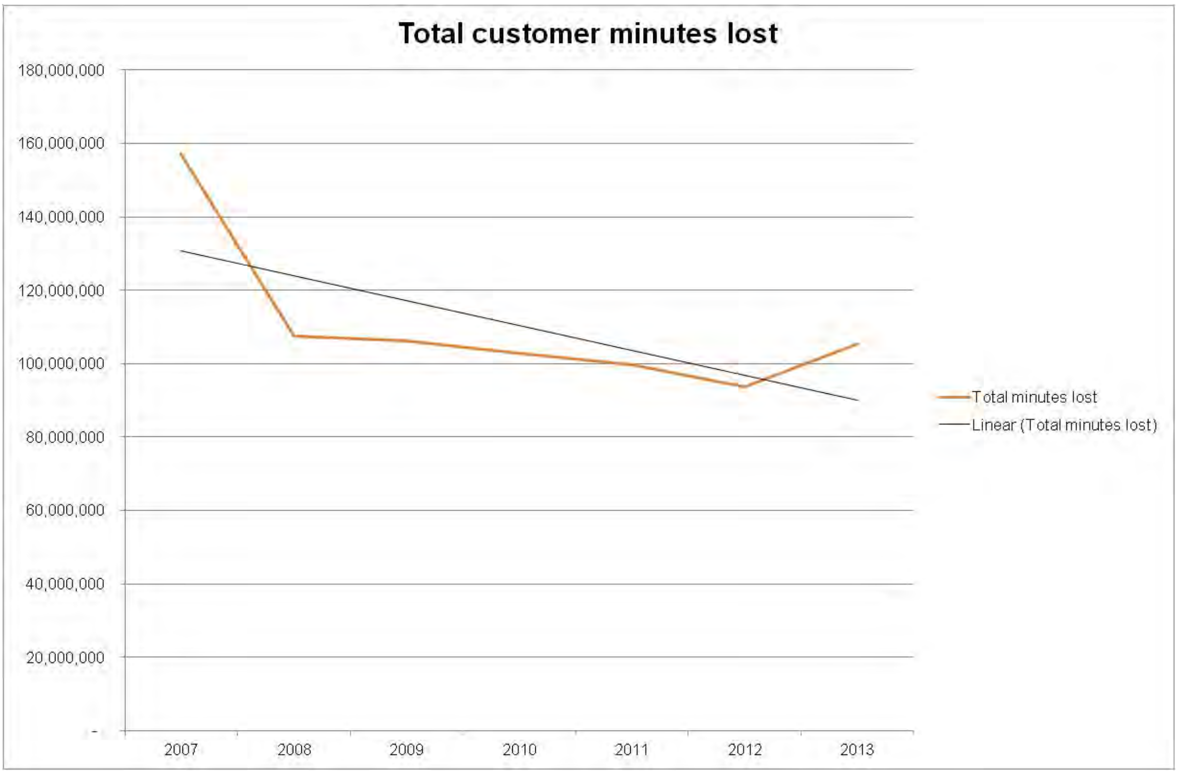
We acquired the business from United Utilities in 2007 and since then we have established a strong track record of service improvement, cost efficiency and industry-leading innovation. This provides us with a sound base from which to achieve our RIIO-ED1 objectives and gives us both the credibility and confidence that we can deliver our commitments.

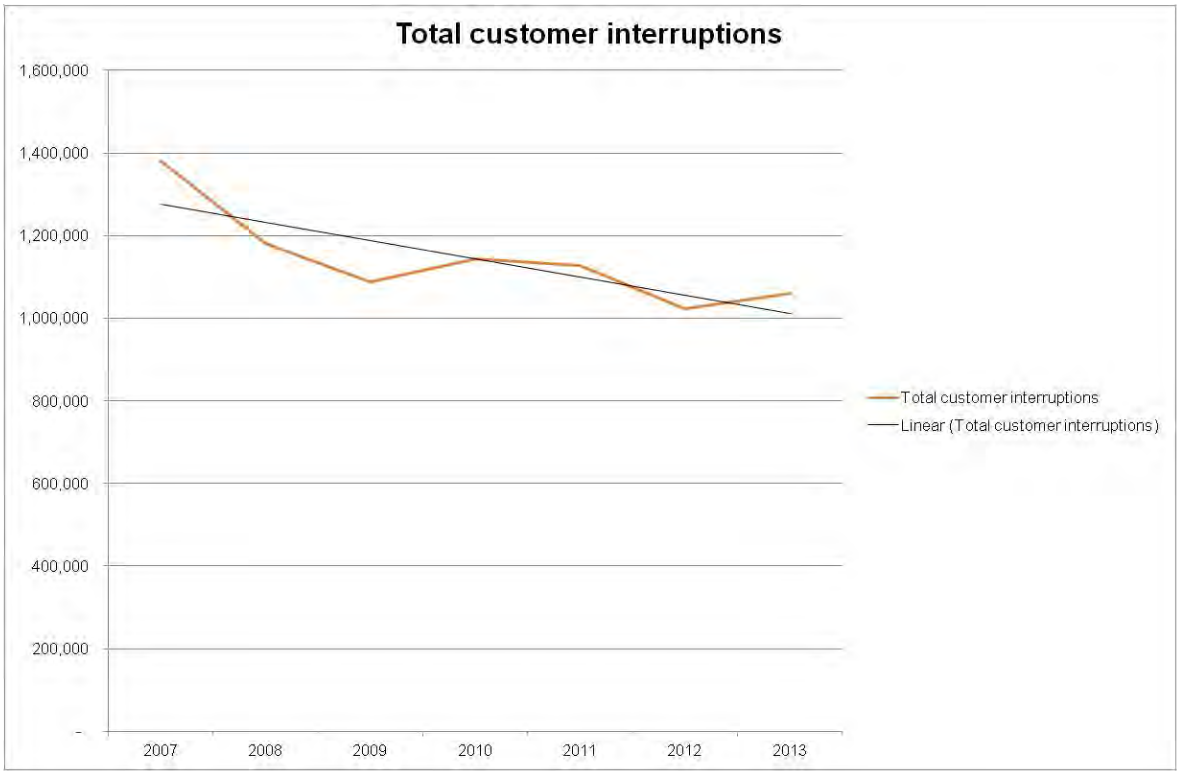
2.24 We are delivering value for our customers by:

- Improving network performance
- Delivering investment programmes
- Investing in customer service
- Enabling the development of a competitive connections market
- Driving down costs
- Innovating to respond to challenges

Improving network performance

2.25 We have improved our network performance through the application of best-in-class asset management practice, better informed refurbishment and replacement decision-making and improved operational response to faults. Since 2007, we have improved Customer Interruptions (CIs) performance by 16% and Customer Minutes Lost (CMLs) performance by 18%, making our network one of the most reliable in the UK.



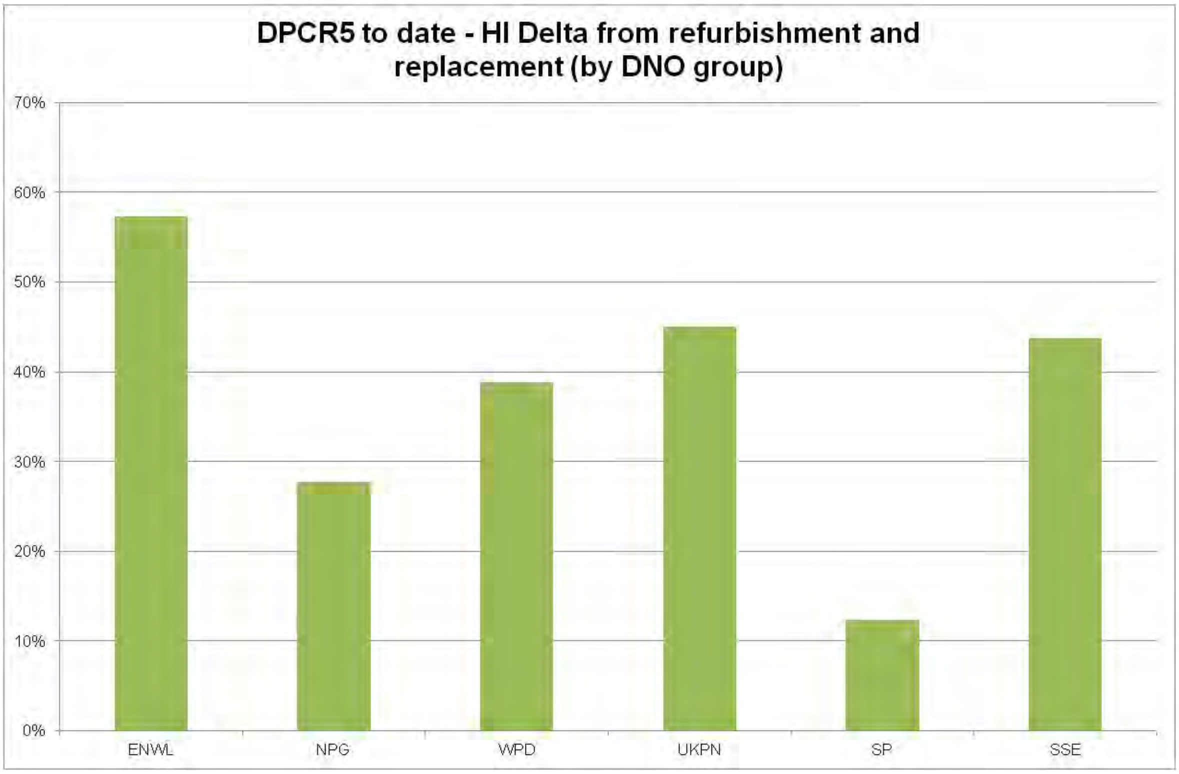


2.26 Whilst this business plan focuses on our performance improvement plans for 2015 to 2023, we will continue to improve network performance through the remainder of this price control in order to ensure our customers continue to receive the excellent service they have grown to expect.

2.27 We have pioneered innovative Condition Based Risk Management (CBRM) techniques for managing our network assets. This methodology allows us to get more from our investment, drive performance improvement and has set an industry benchmark for asset management. We have held BSI PAS-55 asset management certification since 2007.

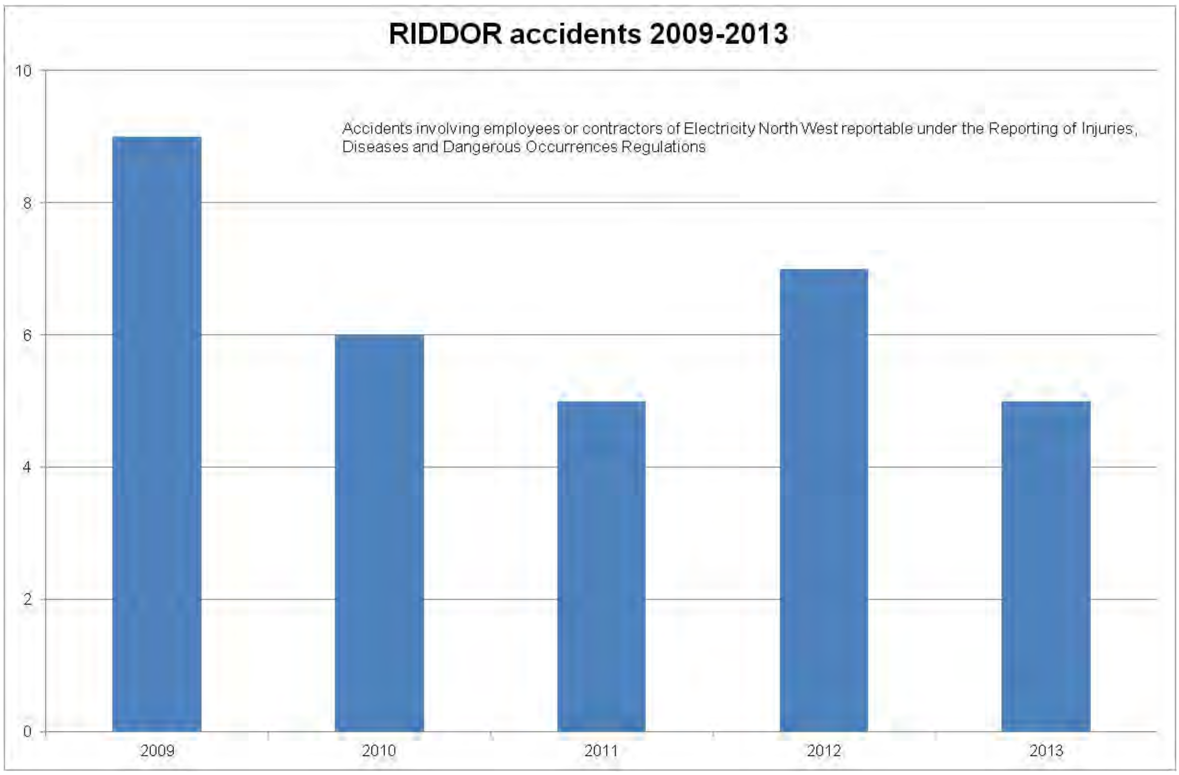
2.28 We measure the condition and loading of the network using indicators called Health Indices (HIs) and Load Indices (LIs). We are on track to deliver the targets set by Ofgem for both these measures for DPCR5.

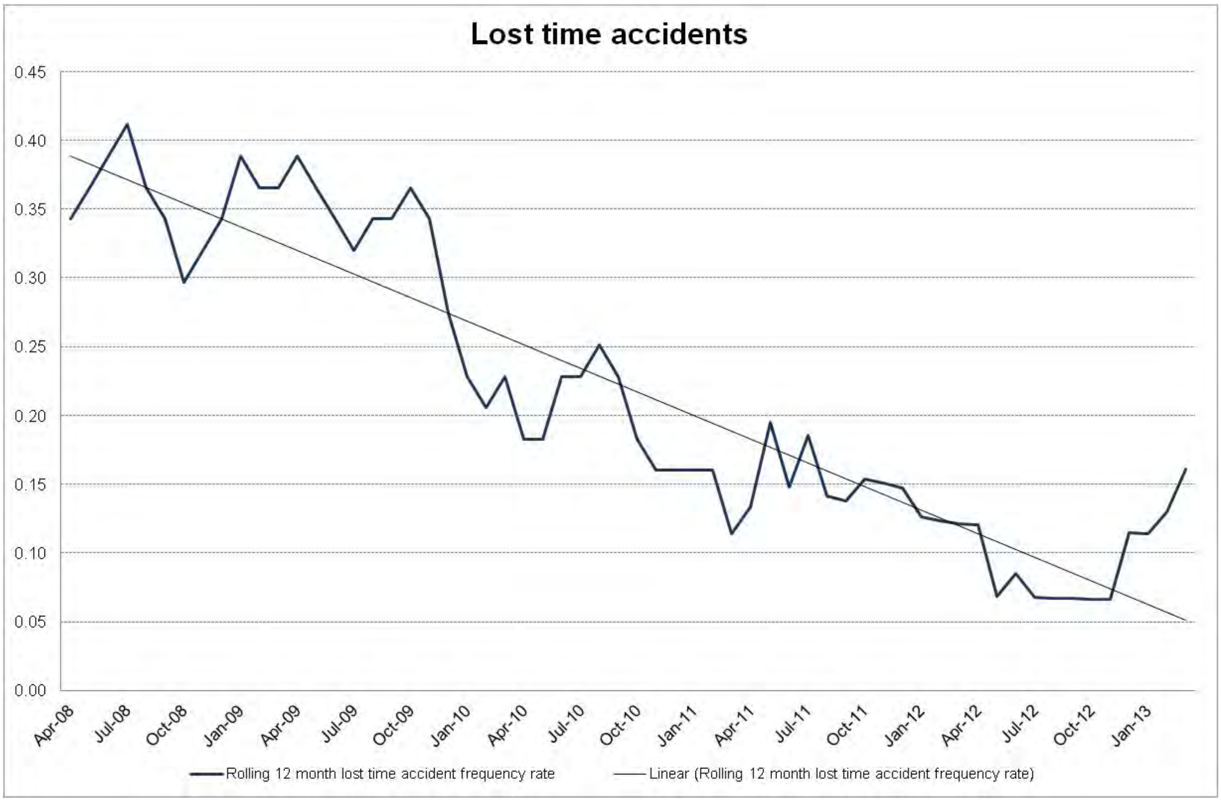
In the first two years of DPCR5, we delivered a higher proportion of our overall DPCR5 HI target than any other DNO group.



2.29 We are committed to achieving the highest standards of safety for all our customers, employees and contractors and operate a 'zero harm' culture underpinned by a health and safety management system certified to OHSAS 18001.

2.30 Accidents involving employees or contractors of Electricity North West, reportable under the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations ('RIDDOR') have decreased significantly since 2009 as have Lost Time Accidents (LTAs).





Delivering investment programmes

2.31 We will invest £1.4 billion in our network between 2010 and 2015 to ensure its continuing reliability, availability and resilience. Our stakeholder engagement continually shows us that customers want us to maintain a stable level of investment to ensure the network can meet their needs now and in the future.

2.32 We have a track record in delivering investment programmes on time and within budget. Many of these programmes have led the industry in terms of delivering customer benefits.

2.33 Since 2007 we have been protecting our network against flooding, ensuring that more than 850,000 customers are no longer at risk from losing supply due to severe flooding of major substations – an area our customers feel particularly strongly about. We completed our DPCR5 flooding programme in 2013-14, a year ahead of the original schedule.

2.34 We have been installing a new fibre communications network to provide our own communications facility and replace the services rented from BT. This is our largest single project in DPCR5 and will complete on time in 2014.

2.35 By the end of 2016, we will be fully compliant with the Electricity Safety, Quality and Continuity Regulations (ESQCR). This programme has run for a number of years and involved checking and where necessary correcting the clearances of our overhead lines to the ground and nearby buildings and structures.

2.36 We have made significant improvements in the security of our substation sites in response to increased break-ins and metal theft incidents. By 2014 we will have improved security at all our major substations and replaced all our locking systems by 2015. We are implementing a number of innovative solutions, such as cable marking, which help deter theft and, when it does happen, assist the police in investigating and securing a conviction. This is already having a positive impact on reducing the number of incidents we experience.

2.37 We have continued to underground overhead lines in National Parks and Areas of Outstanding Natural Beauty in collaboration with our regional partners and stakeholders who represent these areas. This programme has been very successful and continues to deliver tangible improvements in visual amenity.

Investing in customer service

2.38 We have focussed on delivering customer service where our customers want it most – a reliable, efficient network. We recognise that we need to support this with an equivalent standard of customer communication and interaction.

2.39 In early 2012, we created a dedicated customer directorate as the focal point for all our customer interactions. We supported this by investing £1 million of our funds in a flagship Customer Contact Centre.

2.40 We are building on this technical investment by investing in recruiting, training and developing a motivated team of customer service agents.

Enabling the development of a competitive connections market

2.41 We have led the way in opening up the connections market to new entrants. This provides choice and price benefits for our customers and contributes to the economic development of our region.

2.42 The market for new connections is split into nine different segments. Ofgem has so far agreed that we have enabled competition in six of these, the highest number of any DNO We have applied to Ofgem to have the remaining three segments declared competitive and we are confident that all segments will be competitive by the end of 2014. When this happens, we will be the first DNO to have enabled a fully competitive connections market.

Driving down costs

2.43 We constantly challenge our costs and have implemented a range of initiatives to reduce them, including scope and process improvement opportunities.

2.44 As a result we have:

- Reduced bespoke design effort and cost by introducing standard designs and solutions
- Standardised work procedures and materials requirements generating procurement, training and inventory management savings
- Implemented new techniques that allow targeted replacement of individual components, allowing us to reduce costs by working more efficiently and eliminating some consequential work

2.45 We have secured significant savings in materials and labour costs through new procurement and contracting processes.

2.46 We mainly contract with regional suppliers, who operate with a lower cost and overhead base. We develop close commercial, technical and operational ties with these companies to help them understand our needs and requirements and thereby better design the products and services they provide to us.

2.47 We benchmarked ourselves against the competitive asset management market and used this to identify further improvement opportunities. We have reduced the costs of our support functions and our plans include further efficiencies that reduce costs by at least 1% year-on-year.

2.48 We continue to challenge our support cost base by:

- Identifying the core processes and activities needed to support the efficient delivery of work, projects and corporate services
- Eliminating handoffs, duplicated effort or abortive work
- Integrating processes to ensure our organisation operates as an efficient whole, rather the sum of discrete parts

2.49 Our efforts to reduce costs have been successful. As a result, we anticipate sharing around £140 million in DPCR5 cost efficiency savings with our customers. We are continuing this cost reduction commitment in RIIO-ED1, where our delivery costs are expected to be among the lowest in our industry.

Innovating to respond to challenges

2.50 The outlook for our industry and the wider energy industry is already changing. We have to adapt to changes in social, economic and environmental conditions which means we need to find newer, better, cheaper and faster ways of providing our service. One of our biggest challenges is enabling and transitioning to a low carbon future.

2.51 We are responding to this by:

- Enabling the mitigating actions of others, either in terms of changing electricity generation or electricity usage

- Reducing our own carbon footprint
- Adapting our network to withstand the impacts of climate change

2.52 Electricity demand is predicted to increase as we respond to the challenges of decarbonisation of heat, transport and power generation. The technologies which will support this have yet to be widely adopted but we are leading the way in finding efficient ways to cope with their impact.

2.53 Our C_2C (Capacity to Customers) project was awarded funding from Ofgem's Low Carbon Network Fund (LCNF) in December 2011. The project will trial the use of new technology and innovative commercial contracts to increase the amount of energy that can be distributed through our existing network. In April 2013 the first trial customer, Bolton Arena, agreed to a managed contract for an 18-month trial period.

2.54 We are also developing our CLASS (Customer Load Active System Services) project, following an Ofgem funding award of £9 million in November 2012. CLASS runs from January 2013 until September 2015. Like C_2C, CLASS will trial a cutting edge technique to maximise the use of the existing network. While C_2C frees up capacity by reconfiguring the network and using our reserved emergency capacity, the CLASS trial will reduce demand by reducing voltage.

2.55 Our latest LCNF project, Smart Street, will incorporate LV network meshing technologies, active voltage management and conservation voltage reduction. This project will deliver direct cost reductions for customers through reduced energy charges, reduced DUoS charges and higher FiT revenues.

2.56 We have reduced our own carbon footprint by 10% since 2010 and are planning further reductions over the remainder of DPCR5 and throughout RIIO-ED1. This is underpinned by plans to rationalise and improve the efficiency of our property estate and transition to an increasingly efficient fleet of vans, trucks and other vehicles.

2.57 The most significant impact of climate change on our network will be from the increased frequency of extreme weather events, particularly flooding. Between 2010 and 2015 we will install flood protection at 31 major substation sites.

2.58 Innovation is not just about big, technology-driven projects. We look to innovate in the way we run our day-to-day operations through process improvements, organisational considerations and training and developing our people.

2.59 We have developed new and more efficient ways to buy the plant and equipment we need to maintain and improve our network. We have worked with product developers to design new or better components, which mean we can complete work quicker with less disruption to our customers' supplies. We are deploying new communications tools to improve the way we get information from our field staff to our Customer Contact Centre to ensure we give our customers accurate and meaningful information in real time.

2.60 We have introduced proactive payment of Guaranteed Standards of Performance (GSoP) payments to customers on our Priority Services Register and developed new relationships with the British Red Cross to deliver enhanced support to our vulnerable customers. We have introduced online quotations for connections customers and have implemented an online fault map which will be supplemented with an online planned outages schedule in the near future. We are also trialling new ways to provide enhanced notification of planned outages and restoration times to our customers. Our innovation track record is enviable and we are committed to maintaining it.

Our challenges

Our customers and stakeholders believe our number one priority is to keep the lights on. Our plans will deliver on this commitment and respond to the changing and challenging environment in which we have to deliver.

Keeping the lights on

2.61 Our customers will become even more dependent on electricity and consequently less tolerant of power cuts. We need to continually improve our network's reliability to meet their expectations. We have to do this in the context of an ageing network and increasing sensitivity to prices.

2.62 We also have to consider the performance of the network in more extreme circumstances. Recent events such as the Cumbria floods in 2005 and 2007 and severe storms of Christmas 2013, together with the impact of service failures in other companies due to extreme one-off situations, has led to an increased focus on protecting the networks against the effects of rare but potentially significant events.

2.63 We forecast that growth on our network will continue to be largely driven by demand from customers for new connections to new buildings. The rate will be driven by a combination of population and economic growth factors.

2.64 Society does not stand still and we need to plan for changes in the social and economic circumstances in our region.

2.65 Figures from the Office of National Statistics predict that the population of our area will increase by 10% over the next 25 years. Growth will be concentrated in Greater Manchester, which is expected to grow by 12%, with growth of around 7% in the remainder of our area.

2.66 Just over 90% of our customers are domestic, consuming around a third of the electricity used in our area, so we will have to develop our low voltage network to cope with a larger population, living in a higher number of households in urban environments.

The low carbon future

2.67 The UK Government has committed to reducing carbon dioxide (CO_2) emissions by 80% of their 1990 levels by 2050.

2.68 In the energy sector, reductions will be achieved through:

- The introduction of low-carbon generation, much of it locally produced
- Measures to reduce the overall amount of energy used
- More intelligent use of the electricity that is used
- Decarbonisation of heat and transport

2.69 Much of the low carbon generation will be small-scale technologies such as wind turbines, biomass or photovoltaic cells, which will connect directly to our network rather than the transmission network.

2.70 The growing popularity of electric or hybrid cars and heat pumps will create additional demands on our network.

2.71 Decarbonisation of heat and transport has the potential to create significant increases in total energy distributed and in the peak demand for electricity, the timing of which will not necessarily coincide with local generation.

2.72 The UK's electricity transmission and distribution networks have been designed on the basis that electricity flows in one direction, down through the voltage levels. Local generation will introduce significant levels of flow up the network so the way that the network is designed and managed will need to change from a passive one-way system to one where we actively manage the flows of power. This actively managed system is often referred to as a smart grid. Whilst the total smart grid vision may be some way off, the introduction of smart meters across the UK by 2020 will help us start the transition.

New technology

2.73 We expect the introduction of new technology to accelerate over the next 40 years and this creates uncertainty in our long-term plans. New consumer products may be popularised in the same way that mobile phones and other digital devices have, placing greater demand on our network. Conversely new technologies may be introduced which will make appliances (particularly white goods) co-operate with distribution networks to reduce demand and help manage peak loads.

2.74 In the transport sector, the major initiative to reduce CO_2 emissions will be the introduction of electric vehicles. The Department of Energy and Climate Change's (DECC) pathways projections present a scenario where vehicles become more efficient and there are breakthroughs in battery technology. This will drive the introduction of significant numbers of electric and plug-in hybrid electric vehicles, so that by 2050, 60% of mileage will be covered by these vehicles. This will present a major challenge to electricity networks.

2.75 It is estimated that the electricity required to travel 80 miles is equivalent to the daily consumption of an average house. We will need to increase the capacity of our network to cope with the added demand from electric vehicles, whilst ensuring that the management of the refuelling electrical load is undertaken in a smart manner.

2.76 As we look to the future we expect that the majority of our network infrastructure will appear largely the same as it does today. New technology will help us to manage it more effectively through greater use of real-time data, remote operation and smart solutions.

Our response – the way forward

We are proud of our track record and believe we are well placed to achieve our vision of being the leading energy delivery business.

2.77 Our plans for the future build on these strengths and will deliver a more reliable, affordable and sustainable network for our customers. We need to support this with first-class service so we are committed to delivering industry-leading performance in the way we communicate, interact and inform our customers about our activities. We want to ensure that every point of contact with customers delivers a consistent and excellent experience.

2.78 We are also focused on ensuring our plans are driven by the needs and requirements of our stakeholders now and in the future. Our stakeholder engagement process is robust and embedded in our business and we will maintain this engagement throughout DPCR5, RIIO-ED1 and beyond.

2.79 We have used the Ofgem Outputs framework to enable the discussion on our priorities with stakeholders and to articulate our proposals and ideas for the future.

2.80 The framework comprises six Outputs:

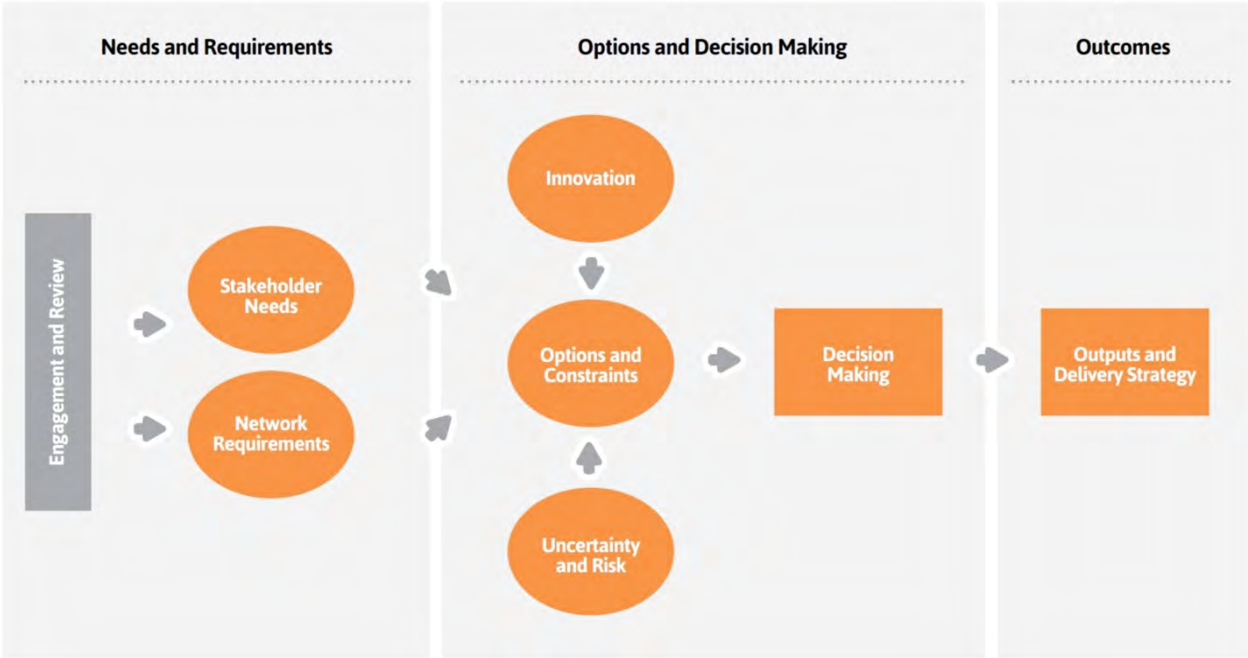
- Safety
- Social obligations
- Reliability and availability
- Customer satisfaction
- Connections
- Environmental impacts

2.81 For each, we constructed a range of costed options that we presented to customers and stakeholders to identify their priorities and willingness-to-pay (or not) for improvements. From this, we have constructed an overall plan which balances the needs of our network with stakeholder priorities and affordability.

3 Process

In this section we describe the process we have followed to establish our RIIO-ED1 plan, which is illustrated in the diagram below.

The process for creating our Well Justified Business Plan consists of three stages.



We engage with our stakeholders through our 'Switched On: North West' campaign. This helps us to understand their needs and expectations of our network and service.

3.1 We used demand forecasting tools and asset performance projections to understand how we need our network to perform in order to meet the capacity and reliability requirements placed upon it over the long term.

3.2 We assessed a number of options and constraints in order to optimise the plan. We followed some guiding principles for determining our Outputs and used decision-making tools to help decide the best approach when a trade-off between stakeholder priorities occurred.

3.3 We also considered how new technologies and innovative solutions will challenge our ways of working and provide new and alternative options for delivering our plan. The outcome from this process is a set of clear, measurable outputs aligned to our stakeholder priorities supported by a strategy to deliver them.

Bringing our business together

3.4 Our people work together to deliver a reliable and efficient service for our customers. We carried that ethos into our business planning process, involving every part of our company in its development. We created a development plan, which integrated all our different skills, disciplines and organisations and a governance process, which provided robust feedback, challenge and approval of every aspect of the plan.

3.5 Our approach was simple. Let our experts develop their plans for their specific areas and then bring them together to refine the parts into a cohesive whole.

3.6 None of our teams work in isolation but each team has specific talents, skills and objectives. We believed it was right to ask them to develop their initial ideas to provide the opening framework for our plan. We coordinated this through a Business Plan Steering Group.

3.7 We coordinated our asset management, engineering planning, innovation and operational teams through a Network Delivery Steering Group, which allowed us to develop a cohesive investment and intervention plan that we were confident we could deliver.

3.8 We created a Finance Steering Group, which combined our Finance and Regulation teams to develop an efficient and compliant forecast, cost efficiency benchmarking and our financeability strategy.

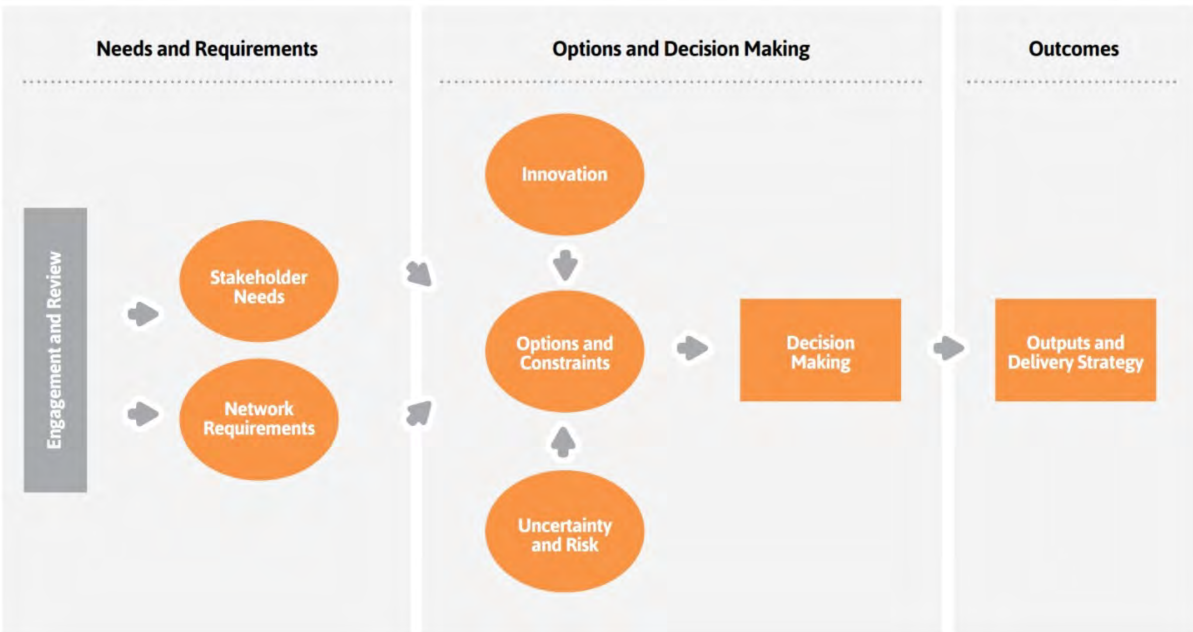
3.9 The wider plan was co-ordinated by our RIIO Steering Group, chaired by our CEO and comprising senior representatives from each part of our business. The Steering Group set and directed the overall strategy for our plan.

3.10 Our Executive Leadership Team (ELT), which comprises the Directors from each part of our business and is chaired by our CEO, was responsible for deciding final strategy and direction based upon recommendations from the RIIO Steering Group.

3.11 Finally, overall approval of the business plan rested with our Board.

WJBP business engagement

Expertise from across the business has been used throughout the process of formulating, developing and finalising our Business Plan for 2015-2023. The process diagram below highlights how and where business engagement fitted into the development of the original submission.



Business Engagement	Business Engagement	Business Engagement
Title: RIIO Working Groups: Stakeholder engagement; Analysis; **Dates**: December 2011 - May 2013 **Frequency:** Monthly **Attendance:** All business directorates were represented	**Title**: Investor Workshops **Dates**: 2012-2013 **Frequency**: Quarterly **Attendance**: Investor Groups and ELT. Directors and CEO	**Title:** NewsWire magazine **Dates**: May/July 2013 **Frequency:** Monthly **Attendance**: All employees
Title: Interactive ELT Roadshows **Dates:** 2012 **Frequency:** Twice yearly **Attendance**: All employees	**Title:** Board Meetings **Dates**: Ongoing **Frequency**: Quarterly **Attendance**: All Directors	**Title:** Strategic Direction Statement Briefings **Dates**: May/July 2013 **Frequency**: one off **Attendance**: All employees
Title: NewsWire Magazine Dates: 2011 onwards Frequency: Bi-monthly Attendance: All employees	**Title:** RIIO Steering Group **Dates**: June 2011 – ongoing **Frequency:** Fortnightly **Attendance**: Regulation Director and team; Finance Director and team; Network Strategy team: Head of Communications and stakeholder team; Procurement team	**Title:** Summary Business Plan **Dates:** July 2013 **Frequency**: one off **Attendance:** All employees

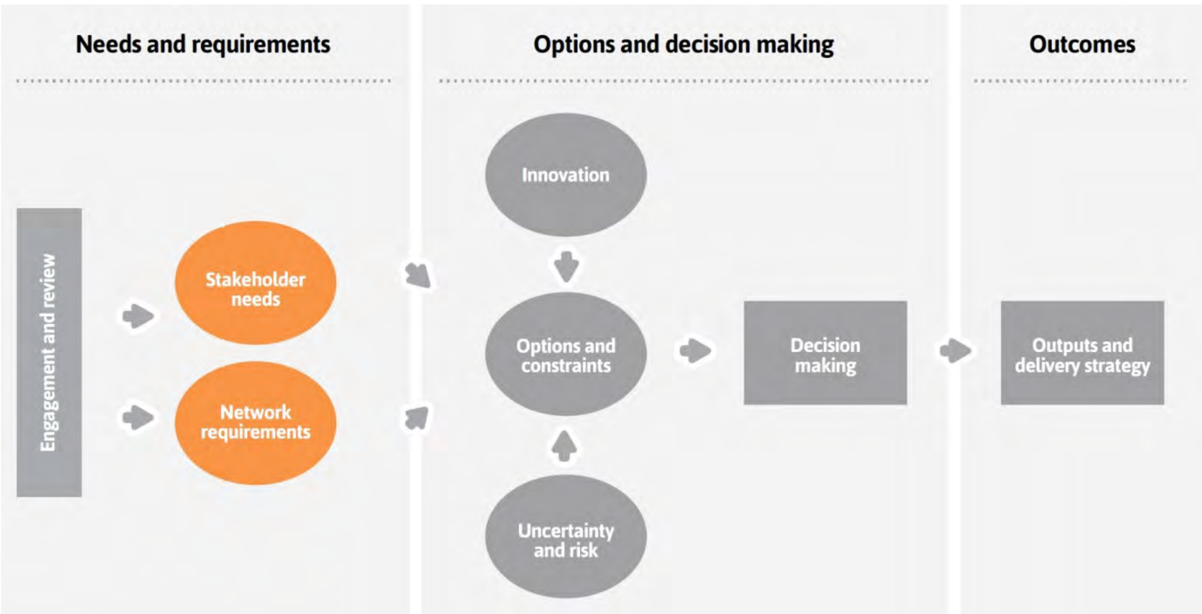
Business Engagement	Business Engagement	Business Engagement
Title: Apprentice and Graduate Workshop Briefings **Dates**: 2012 onwards **Frequency**: Annually **Attendance:** Apprentices, graduates, and trainees	**Title**: ELT RIIO Meeting **Dates**: December 2011 May 2013 **Frequency:** Monthly **Attendance:** All ELT Directors and CEO	**Title:** ELT Road shows **Dates**: July 2013 **Frequency:** Bimonthly **Attendance:** All employees
Title: RIIO Module in Management Development Programme **Dates**: 2012 onwards **Frequency:** Quarterly **Attendance**: All developing managers	**Title**: RIIO Working Groups: Work Programme and Volumes; Unit Costs; Delivery Methodology; Financing **Dates:** December 2011 - May 2013 **Frequency:** Monthly **Attendance**: All business directorates were represented	**Title:** Summary document on employee intranet (The Volt) **Dates:** July 2013 **Frequency**: ongoing **Attendance:** All employees

Needs and requirements

Engagement and review

3.12 Our business plan is developed around the needs of our stakeholders. We have engaged in extensive consultation to understand their expectations of the services we deliver.

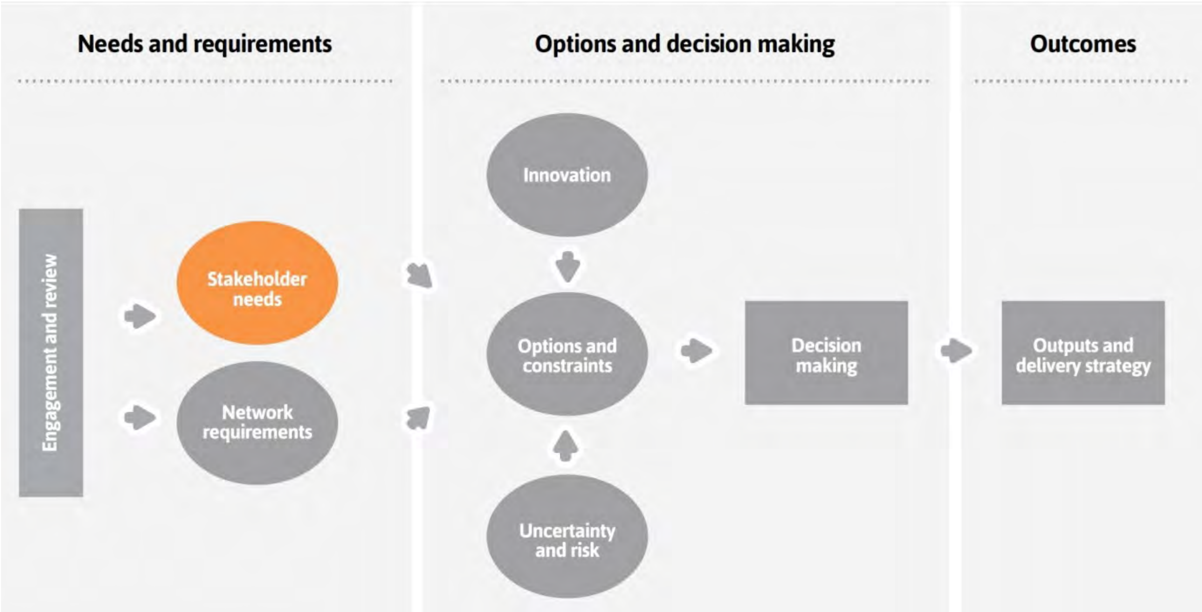
3.13 We need to remember that our network has been around for a long time and the maintenance and performance requirements of our existing poles, lines, transformers and other assets dictate a substantial part of our RIIO-ED1 plan.



Stakeholders' needs

3.14 We serve 2.4 million customers throughout the region; however, what we do affects more than 5 million people throughout the North West.

3.15 Our engagement approach (see Annex 1) has been to ensure that we listen to all our stakeholders' views to enable us to identify their key priorities for our plan.



3.16 Our stakeholders want:

- Reliability in our network
- Affordability in the services we deliver
- Sustainability for the environment and communities we impact
- Customer Service excellence

3.17 These priorities are not always complementary to one another. Clearly explaining where we can (and in some cases cannot) meet their needs is a very important part of our stakeholder process.

Identifying our stakeholders

3.18 Our description of our 2012-13 stakeholder engagement programme for the reporting year ended 31 March 2013 has been independently assured by Deloitte LLP in accordance with the International Standard on Assurance Engagement 3000 (ISAE 3000 – a standard that has been designed by the International Auditing And Standards Board (IAASB) to assure non-financial data).

3.19 Our approach is detailed in Sub-annex A1: Stakeholder engagement strategy (from entry to Ofgem's 2013 Stakeholder Engagement incentive scheme) of Annex 1: Stakeholder methodology and responses. In this we describe how we have developed our stakeholder engagement programme applying the three principles of the AccountAbility AA1000 Principles Standard, inclusivity, materiality and responsiveness.

3.20 We serve a diverse population whose needs and priorities differ. We used a robust methodology to identify our different stakeholder groups and to analyse the level of influence they have on our plan. As a result, we developed a structured stakeholder grouping, influence and engagement model.

Engaging with our stakeholders

3.21 Our engagement process has been running for many years. We learned from our early experiences that we needed a way to efficiently co-ordinate and filter views, communications and feedback. In 2012 we launched our 'Switched On: North West' campaign to complement our business-as-usual engagement and focus on RIIO-ED1.

3.22 A key part of the campaign was the 'Switched On: North West' website, and much of our engagement activity directed stakeholders to this hub. The website was structured around some key areas:

‘Why act now?’

3.23 This section was used to educate and inform stakeholders about the future challenges we face. We created a range of short films to explain them and requested stakeholders to give their views and opinions. We recognised that clear communication in this area was essential if we were to get meaningful and valuable feedback. We also recognised the importance of engaging with school children and young people as they will be the bill payers and opinion formers of the future.

‘Have your say’

3.24 This section gave stakeholders the opportunity to complete an on-line survey. We developed a range of surveys, which were tailored to individual stakeholder groups to ensure they were as meaningful as possible. These on-line surveys ran alongside our external activities such as the school, shopping centre and railway station roadshows.

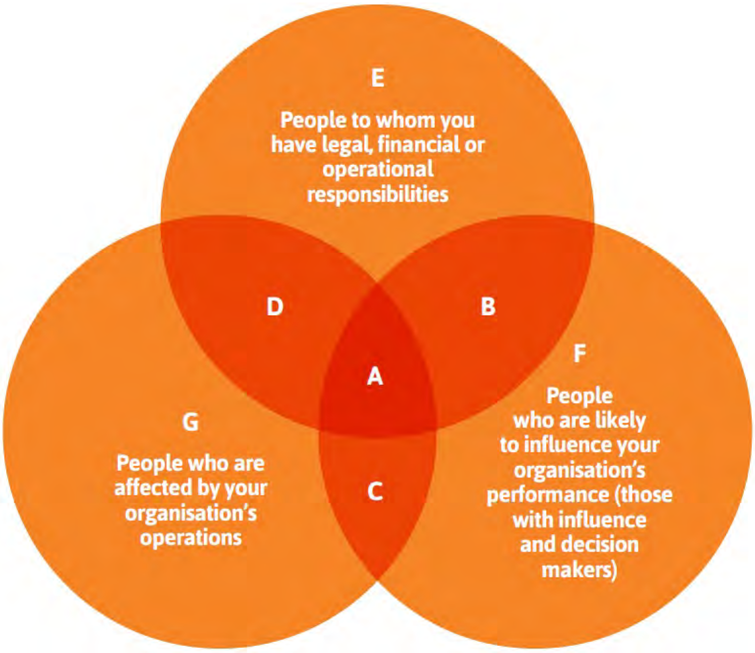
‘Your influence so far’

3.25 This section captured and collated stakeholder views and fed back how we had interpreted them. We published “What our stakeholders say” in July 2012 and our “Strategic Direction Statement” in March 2013 to provide formal feedback on how their views were influencing our plan. These publications also asked for further feedback confirming that our interpretation and plan proposals were consistent with their opinions.

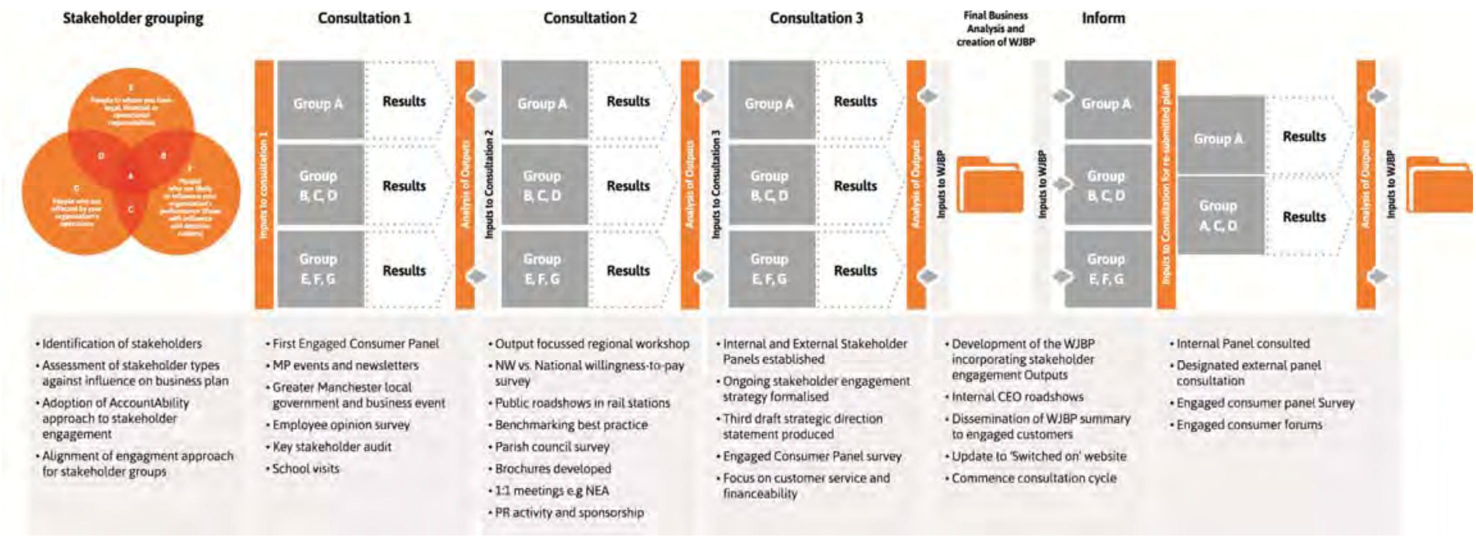
3.26 Through this campaign we conducted the following:

- 7305 North West customers surveyed for membership of Engaged Consumer Panel
- 2272 members of the Engaged Consumer Panel surveyed
- 2059 nationally representative customers surveyed
- 430 face-to-face interviews at five public roadshows
- 102 key stakeholders engaged at six regional workshops
- 27 MPs attended events, 21 MPs returned surveys
- 108 Parish Councils engaged
- Internal and external stakeholder panels established

3.27 Our approach to stakeholder engagement uses an internationally-recognised best practice developed by AccountAbility. This approach follows a robust and comprehensive engagement process and applies defined principles.



Group	Stakeholder	Group	Stakeholder
A	Domestic customers	D	Other regional utilities
	Business customers		Construction developers
	Industrial/major users		Small scale generation developers
	Local authorities/highways		Emergency services
	National Grid		Network Rail
	Network operators		Other suppliers (minor)
	Large scale generation operators	E	Industry code panels
	Landowners		UK Revenue Protection Agency
	Employees	F	Local, regional, national and trade media
	Investors		Credit rating agencies
	Suppliers (electricity)		National Energy Action
	Major suppliers (eg major contractors)		Consumer Futures
	Independent Connections Providers		Carbon Trust
B	National Government		Major Energy Users Association
	Ombudsman		Energy UK (suppliers)
	Energy Networks Association (ENA)	G	Schools
	British Red Cross		Environmental charities
	Business in the Community		Web users
C	Lobby groups		Social media users



3.28 Stakeholder engagement is fully embedded in our day-to-day business and we are committed to continuing it now, through RIIO-ED1 and in the long term.

3.29 We developed and refined our stakeholder strategy by working with:

- Weber Shandwick who supported us with stakeholder identification and initial engagement
- Populus who undertook market research to understand what people think about our business
- 3G communications who helped with detailed stakeholder engagement and feedback
- AccountAbility who provided advice on standards, governance, approach and assurance

Engaged Consumer Panel

3.30 Stakeholder engagement informed us that only a third of adults in our region had heard of Electricity North West and only about one in eight adults knew what we do.

3.31 We worked with Populus to develop a process to educate specific groups of customers about our role within the electricity industry and the challenges that we face. We were then able to ask these engaged customers questions relating to our operations and plans, to which they were able to express informed responses.

3.32 We have used engaged customers' views, behaviours and attitudes as the best possible representation of the views that all customers would hold if they knew more about us.

3.33 In addition to the formal engaged panels, we have made questions from the panels available to all of our stakeholders on our engagement website: www.enwl.co.uk/switchedon.

3.34 Our willingness-to-pay questionnaire was developed to create an online survey that allowed stakeholders to modify their own 'bill' based on a range of costed options covering all Output categories.

3.35 This powerful tool, adapted for use on our 'Switched On: North West' website, enabled a wide range of stakeholders to participate and express their views.

Cycle 1

- stakeholder identification
- key output and materiality determination
- first Engaged Consumer Panel
- Greater Manchester local government and business event
- launch of first Strategic Direction Statement (2011)
- qualitative key stakeholder audit
- engaged consumer questionnaire
- MP events and newsletters
- employee opinion survey
- Executive Leadership Team internal roadshows
- 'Switched On: North West' branding and minisite launched (www.enwl.co.uk/switchedon)
- social media launch
- school visits
- online willingness-to-pay survey
- educational videos produced
- first public roadshows

Cycle 2

- Engaged Consumer Panel willingness-to-pay survey
- second strategic direction statement produced
- sponsorship of key publications
- increased PR activity and awareness raising
- further videos produced
- 'How stakeholders are influencing our business plans' brochure produced
- 1-1 meetings with key new stakeholders including National Energy Action

- output-focused regional workshops
- 'What our stakeholders say' brochure produced
- further public roadshows in key rail stations
- new process for highlighting types of work carried out with new 'communications for project managers' document rolled out
- **Parish council survey**
- benchmarking engagement against other similar companies to identify best practice

Cycle 3

- **External Stakeholder Panel established**
- ongoing stakeholder engagement strategy formalised
- Internal Stakeholder Panel established
- third strategic direction statement produced
- **industry-wide suppliers' engagement**
- further Engaged Consumer Panel survey focused on customer service and financeability
- Independent Connection Providers workshop

Cycle 4

- **Engaged Consumer Panel Survey**
- Engaged Consumer Panel forums
- **Internal Stakeholder panel**
- External Stakeholder panel
- **Specific project endorsement**

Reporting and feedback

3.36 We looked at all our engagement outputs, identified how our plan needed to accommodate them and communicated our proposals back to stakeholders.

3.37 We produced a number of reports to communicate to our stakeholders how we are responding to their requirements.

3.38 The three most significant are:

- What our stakeholders say (2012)
- How our stakeholders are influencing our business plans (2012)
- Strategic direction statement (2013)

Our stakeholder priorities

3.39 Our stakeholders have told us that we should prioritise our business plan around three themes:

- Reliability
- Affordability
- Sustainability

3.40 They also want us to deliver exceptional Customer Service. We have created a stakeholder priorities framework to guide the development of our plans and focus on setting measurable outputs for these priorities, at the heart of which is a dedication to delivering customer service excellence. This framework is referenced throughout our plan.

Reliability

3.41 This is the level of performance delivered by the network. It is measured in terms of the frequency and duration over which a customer's electricity supply is disrupted.

3.42 Our stakeholders require us to:

- Focus on providing a constant safe supply of electricity – keeping the lights on and responding quickly when they go out
- Improve our 99.99% reliability score whilst managing the trade-off with affordability
- Continue investing in network reinforcement and capacity increases to encourage future economic growth in the region

> *"A proactive approach to potential problems is preferable to a reactive approach. Facilities should be robust and safe from damage from weather or crime."*
>
> *Quote by: Cllr Liz Gaskell, Askam and Ireleth Parish Council, Cumbria*

Affordability

3.43 This is the price customers pay for our service. We will provide an affordable, value-for-money service for all the people in the communities we serve. Our stakeholders require us to:

- Invest in supporting vulnerable groups through the provision of priority services. For many stakeholders their willingness-to-pay increased where the additional cost would be used to fund initiatives for vulnerable customers

- Help address the issue of fuel poverty in the region

- Provide extra support for electricity-only households

Sustainability

3.44 This is the provision of our services in the long term. Our stakeholders require us to:

- Manage our network in a way which balances current and future services and investment

- Help individuals and businesses save energy and reduce their carbon footprint

- Provide a network that will facilitate the connection of low carbon technology such as electric cars and heat pumps

- Respond to issues of climate change, through effective management of the network, use of renewable generation, smart meters and smart grids

Customer Service

3.45 This is meeting our customers' expectations when they interact with us. Our stakeholders require us to:

- Give accurate and timely information whenever they contact us

- Be an easy organisation to do business with

- Manage our connection costs down and offer flexibility in commercial arrangements and types of service

Discounting suggestions

3.46 In some cases we have listened to stakeholder suggestions, but after due consideration we have chosen not to implement them or alternatively have deferred implementation to a later date. The reasons for not progressing with a suggestion were explained to the stakeholders and were primarily due to issues of affordability, technical capability or practicality. Examples include:

"We should target achieving 100% reliability on our network"

3.47 Whilst our network is very reliable we know that the cost to achieve 100% network reliability would be prohibitive. Our aim to improve our customer interruptions and customer minutes lost scores by a further 20% will improve our reliability to frontier levels without passing on unacceptable costs to our customers. Stakeholder suggestion:

"Customers should be charged different amounts depending on the number of faults they have experienced"

3.48 Given that compensation is currently available through Guaranteed Standards of Performance it would not be appropriate to start charging customers differing amounts. Instead, we are investing to reduce the number of worst served customers. Stakeholder suggestion:

"We should provide generators for all our vulnerable customers"

3.49 Around 10% of our customers are "vulnerable" and providing this entire group with generators would be unaffordable. Our focus on improving reliability and restoration times will reduce the number and duration of supply interruptions for all our customers. We are working with the British Red Cross to deliver enhanced support to our vulnerable customers when they most need it. Stakeholder suggestion:

"We should underground all our cables"

3.50 The ability to underground all our cables is constrained by affordability and geographical limitations. We have collaborated extensively with stakeholders in rural areas and in particular, National Parks and Areas of Outstanding Natural Beauty, to identify how best to target our investment in undergrounding. We are more engaged than any other DNO in undergrounding cables.

Additional stakeholder engagement for resubmission of Business Plan

3.51 Following the submission of our plan to Ofgem in July 2013 and the subsequent feedback we received, our plans have been reviewed and resubmitted.

3.52 There were three aspects of our resubmission that we sought further stakeholder input on, to ensure that we are making the right decisions for stakeholders.

- Changes to our original submission
- New proposals
- Further formal input and support of original plans

3.53 Using channels we established during engagement for the original submission we were able to go straight to engaged and informed stakeholders for input on the resubmission.

3.54 We held an extraordinary External Stakeholder Panel meeting in January 2014 and also held an extra Engaged Consumer Panel survey and workshop.

3.55 These engagement activities focused on four key aspects of our plan that we felt needed further input from stakeholders, and details in the plan. They were:

- Connections
- Vulnerable customers
- Storm compensation
- Electricity theft

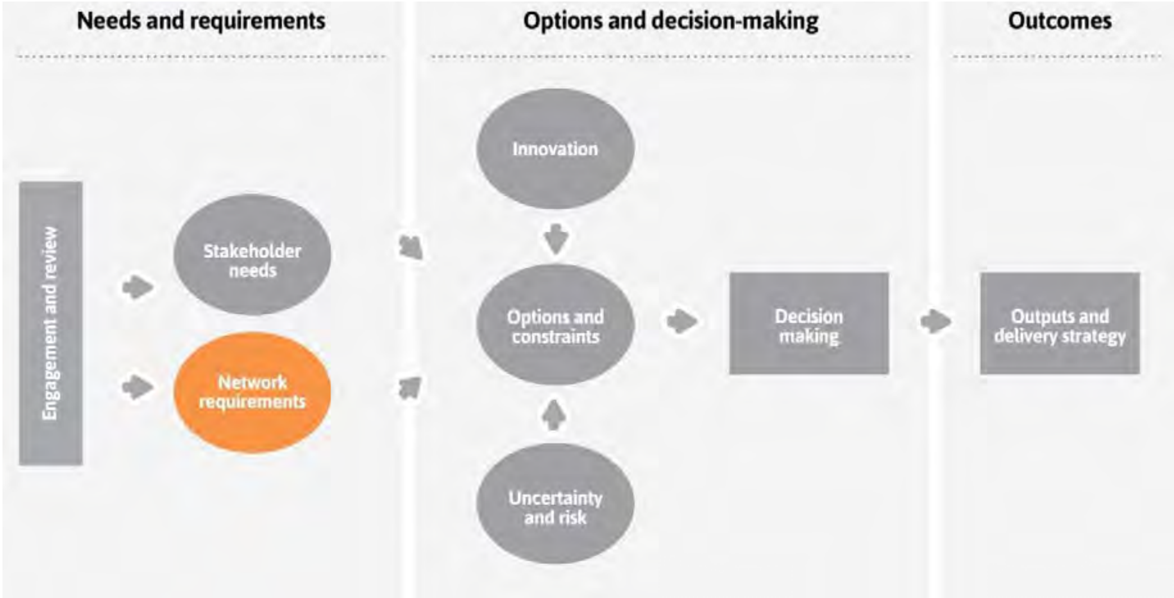
3.56 For further information on stakeholder feedback and how this has influenced our plans, see Appendix 1: Stakeholder Methodology and Responses.

Network requirements

Delivering electricity to everyone in the North West requires significant infrastructure, much of which lasts for decades.

3.57 Our network is a complex system of poles, wires, pylons, switches, transformers and an IT and telecoms infrastructure which helps us operate and control it. We have to balance our decisions to replace, repair or refurbish parts of the network with our stakeholders' requirements for reliable, affordable and sustainable service. Understanding the condition, capacity and capability of our entire network is essential in doing this.

3.58 We also have to comply with all applicable health and safety standards and legal requirements. Safety is our number one priority, and we must ensure the safety of our employees and the general public in everything we do.



Asset Management approach

3.59 We have an obligation to exercise proper stewardship of the assets that we own, ensuring that they remain safe and operable now and well into the future. We use best practice asset management processes to do this.

3.60 We identify the appropriate type of intervention and the right time to do it. We could spend more on assets early in their lives and this would increase reliability but would cost our customers more. Investing less and replacing assets only when they fail may save money in the short term but would result in an unreliable network and higher costs in the long term. We balance the competing factors of reliability and affordability using whole life costs and a risk-based approach to identify the optimum time to replace, renew, refurbish or retire our assets.

3.61 Our asset management practices have achieved BSI PAS-55:2008 certification and are continuously benchmarked against other DNOs and asset intensive industries.

Asset Information

3.62 We gather and analyse information on the condition of our assets. We routinely capture detailed data including the type, location, environmental conditions, age and operational attributes in addition to a condition assessment. This is captured from on-site inspections or automatically from control systems and is then collated and updated in our asset registers. We conduct regular sample audits to check data accuracy.

3.63 We monitor the loading of the high voltage network to identify growth in demand at local 'hotspots' around the system. This helps us determine whether our network can sustain current and future demand or whether further investment in network capacity is required.

Condition Based Risk Management

3.64 We have developed an industry-leading process of Condition Based Risk Management (CBRM) as part of our asset management practices.

3.65 CBRM combines engineering knowledge, practical experience and asset condition information to help us predict future asset performance and risk of failure. CBRM has been widely adopted by other DNOs (see Annex 2).

3.66 Our CBRM process produces for each asset:

- A Health Index (HI); this measures the current condition of our assets and provides an indication of their residual life and probability of failure
- A prediction of how these performance measures will change over time so that we can proactively plan the correct interventions

3.67 We have enhanced our CBRM systems to include an assessment of the consequence of failure of any specific asset. This assessment uses the same parameters as our Cost Benefit Analysis (CBA) (see Annex 3) modelling so that decisions are consistent and based on long-term value for money.

3.68 CBRM outputs are used by our asset managers who are experienced in identifying assets at risk and intervention options (eg special maintenance programmes or replacement of a group of assets). The options are modelled and assessed to determine the optimum balance between value, performance and long-term network health. These outputs are then incorporated within a comprehensive integrated asset management plan that details the best course of action for our network over time.

Demand forecasting

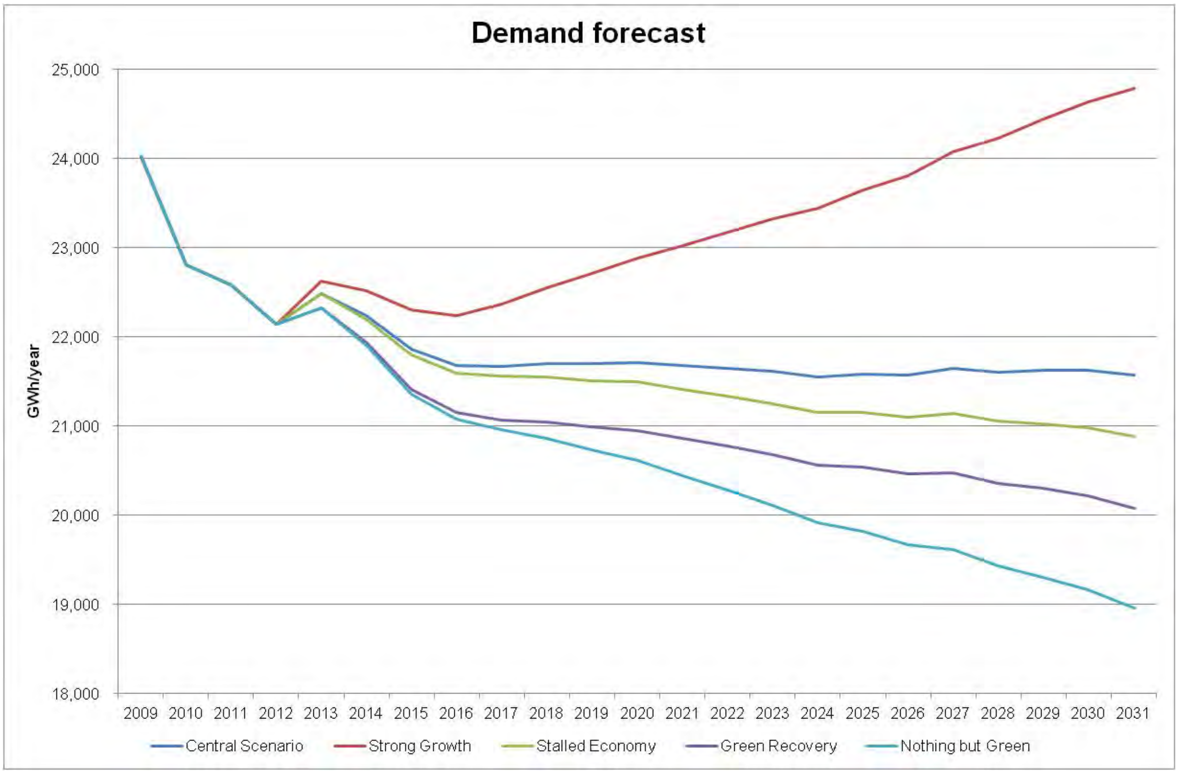
3.69 We have considered how future economic growth in our region may affect network requirements over time. We have worked with Cambridge Economic Policy Associates (CEPA) since 2010 to develop a robust demand forecasting methodology to understand and manage these changes (see Annex 4).

The output of our electricity demand forecasts study is shown below. We see falling demand in the green scenarios, while in the stalled economy and central case scenarios demand is flat through to 2030. Only in the strong growth scenario do we see constantly rising demand, although it does not return to 2008 levels until well into the 2020s.

		Economic Growth		
		Low	**Central**	**High**
Energy Efficiency	**High**	**Nothing but green**		**Green recovery**
	Central	**Stalled economy**	**Central case**	
	Low			**Strong growth**

3.70 We believe the central case is the most likely scenario. This is based upon an expectation that the non-domestic sector will show low levels of economic growth and there will be limited increases in household incomes.

3.71 The other scenarios around the central case have helped us to plan for the likely uncertainties that may impact our plan, particularly the demand for connections and impact of low carbon technologies (LCT).

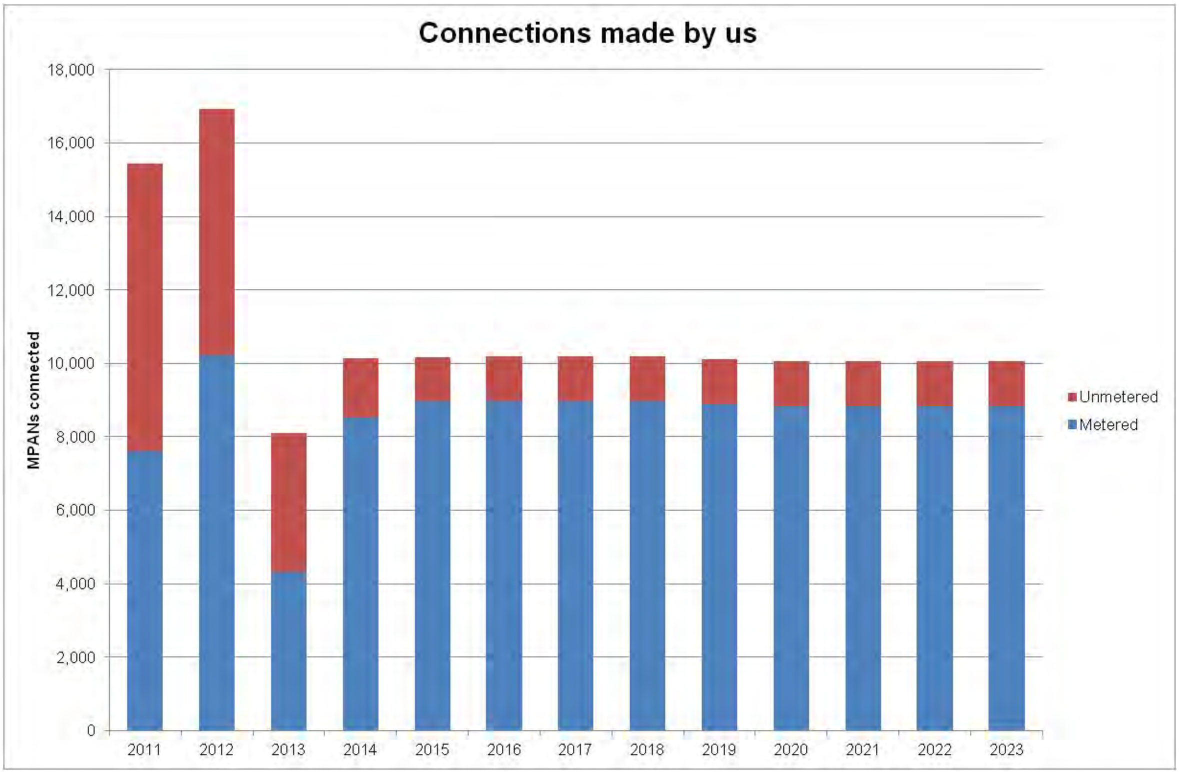


3.72 The pace of transition to the low carbon economy will affect electricity demand growth during RIIO-ED1. The Department of Energy and Climate Change (DECC) has set out four strategic planning scenarios that lead to the delivery of the UK's long-term emissions reduction targets. These are:

DECC scenario	Heat pump	Electric vehicle	Demand side response take-up
Low (4)	Low	Low	None
Medium (1)	High	Medium	None
Medium (2)	High	Medium	Medium
High (3a)	High	High	None

3.73 Government incentives, such as the Domestic Renewable Heat Incentive, will stimulate some demand for LCT, however, the pace of adoption is uncertain. We have concluded that the DECC Low scenario is a prudent and realistic assumption for our business plan. This is based on our assessment of economic growth projections and uncertainty over future Government stimulus measures. We recognise that the future can change and our plan includes specific provisions to deal with these changes.

3.74 The number of new connections made by us, Independent Connections Providers (ICPs) and Independent Distribution Network Operators (IDNOs) will further affect demand on our network. Recent high levels of unmetered connections will tail off as a number of large PFI contracts come to a close and we expect a relatively flat demand for connections throughout RIIO-ED1.



Options and decision-making

Our decision-making process has two interactive stages. From our range of stakeholder requirements we firstly decide what we are going to deliver over the RIIO-ED1 period.

3.75 These are our Outputs. Secondly we decide how we are going to deliver these Outputs, these are our interventions. Deciding what our Outputs should be means balancing sometimes conflicting stakeholder priorities, such as affordability and reliability. We follow a set of guiding principles when determining our outputs:

- We are primarily driven by what our stakeholders have told us they want. There is a continuing requirement for the service we provide using the assets we maintain – the needs of the network therefore determine a large proportion of what we do
- We seek the best long-term value for customers. This is not necessarily the lowest cost option in the short term, or lowest overall cost if there are additional benefits from doing something else (eg carbon reductions from low-loss equipment)
- We continuously benchmark ourselves against our industry and other sectors to make sure we are delivering efficiently (see Annex 5)

3.76 Our stakeholders generally understood and supported our need to take the right combination of decisions and trade-offs to deliver their priorities. We found that;

- There is no significant trade-off between customer service and the other priority areas. Excellent customer service is our stakeholders' minimum expectation.

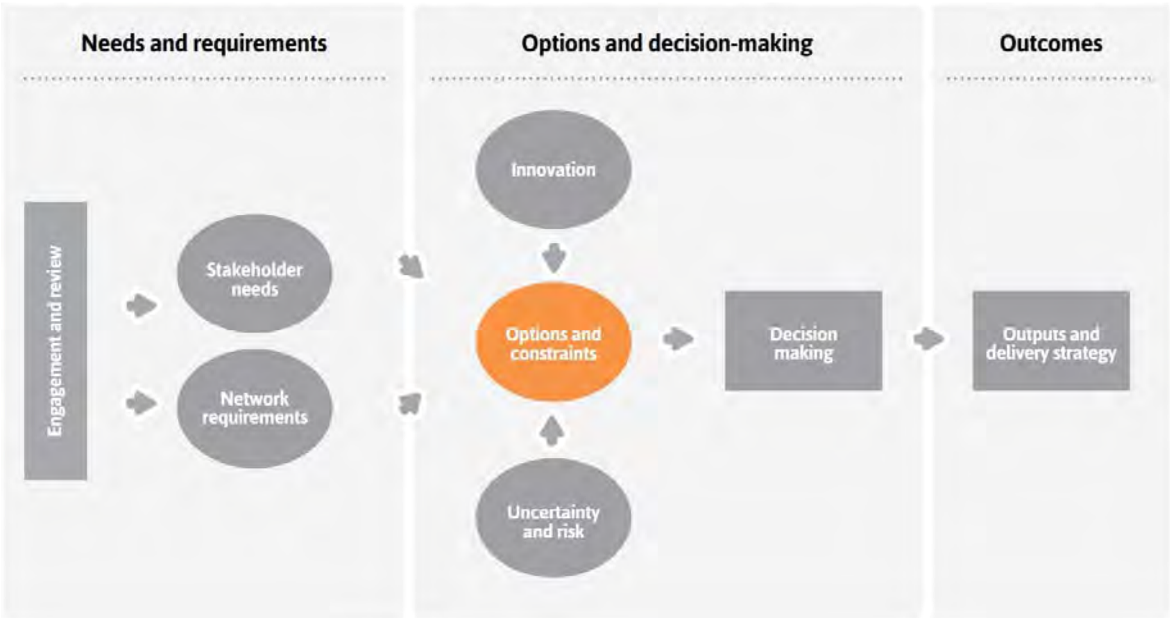
- Our network is extremely reliable; however, we are committed to making it even more reliable through RIIO-ED1. We know that many of our stakeholders want 100% reliability but the cost is prohibitive and would be unacceptable if passed on to our customers. Our business plan will deliver an exceptional level of reliability without burdening current and future customers with disproportionate costs

- Securing a safe, reliable network capable of supporting the connection of low carbon technology and growing demand requires significant investment in reinforcement. As the pace of uptake of these new solutions is uncertain, we have to balance the risk of overspending on reinforcement that may not be required with the risk of spending too little now and reinforcing our network at a greater cost in the future. Our stakeholders have told us that they support the move to a low carbon future however they are not willing to underwrite an unlimited cost. Our business plan is based upon a steady, affordable migration to low carbon solutions

- Trade-offs between reliability and sustainability are limited as in most cases the investments made to facilitate the connection of low carbon technologies to our network will increase reliability

Options and constraints

3.77 Having established our stakeholder priorities and the needs of the network we then develop our plan based upon what will be possible to deliver without unreasonable cost being passed to the customer.



3.78 The decisions we make apply mainly to the selection of interventions on our network assets. These interventions include replacement, renewal, refurbishment or retirement. We consider the following options when developing our intervention plan:

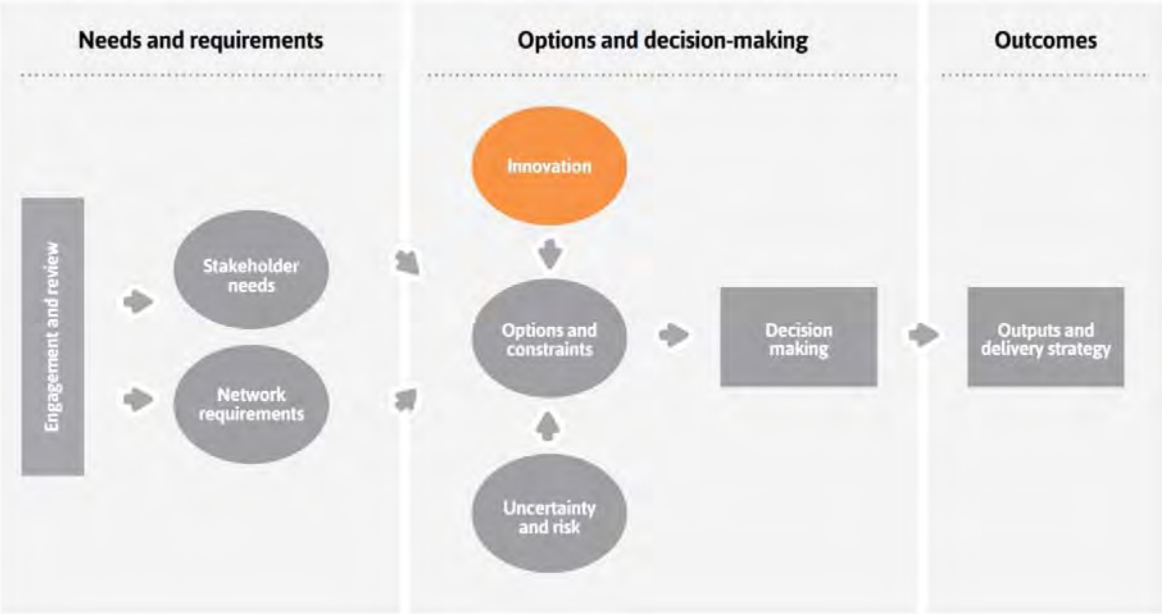
- Do nothing

- Do more or less

- Do different

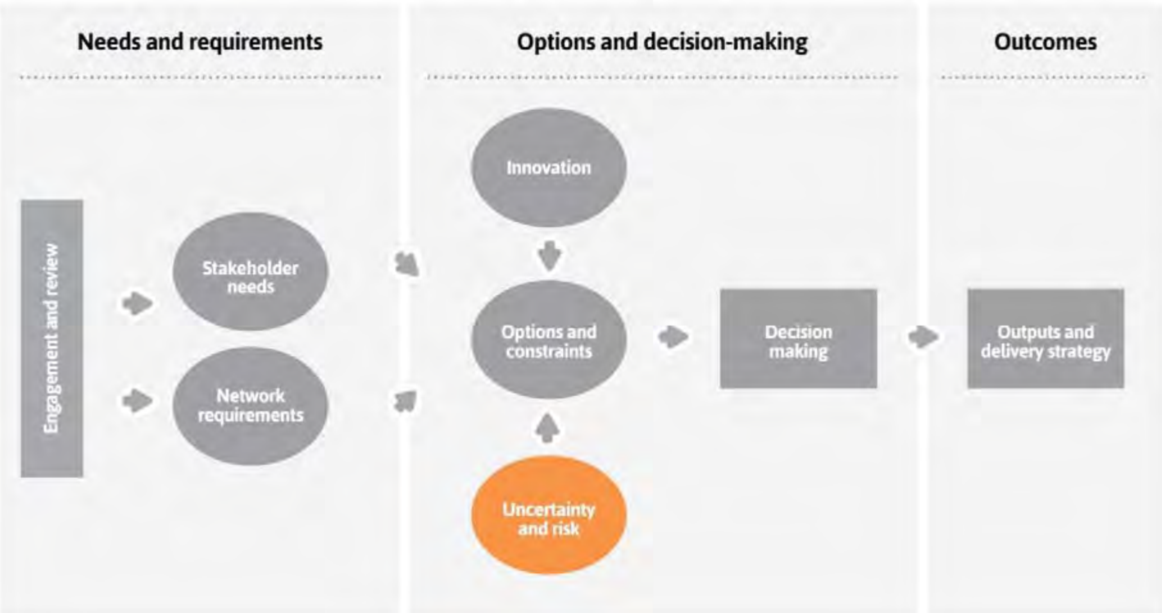
Innovation

3.79 We look to innovation to help us deliver a better service at a lower cost. We follow a governance process to manage the identification, assessment, quantification and implementation of innovative solutions; both our own good ideas and those we see being used elsewhere. Our process ensures that we maximise the benefit of innovation funding from Ofgem and develop projects which will have tangible results in improving cost and service efficiency.



Uncertainty and risk

3.80 We assess the impact of future uncertainty to help inform our decision-making.

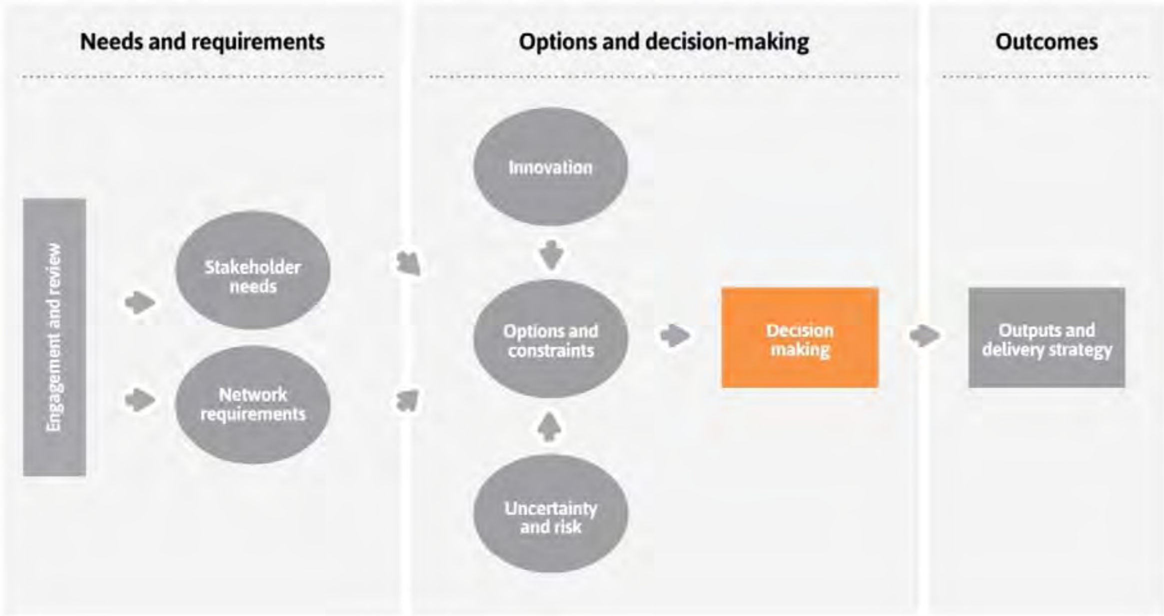


3.81 We consider uncertainty relating to various economic, social, technological and environmental factors and we take these into account when selecting our preferred options. We use our extensive network of academic and industry partners and Government and regulatory relationships to help develop the best possible information about the future and build flexibility into our plan and budget to accommodate deviations.

3.82 We also carry out risk assessments when deciding between alternative intervention options. We evaluate the impact of each option in terms of the risk to network performance and the future costs associated with managing it. This may lead us to choose an option that is not the cheapest but which may be justified if it keeps overall network risk within reasonable limits.

Decision-making

3.83 We make investment decisions based upon a holistic view of the outcome for our stakeholders and the network.

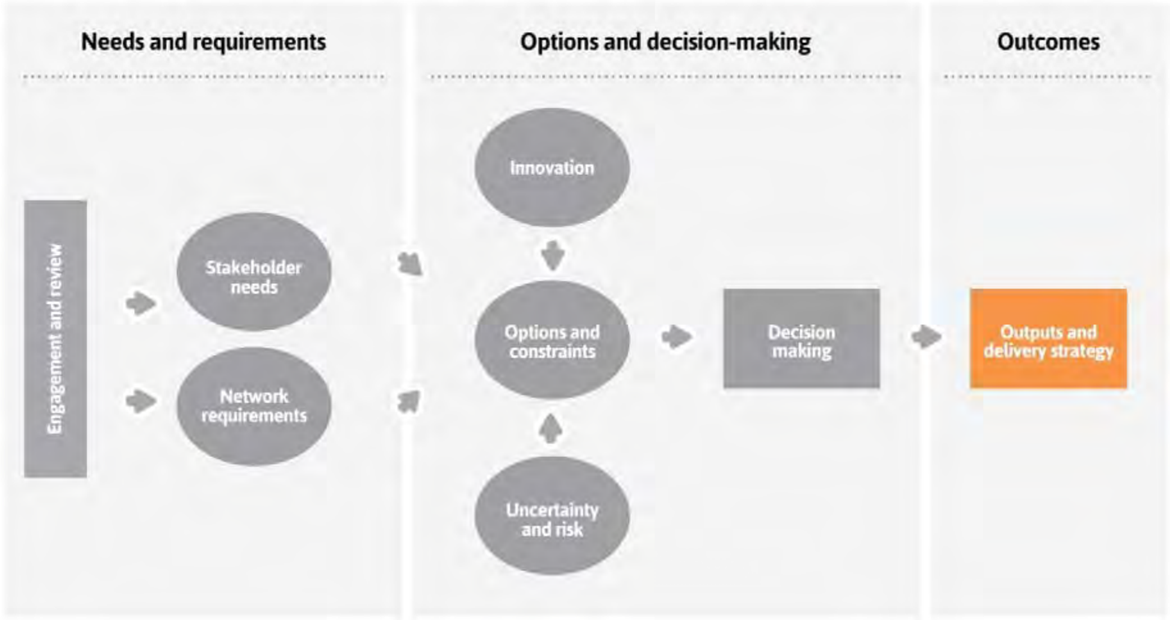


3.84 We use CBA to compare options based on their impact on benefits over the long term and to identify the best value option. We have used CBA predominantly in the following areas:

- To check our asset replacement proposals against increased or reduced options
- To test refurbishment and replacement options against each other
- To test the benefits of additional network capacity or capability

3.85 We apply our CBA methodology above to a defined expenditure threshold. For options that fall below this threshold we apply our established engineering standards and practices to determine the appropriate solution. We have defined a common set of financial and non-financial factors to ensure consistency across our CBA assessments (see Annex 3). These include:

- Direct costs incurred
- Safety
- Environment
- Customer Service



Outcomes

3.86 The outcomes from this section are reflected in Section 4 (Outputs) and Section 5 (Expenditure).

Our delivery model

3.87 Our Direct Labour Organisation (DLO) focuses on delivering our core service of managing and maintaining the network and we use our contracted partners to deliver project work such as civil construction. We do this to ensure that we retain the right base of skills and experience in our core business and give ourselves flexibility to deal with less predictable or more discreet projects.

3.88 We use framework contractors for the delivery of basic works such as excavation and cable laying, overhead lines and plant installation. These contracts have been established through formal market testing to allow for an element of flexibility to deliver additional or a different mix of work if required.

3.89 For major projects we appoint contracted project managers, following a competitive tender process. This allows us to increase or decrease resources according to specific project requirements.

3.90 Our supply chain specialists negotiate competitive agreements by market testing with plant, materials and equipment providers. We also seek out, encourage and reward supplier innovation. As standard practice we place two contracts for all key plant elements ensuring we have an alternative supplier should the principal supplier encounter delivery issues. This allows volumes to be flexed upwards should quantity needs increase beyond a supplier's capacity and reduces frequency of customer interruptions (see Annex 6).

3.91 This delivery model gives us flexibility in terms of capability and capacity. It allows us to effectively utilise our delivery teams to cope with demand variations that are out of our control such as weather events, economic changes, Government policy decisions and changes in the construction environment (see Annex 7).

3.92 We have tested all four DECC scenarios (see Annex 8) to understand the cost and resource implications and explored a variety of procurement options should these changes occur. From our models we are confident that we could cover the additional spend and resource variations associated with changing scenarios with no detriment to any other area of our programme.

Workforce renewal

3.93 We receive a specific workforce renewal (WFR) allowance to recruit, train and upskill new and existing staff in order to replace the 40% or so of our craft, engineering and technical workforce who are eligible to retire within the next 15 years.

3.94 We have invested in a new training academy in Blackburn to provide the capability and capacity to in-source many of the technical and personal skills courses currently delivered by external providers. Enhanced training methods will allow us to reduce training programme length but deliver the same high quality at a reduced cost. This will reduce average annual training costs by £1 million during RIIO-ED1.

Managing risk

3.95 We operate an assured risk management system to manage and mitigate any risks that may impact upon the successful delivery of the business plan. The risk management system has been externally validated during 2012 as being in accordance with ISO 31000 Risk Management - principles and guidelines by SGS UK Ltd.

3.96 Our risk management system includes a policy statement and a risk management strategy to support continual improvement. We have clearly defined roles and responsibilities to ensure effective ownership and delivery of risk management, and all operational and non-operational risks are managed on a single corporate risk register. The corporate register is underpinned by local risk registers in various areas of the business. Risks on the corporate register are designated to a member of the Executive Leadership Team, who has overall responsibility for managing that risk.

Factor	Base Case	Alternative	Mitigation
Electricity demand	Modest economic growth through RIIO-ED1	Economically-driven demand increases would require additional reinforcement and connections activity. Lower growth than forecast would have no material impact on our plan	Continued demand forecasting with CEPA, incorporating national economic scenarios and moderating for the specific conditions in the North West. Sufficient flexibility in operational delivery plan
Low carbon technologies	DECC Low	DECC Medium most likely variant. DECC High unlikely in the absence of significant incentives or breakthrough technologies	Sufficient flexibility in operational delivery plan to accommodate DECC Medium scenario
Smart meters	Implementation complete by 2020. Cut-out replacement rate of 2%	Delayed implementation, however not beyond the end of RIIO-ED1. Cut-out rate could range from 2% to 7%	Continued participation in Smart Grid Forum and other industry bodies. Continued liaison with electricity suppliers to understand plans and timing
Cumbria nuclear power station	Construction will commence during RIIO-ED1	Construction significantly delayed	Financial implications subject to Ofgem Uncertainty Mechanism. No detrimental impact on business plan

4 Outputs

Introduction

The O in RIIO stands for Outputs. Very simply, Outputs are the products and services we will deliver for customers and stakeholders.

4.1 Outputs cover the whole range of impacts that we have as a network operator and are specified in the following areas:

- Safety
- Social obligations
- Reliability and availability
- Customer satisfaction
- Connections
- Environmental impact

4.2 In this section, we set out our range of measures and targets which we are committing to deliver in RIIO-ED1. These have been informed and shaped by stakeholder feedback and our need to meet all the obligations on us as a business.

4.3 Some of these are related to clear service measures (eg power cuts or customer satisfaction), whereas others are designed to ensure overall network risk management, the prevention of unwanted events or some form of secondary effect. In these areas (eg flood protection, undergrounding), the measure is based on the activity we plan to undertake to achieve the ultimate (but difficult to measure) benefit (eg improvement in visual amenity).

4.4 Our Outputs are the leading measures we will use in managing our business and demonstrating successful delivery. We believe transparency of our performance targets is fundamental to our on-going, productive engagement with customers and stakeholders. In particular it will help us ensure we have appropriate support for areas where the future is not yet certain, such as balancing our response to the pace of transition to the low carbon economy and the impact this could have on future customer prices.

4.5 The following sections detail our proposals and describe why we believe they offer the right balance between the needs of the network, our customers and our stakeholders. In developing our Outputs, we have taken account of the benefits offered by data and technology advances and the opportunities they provide to improve our understanding of network performance and customer interaction. We believe an integrated approach to network and customer data will allow us to offer enhanced, and in some cases tailored, services. We have therefore included a brief summary of our data strategy to provide some context of the enabling investment in technology, people and processes which underpins our Outputs programme.

Data strategy

RIIO-ED1 brings a number of social, technical and economic challenges to our industry.

4.6 To meet them, we need to understand what information is going to be available to us, how to integrate it and how to use it to deliver outstanding performance and value for all our customers and stakeholders.

4.7 Our network data and the systems which process it are comprehensive. We have industry-leading asset performance and condition data which allows us to develop and deliver efficient investment and repair programmes. We have extensive automated monitoring and control technology applied across our high voltage network which allows us to identify and fix, or minimise the impact of, faults very quickly. This condition and performance data is supported by control and location systems which allow us to deliver network reliability performance in excess of 99.99%.

4.8 We have a number of sources of customer data which, although helpful, do not yet offer us the functionality to understand and engage with our customers as fully as we would like. We want to understand and perform for our customers as well as we do our network. This means making the most of the information currently available to us and looking forward to how that will be enhanced by future developments, both in our company and across our industry as a whole.

4.9 The introduction of smart meters, which will be rolled out from the beginning of 2015, will help us bridge a major gap in our customer information. In the longer term (towards the end of RIIO-ED1 and throughout RIIO-ED2) we see significant potential to improve customer service through enhancing:

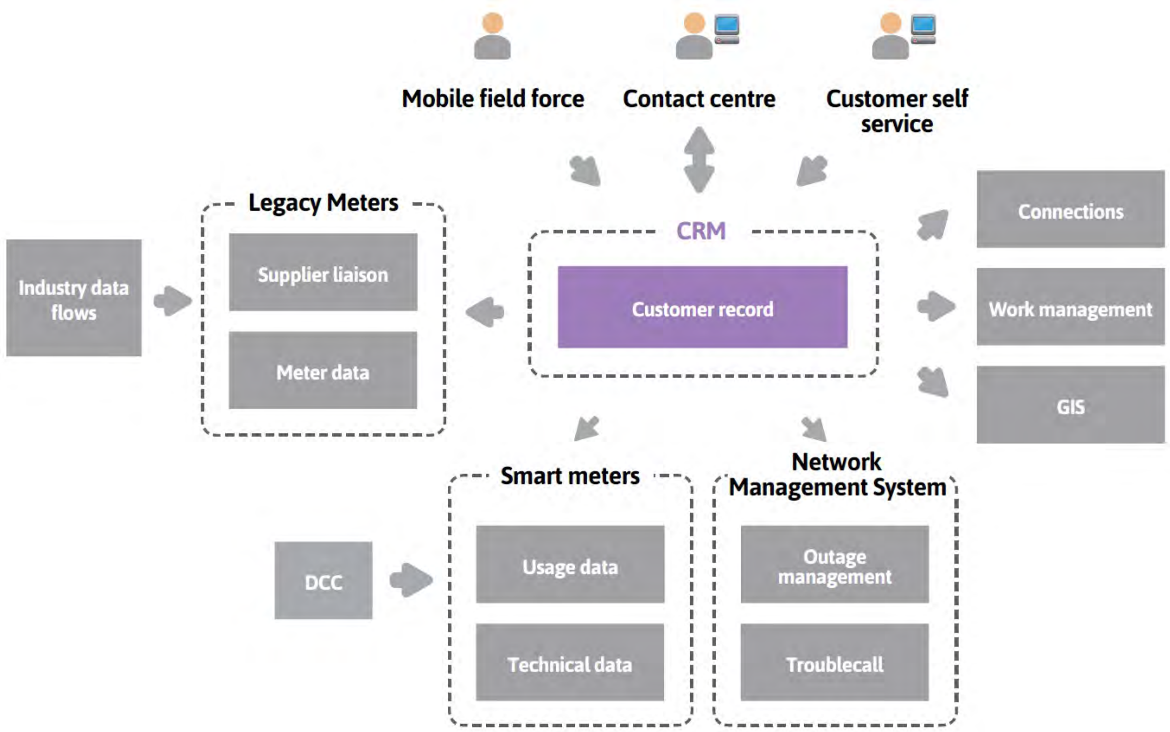
- Customer communication and interaction
- Connections
- Network performance monitoring
- Demand side response
- Management of power outages
- Losses

4.10 Smart meter data on its own is only part of the answer. It will certainly help us better understand our customers' relationships with our network but we need to do more to understand our customers' wider relationships with our business.

4.11 In November 2012, we launched our flagship Customer Contact Centre, the result of a £1 million investment by us. As part of our continued commitment to put customers at the heart of our business, we will invest a further £2 million of our funds in a comprehensive Customer Relationship Management (CRM) system. This will be the hub through which we manage all interaction and communication with our customers.

4.12 Our vision is to bring together customer consumption, connection, location and circumstance information to deliver the most comprehensive service and support in our industry. We will integrate information flows from our field operations to the CRM to allow us to provide fast, accurate details on power outages and restoration times. This will address one of our customers' biggest concerns and allow them to understand why their power has gone off and when it will be restored, using either traditional voice contact or self-service via our website, mobile app or social media feeds.

4.13 The diagram below shows our conceptual data and systems integration plan to achieve this.



4.14 In the early stages, we will develop functionality which allows us to enhance our Priority Services Register (PSR) information, extending this to cover the wider range of vulnerable customers who may not meet the PSR criteria but who nevertheless require extra support and assistance from us.

4.15 We will be able to offer streamlined and more cost-efficient connections services through a better understanding of network capacity at both high and low voltage levels. We see this as being vital to supporting low carbon technology uptake and our strategy to support distributed generation connections, particularly towards the end of RIIO-ED1 and beyond.

4.16 Integration with other companies' and agencies' systems, to the extent practicable and allowed under the Data Protection Act, will provide a platform to develop multi-agency support and assistance programmes. Our conceptual data and systems integration plan is shown below.

4.17 We think this is an exciting time for our industry. There are many challenges to overcome however we are fully committed to setting a new service benchmark and investing in the people, processes and technology to deliver it.

Safety

4.18 We do not compromise on safety. It is embedded in our company's culture and values and is our number one priority for our people, contractors, customers and all who may come into contact with our network.

4.19 This value means much more than meeting our legal obligations; we are dedicated to achieving the highest standards of health and safety for all our customers, employees and contractors. Our objective is not only to protect people and the environment but also to contribute positively to improving overall health and wellbeing.

4.20 Our aim is to minimise the risk of unwanted events occurring through a mix of education, awareness, training and investment in the network where appropriate.

4.21 We work to a zero harm health and safety strategy. We will continue this strategy during the remainder of DPCR5 and throughout RIIO-ED1. Our strategy supports and aligns with the national strategies set out by the Health and Safety Executive and the Energy Networks Association and is underpinned by our health and safety management system, which is certified to the OHSAS 18001 standard. We demonstrate health and safety leadership at every level of within the business. Our overall strategy and performance against it is set and monitored at board level by a Health and Safety Committee.

4.22 Our commitment to safety has yielded demonstrable improvements in performance. This is measured through the rate at which accidents occur, which has continued to show a steady decline over the last five years.

4.23 Our prime safety output measure is compliance with all applicable legislation. There is no financial incentive attached to this in RIIO-ED1 and we think that is right. We take our responsibilities very seriously and believe we should go beyond simple compliance.

4.24 There are a number of investment programmes which are aimed at reducing specific safety risks on our network in RIIO-ED1.

Our output proposals for RIIO-ED1

	Category	Objective	Measurement	Target	Date
1	Safety	Site security	Number of sites with additional measures installed	800	2023
2	Safety	Safe climbing	Number of pylons with latchway installed	1,600	2023
3	Safety	Asbestos management	Number of substations remediated	9,073	2023

Stakeholder feedback

Stakeholders think safety should be one of our top priorities.

4.25 As well as operating a safe network, they would like us to address issues such as metal theft and asbestos. They also told us that we should do more to promote safety awareness to the young people in our community.

Output proposals

We will continue to comply with all regulatory and legislative requirements. We will maintain and enhance our safety programmes and deliver a number of specific health and safety investments through our programme of risk control measures as detailed below.

Site security

4.26 Like most network operators, we have seen increases in break-ins and theft from our sites over the last few years. Metal theft and vandalism pose specific risks to our customers and our workforce and we have taken major steps to improve security during the current price control. It would be prohibitively expensive and impractical to protect our entire network, given that it is spread over an area of 12,500 square kilometres. We will therefore build upon our current programme which allows us to protect as many circuits and customers as possible whilst maintaining a balance with cost and our ability to deliver.

4.27 We believe this is best achieved by protecting our major substations and overhead lines through a mix of measures including;

- Improved fencing
- CCTV installation
- Watermarking
- Asset tagging

4.28 We will also replace all locking systems at our sites with modern electro mechanical systems. We have developed innovative ways of marking our assets, cables and earth tapes and we are conducting trials with Lancashire Constabulary. These have led to a number of successful prosecutions because of the conclusive evidence our marking systems provide. We will continue this programme during RIIO-ED1.

Safe climbing

4.29 Our tallest structures are the pylons (steel towers) which support our 132kV lines. They stand around 27 metres tall – the equivalent of six double-decker buses stacked one on top of the other.

4.30 Our people work on these towers all year round in all weather conditions. We are installing specialist fixings called latchway systems which allow our people to secure themselves to the tower structure during climbing and when working at height. We have already commenced this work and by the start of RIIO-ED1 1,600 towers will remain to be addressed. We will complete work on these remaining 1,600 by 2023.

4.31 Where appropriate, we will install these systems as the first phase of any planned tower work. This means we get the most efficient installation cost and our people benefit from the reduction in safety risks whilst carrying out the additional tower work.

Asbestos management

4.32 The majority of our network assets were installed in the 20-year period between 1949 and 1969. At that time the dangers of asbestos were not understood and this material was used widely in substation construction and insulation. We are progressively removing asbestos from substations, or making it safe, and will continue this programme through RIIO-ED1. We will remove or make safe the asbestos at 6,080 indoor and 2,652 outdoor distribution substations and 341 of our major substation sites.

Training and education

4.33 We will continue to invest in training our people to ensure compliance, competence and awareness in all areas of health and safety, including leadership and behavioural safety programmes.

4.34 We are committed to promoting customer awareness of the potential safety risks associated with contact with the electricity distribution system and how customers can avoid danger.

4.35 We will continue to identify potential risks and any incident trends that indicate increased risk due to changes in customer activities. Where necessary we will develop and implement appropriate communications to increase customer awareness of risk and precautions (see Annex 10).

4.36 The types of communication methods we will use will include:

- Information available on our website
- Attendance and presentation at relevant events
- Running specific public safety events
- One-day events at schools through our Bright Sparks programme

Investment

4.37 We plan to spend £40 million in RIIO-ED1 to ensure our network is safe and continues to comply with all applicable legislation. This is an increase of around 79% on our current levels, which is driven primarily by the rise in site security investment in response to metal theft and malicious damage incidents.

Social obligations

This Output is designed to help us play our full part in assisting those customers who are in vulnerable situations or circumstances.

4.38 We will use the British Standard definition of a vulnerable customer to provide clear and consistent guidelines for our people to work to. This definition was originally applied to financial services, however, we think its broad intention ‘to protect consumers who are put at a disadvantage in terms of accessing or using a service, or in seeking redress’ provides a good overarching principle for our approach.

4.39 The Output is focussed on the role we can play in developing partnerships and working relationships with companies, charities, local and national government agencies and others in the North West to deliver enhanced advice, support and service to our vulnerable customers. Our social strategy also includes improved customer data management, enhanced network resilience to protect high concentrations of vulnerable customers and advising on energy efficiency.

One of the main considerations for stakeholders in assessing the value of an investment decision is the extent to which it protects or assists vulnerable groups. Our stakeholders universally supported funding priority services for vulnerable groups.

4.40 Engaged Consumer Panel participants were asked to consider their willingness to pay for various investment options without knowing the cost implications and subsequently with the cost implications disclosed. In most cases, willingness to pay decreased once the cost was known.

4.41 For a small number of decisions, however, willingness to pay increased once cost was considered and these included enhanced services to electricity-only customers and priority service for vulnerable people. Our stakeholders recognised that the relatively low cost of these measures delivered a significant benefit for vulnerable people. They considered these investments to be socially worthwhile and to offer good value-for-money. This view was ratified by the results of our national consumer survey run by Populus which indicated that customers in the North West were willing to pay more for these services.

Track record

We are determined to play our full role as a responsible organisation.

4.42 We have an active and comprehensive Corporate Social Responsibility (CSR) programme which allows us to apply our resources to deliver a positive impact on the communities we serve in the North West. Our programme is fully supported by our shareholders, who are committed to Environmental and Social Governance (ESG) as part of their overall investment strategies.

4.43 We are working with Business in the Community (BITC) and using their approach to develop an effective CSR strategy, tailored for the needs of customers and communities in the North West. As a national charity dedicated to transforming business and communities, BITC can objectively assess our approach based on best practice not just in our industry, but in all industries. They provide robust feedback and guidance on our CSR initiatives which allows us to maximise the positive impact they have.

4.44 We report annually on our progress and participate in the BITC Corporate Responsibility index. We entered the index for the first time in 2012, achieving a score of 54%. This gives us a useful benchmark from which to develop our CSR programme. We are fully committed to achieving gold status – where we have to score more than 90% – within the next five years.

Our Output proposals for RIIO-ED1

Our social obligations commitments for RIIO-ED1 are, we believe, the most progressive in our industry.

	Category	Objective	Measurement	Target	Date
4	Social	Responsible organisation	BTIC Index	Gold	2018
5	Social	Enhanced PSR service	Up-to-date and accurate information	Contacting PSR customers every two years	Ongoing
6	Social		Better targeted services using data that will become available over the course of ED1	Ongoing enhancements identified through stakeholder engagement	Ongoing
7	Social	Improve services for vulnerable and Priority Service register customers	Enhanced training for all customer-facing front-line people	Improved identification of and advice to vulnerable customers	Ongoing
8	Social		Welfare package support and temporary power supplies	Deliver services during planned or unplanned power interruptions	Ongoing
9	Social	Resilient supplies to vulnerable locations	Upgrade network reliability for 56 Hospitals and 87 distribution substations	Complete network automation investment	2017
10	Social	Mitigate fuel poverty	Reduce average RIIO-ED1 prices compared to DPCR5	16%	2015-2023

Priority services

4.45 We maintain a Priority Services Register (PSR), which allows us to identify those customers who are most dependent on our services and develop tailored support to assist them. We have more than 235,000 customers – about 10% of our total – on our PSR.

4.46 PSR customers receive enhanced support from our Customer Contact Centre during power cuts or planned interruptions. We keep them informed of progress and likely time before power restoration. Where necessary, we make arrangements for the British Red Cross to visit them to deliver personal support, which may include the provision of food, blankets or other help.

4.47 We publicise our PSR service and eligibility criteria on our website and we have trained our customer-facing people to recognise potential PSR customers and, where this is the case, provide a proactive registration service.

4.48 Our PSR service will be reviewed by a working group every six months to examine service delivery performance and identify opportunities to enhance it.

Vulnerable and Priority Services Register customers

4.49 We are committed to supporting our customers in all situations where they may be vulnerable. We already offer enhanced support to our PSR customers; however, we will extend this to include our vulnerable customer base (see Annex 9).

4.50 Our vulnerable and PSR service customers enhancement plan for the remainder of DPCR5 and throughout RIIO-ED1 includes the provision of:

- Site visits, if required, for all connections applications
- Contacting all customers on our PSR once every two years to ensure we have up-to-date and accurate information
- 14 days notice of planned interruptions through face-to-face contact
- Identification of high volume PSR areas on our network, i.e. those parts of the network where the number of PSR customers who would be impacted by an outage is disproportionately high
- Custom support for high volume PSR areas, taking account of supply interruption duration, time of day and weather conditions
- Proactive contact within 30 minutes of a supply interruption to determine if additional support is required
- Emergency relief including food, blankets, lighting and personal support
- Alternative power supplies for customers for planned interruptions or under fault scenarios over three hours where there is a defined medical dependency on electricity and we cannot provide a reasonable time for restoration of the supply.

4.51 We are committing to invest our own funds in a comprehensive data strategy, integrating network and customer data to provide us with a complete picture of who is connected to our network, how they use it and how we can best serve their needs. Our commitment is to invest these funds during the remainder of DPCR5 to make sure we are ready to implement and deliver additional customer benefit from the start of RIIO-ED1. We are not seeking any funding for this support.

4.52 Our preparatory investment in our data strategy will provide an excellent platform for the direct and targeted support services we will provide in RIIO-ED1. It will also help us manage the dynamic nature of customer vulnerability, as we recognise that it can be a temporary state.

4.53 We are not relying on technology alone though. Our first line of response is our people. Our people come into contact with our customers in a number of different ways and they are uniquely placed to help deliver vulnerable customer support. We will implement enhanced training for all our customer-facing front-line people including our contractors which will help them identify signs of vulnerability and advise customers how we can offer additional help and support.

4.54 Other agencies, whether statutory, social or charitable can help as well. We plan to engage these groups and other key stakeholders in quarterly vulnerable customer workshops, which will ensure our support provision remains current, targeted and comprehensive.

4.55 We will simplify our communications across all our channels. We want our customers to understand what help we can offer and how to access it in simple, jargon-free and accessible terms.

4.56 We will continue to deliver our enhanced PSR support but to a wider customer base. We will also continue to deliver direct welfare support and temporary power supplies to ease the inconvenience caused by planned or unplanned power interruptions.

4.57 We will continue to work with our colleagues at the British Red Cross, the National Energy Action (NEA) and develop new relationships with the Clinical Commissioning Groups (CCGs) of the National Health Service, local authorities, housing associations, charities, network operators, energy suppliers and others such as Consumer Futures to find further, more inclusive ways of delivering vulnerable customer support.

4.58 We will introduce a new role, vulnerable customer manager, to provide the appropriate management focus to enhance our customer culture and service initiatives.

Resilient supplies to vulnerable locations

4.59 There are a number of locations on our network where high concentrations of vulnerable customers are found, including hospitals, nursing homes and sheltered housing. As these locations are likely to have significant populations of vulnerable customers over a long period of time, it is sensible to invest to make the network in these areas more reliable.

4.60 We have recently completed analysis which shows that 56 hospitals are connected to our high voltage network. We have an excellent track record of automating fault identification and restoration on our network and we think it is sensible to take steps to provide additional resilience to the parts where the hospitals are connected. This investment will reduce the risk of prolonged supply outages.

4.61 The total cost is £1.2 million. We will deliver half of this in DPCR5 and complete the remainder by 2017.

4.62 We have also identified 87 distribution substations in areas of high vulnerable customer concentration (more than 50 per substation) where customers have seen two or more interruptions over the last five years as a result of a higher voltage fault. We plan to fit remote control and network automation to all of them, again with the objective of improving reliability and restoring power quickly in the event of an outage. We will invest £1.6 million to do this, completing the work by the end of 2017.

Fuel poverty

4.63 Fuel poverty affects an increasing percentage of our population. By 2016, it is estimated that around 17% of people in England will be classified as fuel poor.

4.64 We think the best response is to keep prices down and our business plan delivers that. If our plan is accepted, our average prices in RIIO-ED1 will be 16% lower than average prices in DPCR5. In addition, we will be able to accelerate the benefits of RIIO-ED1 into the last year of DPCR5 by avoiding the need to increase our prices in 2014-15.

4.65 There are other ways we can help including providing information and advice to customers about the services and options available to them and working with others to help co-ordinate and optimise the level of support delivered through various sources.

4.66 Our data strategy will help us understand customer circumstances and energy usage. This will help us engage more effectively with local authorities, agencies and electricity suppliers to develop and deliver targeted fuel poverty assistance. In particular, we will look at how we can work with gas distributors and others to consider solutions such as renewable heat technologies or connection to the gas grid as cost effective ways of relieving fuel poverty.

Energy efficiency

Customers can benefit from improved energy efficiency

4.67 We will work with other agencies to provide customers with information on the efficient use of energy. Our work with National Energy Action (NEA) is helping to refine and develop the energy efficiency content of our education programme Bright Sparks, to deliver practical lessons in energy use and consumption to the children of the North West.

4.68 We are committed to improving our own energy usage through improvements to our properties, vehicle fleet and electrical losses through the network assets.

Electricity theft

4.69 Electricity theft increases the cost of electricity for all customers and creates safety issues through interference with our equipment. We are committed to tackling electricity theft and have retained a dedicated revenue protection service despite the licence obligation being removed in 2007. We work closely with other agencies including the police, environmental health and electricity suppliers to combat theft. We are leading the industry in this area and made the proposals for industry code changes which were subsequently approved by Ofgem and brought the governance arrangements for revenue protection onto a more formal basis.

4.70 We have expanded our revenue protection team, as we believe there is significantly more theft taking place than is currently being detected. We see this as a self-funding activity using the legal mechanisms available to us to recover our costs.

4.71 For further details of our activities in this area see Annex 19 – Losses Strategy.

Investment

4.72 Most of our proposals for social obligations Outputs do not have a requirement for specific investment on the network. The only exception is where we propose to upgrade supply reliability in areas of high vulnerable customer concentration.

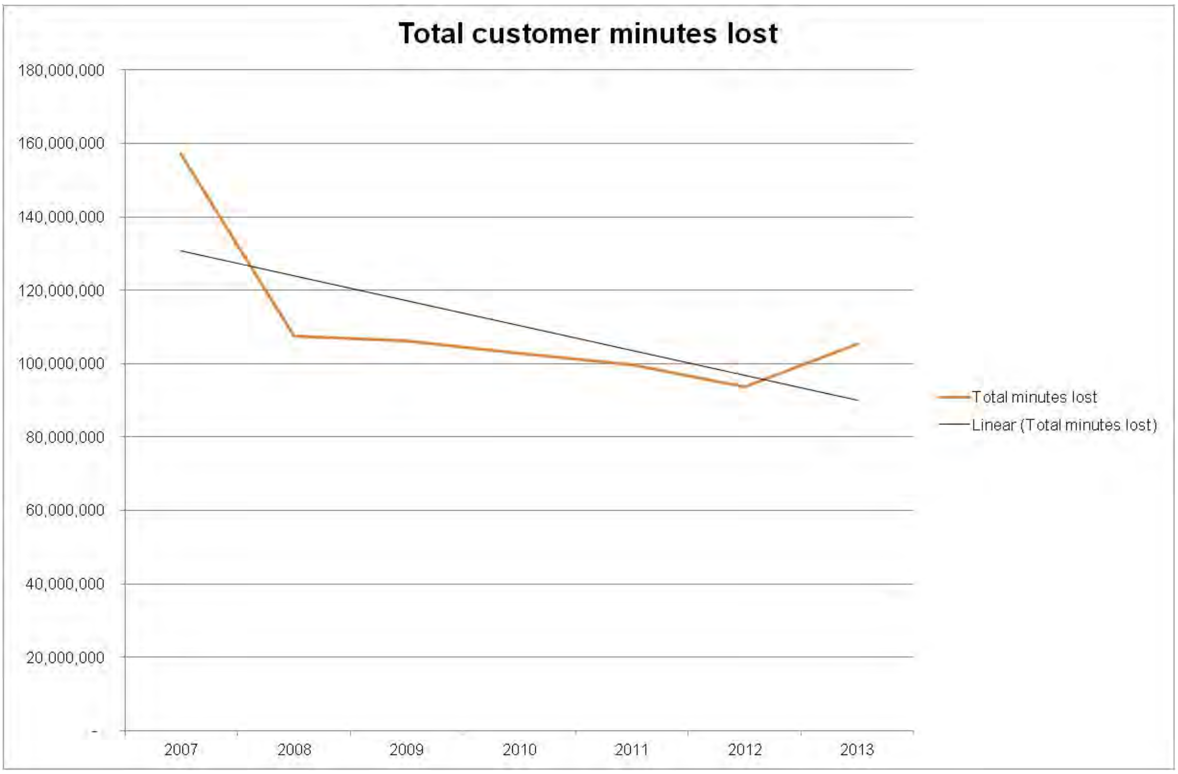
4.73 We will fund the additional support and welfare services we plan to offer, along with the investment in our Customer Relationship Management hub. Incentive funding is available if we demonstrate our stakeholder engagement is robust, comprehensive and embedded in our business. We will be delighted if our efforts are recognised through this, however our commitments are not dependent on it in any way.

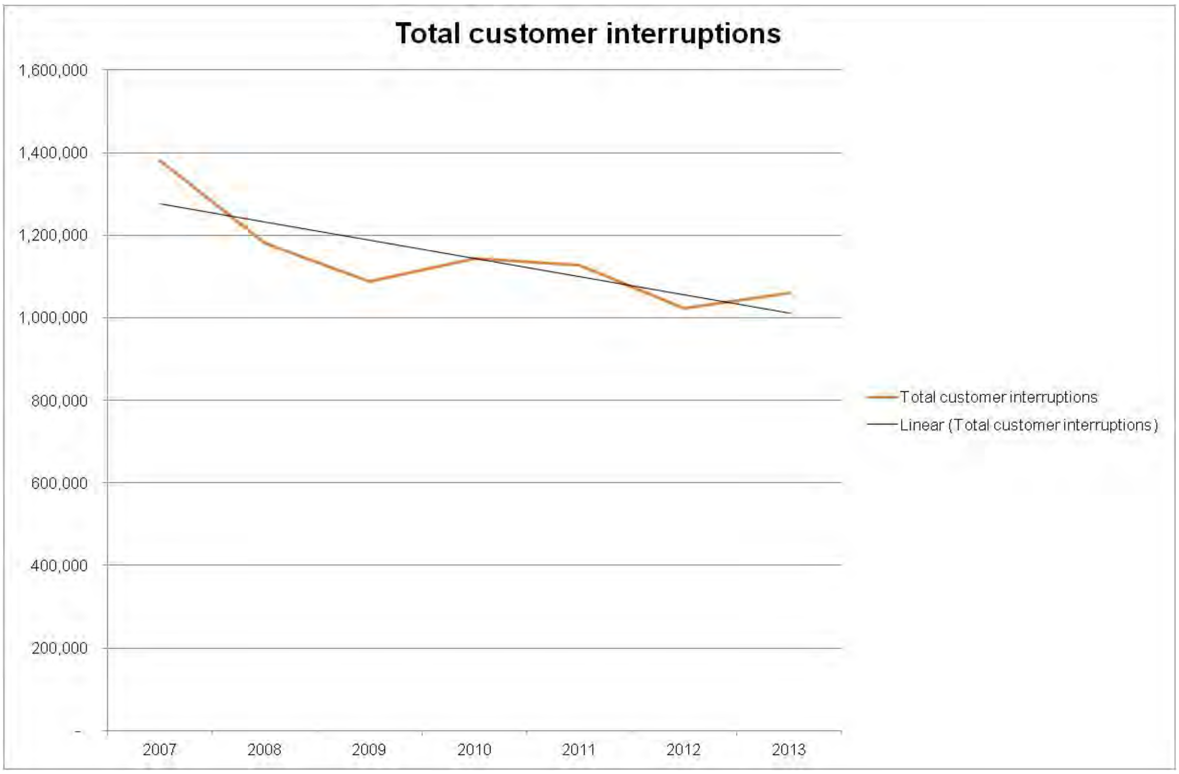
Reliability and availability

Reliability (power cuts) and availability (time without power) are the two key measures of network performance.

4.74 On average our customers experience a supply interruption less than once every 27 months and are without power for less than 45 minutes every year. This means our network availability is better than 99.99%.

4.75 The main reliability and availability Output is measured in terms of Customer Interruptions (the number of times a customer experiences a power cut) and Customer Minutes Lost (the period of time for which the power cut lasts). Ofgem sets target levels for these measures based on historic performance and comparisons with other organisations. We consistently beat these targets and when we do, Ofgem makes the next set of targets even tougher. This drives us to continually improve the level of service we provide





4.76 Reliability and availability is generally improved through a combination of network automation and improved operational fault response. These improvements depend on us maintaining the network's underlying performance through a programme of efficient replacement, repair, maintenance, refurbishment and reinforcement.

4.77 This programme needs to be carefully balanced to ensure we make the right short- and long-term decisions. For example, diverting effort to improving quality of supply through short- term fixes would produce an immediate performance improvement but could undermine the future capability of the network and build up a backlog of future renewal work. In many cases this will result in a higher whole-life cost. We have compared refurbishment versus replacement options for our assets, informed by careful evaluation of the difference in costs and benefits, to deliver a balanced programme which offers the optimum mix of performance and value for our customers.

Stakeholder feedback

Unsurprisingly, our stakeholders think keeping the lights on should be our number one priority.

4.78 Support for 100% reliability, whilst cost-prohibitive, was high with many stakeholders believing that we should improve our 99.99% reliability score.

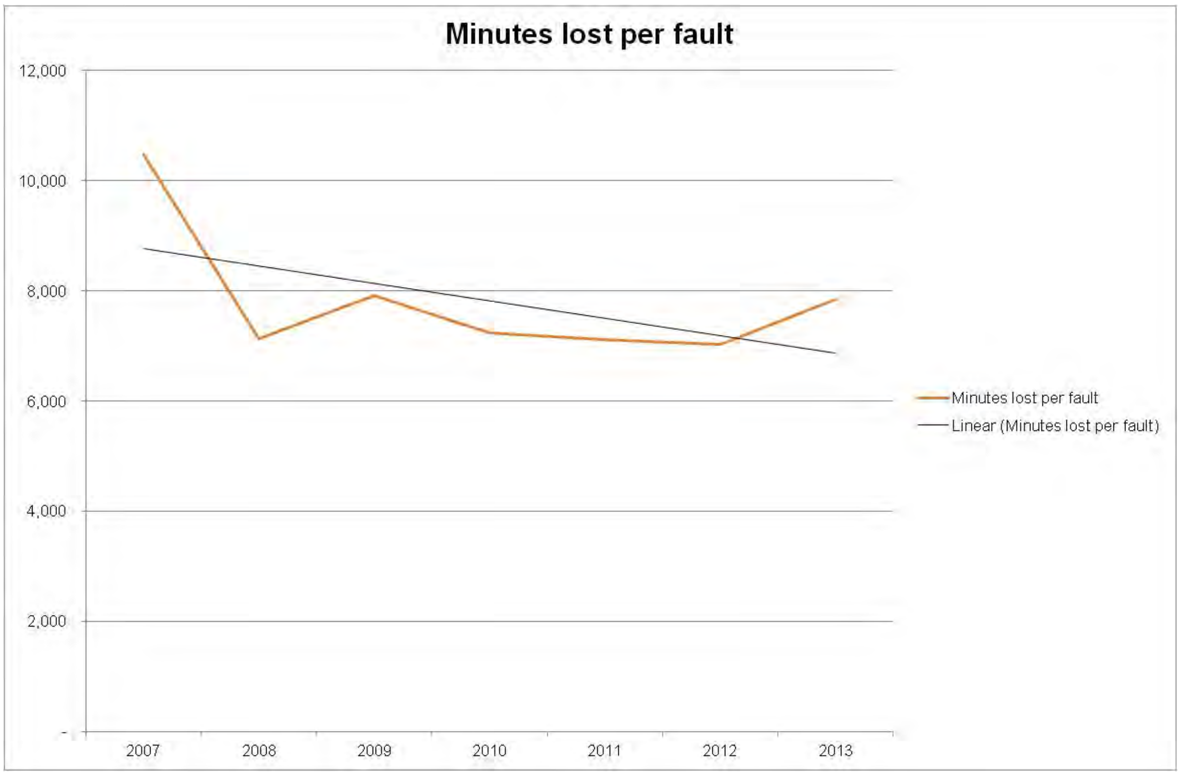
4.79 Domestic customers were more interested in short-term improvements, however our political, commercial and business stakeholders supported our view that we need to ensure we have a sustainable network, now and in the future.

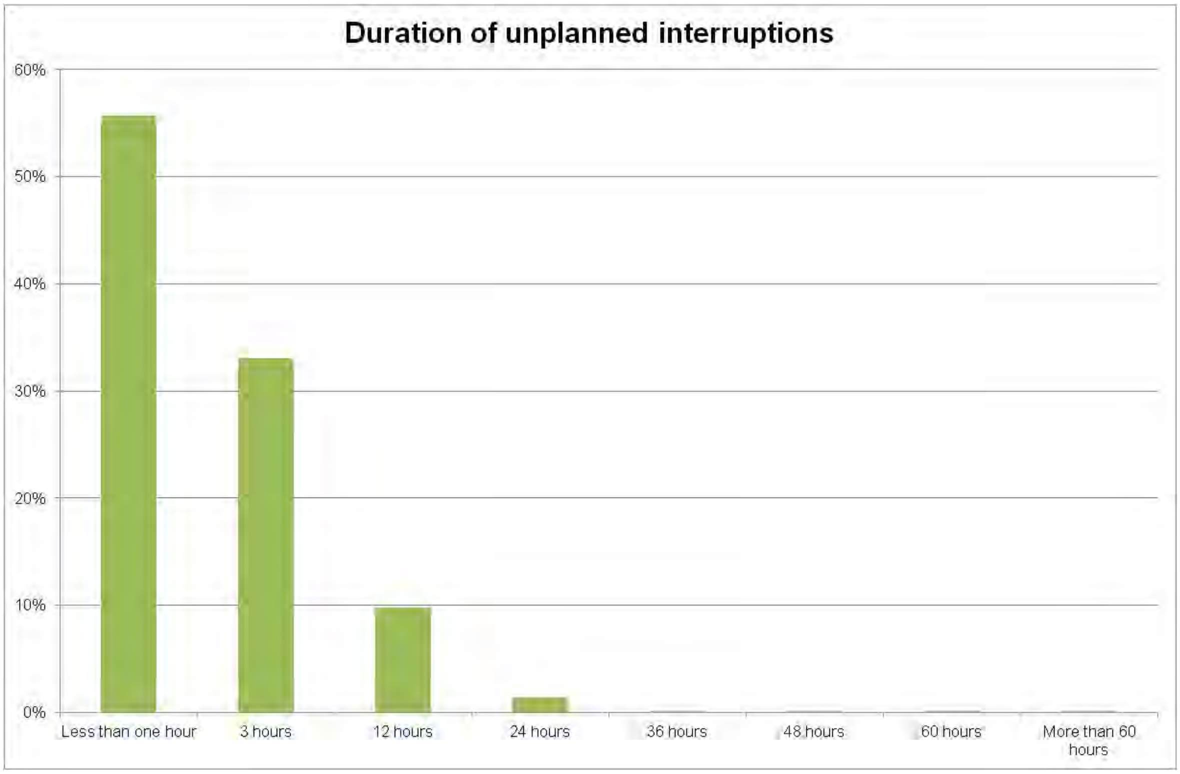
4.80 Most customers expressed a willingness to pay slightly more to invest for future reliability. Our regional development stakeholders want to see continued investment in infrastructure to support future social and economic growth.

Track record

Since 2007 we have delivered a 16% reduction in total Customer Interruptions and an 18% reduction in total Customer Minutes Lost. In 2011/12, each unplanned fault affected 77 people compared to 92 five years previously.

4.81 For those who did experience a fault, power was restored in an average of 92 minutes compared to 114 minutes five years ago. When a customer's supply is interrupted, the duration of the interruption is less than two hours in 80% of cases. We have also delivered a consistent reduction in our overall network fault rate.





Output proposals

4.82 We will improve reliability and availability through a combination of investing to maintain our network's underlying performance, investing in additional control and automation and improving our operational response times.

Quality of Supply

We will deliver a further 20% reduction in Customer Interruptions and Customer Minutes Lost by 2019.

4.83 We have deliberately chosen 2019 as the target date as smart meter rollout will be almost complete by then. The presence of near-universal smart metering on the network will radically change our awareness and recording of performance issues, particularly on the lower voltage networks, providing an opportunity to redefine performance targets and incentive schemes.

4.84 Performance enhancement will be delivered through targeted improvements to make the network smarter and equip our fault teams with the latest fault finding equipment. Some of these initiatives take advantage of developments from our innovation programmes.

4.85 We will install:

- Smart fuses which can autonomously restore supply in the event of a fuse failure without a site visit being required
- Remote control facilities with 3G communications to enable switching operations to be carried out remotely
- Automation which reconfigures the network to switch to alternative supplies without requiring the intervention of a control engineer

4.86 Quality of Supply is subject to an incentive mechanism which generates penalties and rewards depending on our performance against Ofgem's targets. Consequently we expect to fund our automation plans from the incentive revenues and have not included any allowance request in our plan.

	Category	Objective	Measurement	Target	Date
11	Reliability	Improve overall reliability	Customer interruptions	20% improvement on 2012 position	2019
12	Reliability	Improve overall reliability	Customer Minutes Lost	20% improvement on 2012 position	2019

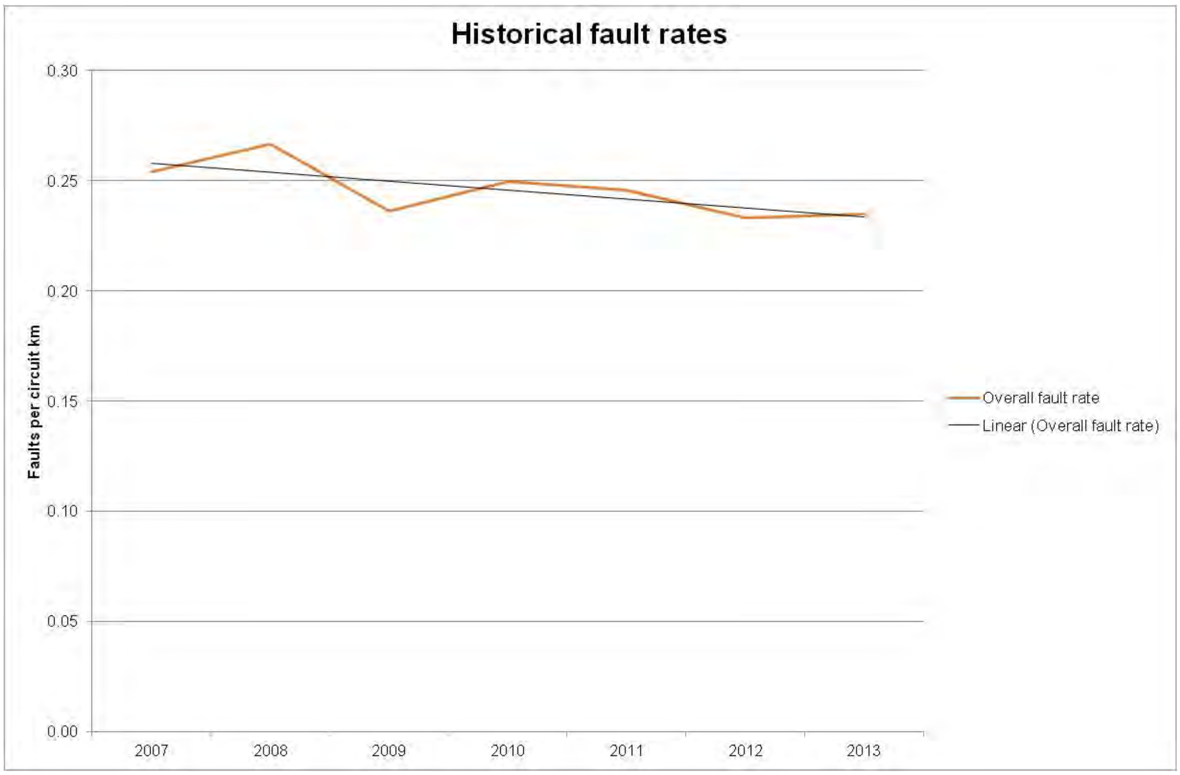
Asset health

We manage the overall health of our assets to ensure the long-term sustainability of our network.

4.87 Failure to do this would result in increasing failure rates over time and deterioration in reliability and safety. We consider how to balance our interventions over the longer term (DPCR5, RIIO-ED1 and beyond) to ensure the work that needs to be done can be carried out sustainably and without storing up problems for the future.

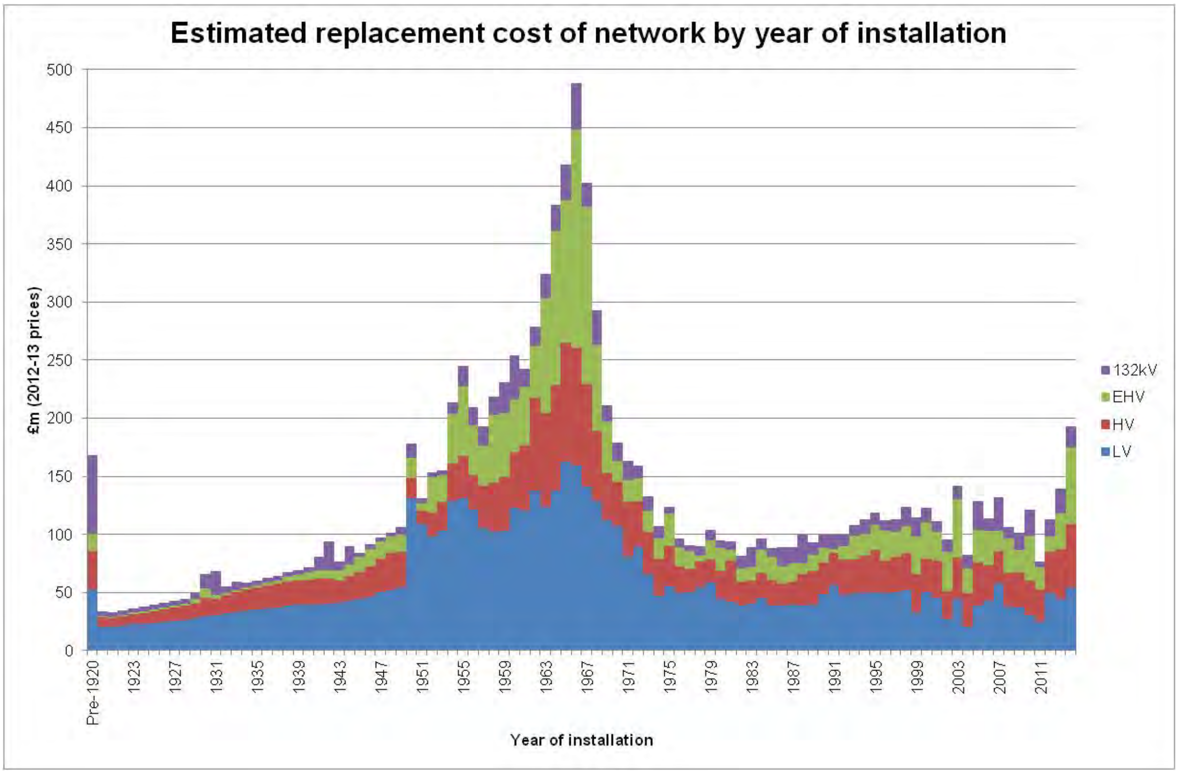
4.88 Much of our asset base was installed in the 1950s and 1960s and has given good service through its lifetime. Some of it is even older, dating back to the original transmission network in the 1930s and local area supplies before that. Our asset management techniques are BSI PAS-55 certified. We pioneered the use of Condition Based Risk Management (CBRM) and are particularly proud of the fact that this has been widely adopted across the electricity distribution sector.

4.89 CBRM helps us monitor and predict our assets' performance and behaviour, which in turn allows us to design cost-effective intervention strategies. We estimate the risk profile of the network using Risk Indices. These are measures which calculate probability of failure and its likely consequences. This allows us to model how our total risk changes over time and the impact of our intervention programmes on total risk. By understanding the risk profile across our entire network we develop targeted interventions rather than blanket approaches (see Annex 2).



4.90 Our asset replacement and refurbishment programme represents the optimum balance of cost and risk. We developed the programme using our established Asset Management policy (see Annex 11), CBRM, deploying innovative solutions and Cost Benefit Analysis of alternative interventions (eg replacement, refurbishment, life extension, extended maintenance, fix-on-fail etc).

4.91 The use of refurbishment options, many developed under previous innovation projects (such as the re-generation of transformer oil) enables us in some cases to deliver the majority of the benefits of replacement for a fraction of the cost. Our RIIO-ED1 plan includes £50 million of savings through the use of targeted refurbishment in lieu of replacement.



4.92 Our planned interventions by asset group include:

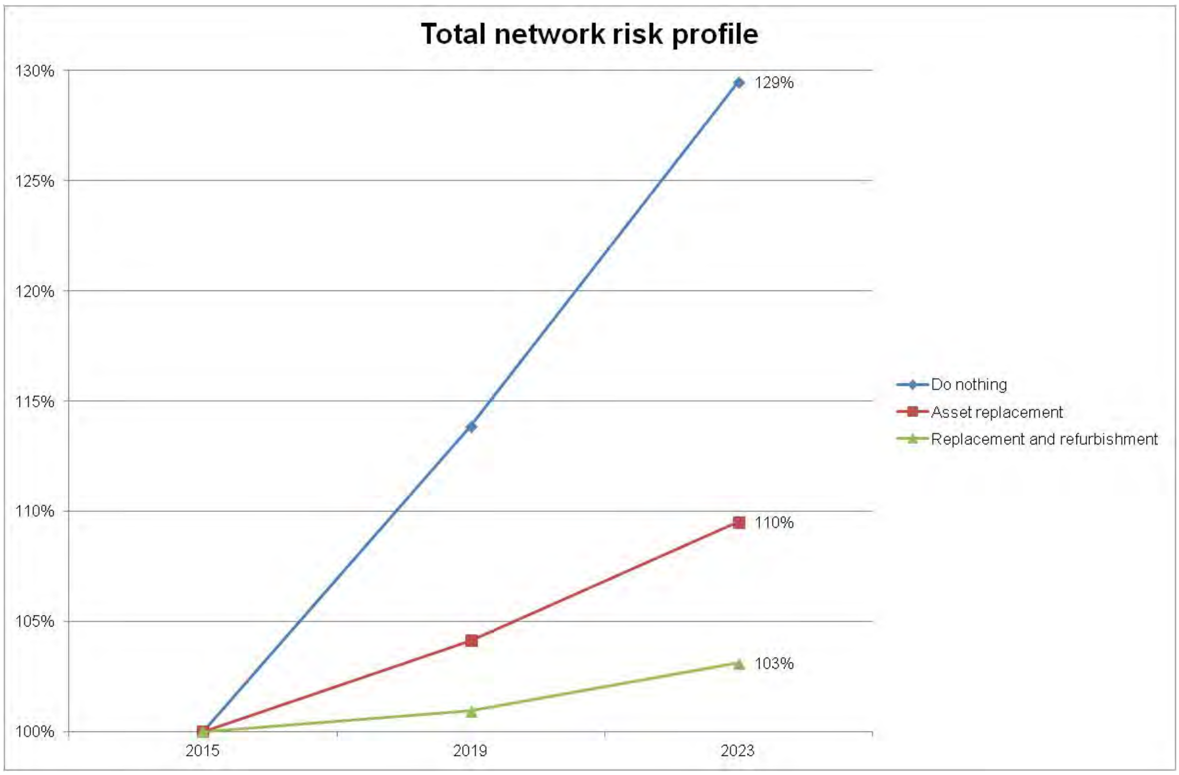
- Woodpole overhead lines – we will replace a substantial proportion of woodpoles during DPCR5 as part of our Electricity Safety Quality and Continuity Regulation (ESQCR) compliance programme. In RIIO-ED1 we are planning to maintain our woodpole asset population with a defect management regime
- Steel towers – are made up of a number of components and as such are much easier to refurbish than woodpoles. Our management regime for these assets is one of ongoing refurbishment and painting
- Underground cables – as deterioration rates are not clear and the asset base performs well we are continuing a programme of replacing poor performing sections and lengths of pressurised cable. We are also investing in research to better understand the condition of the lower voltage networks
- Above ground plant – is easier to assess and predict. Many of the existing assets, mainly transformers and switchgear, will have to be replaced by assets with enhanced capabilities to support the move to a low carbon future
- Civil works – these are often the parts of our network that customers see most frequently. We have developed a CBRM approach to these assets which is helping us to target priority areas

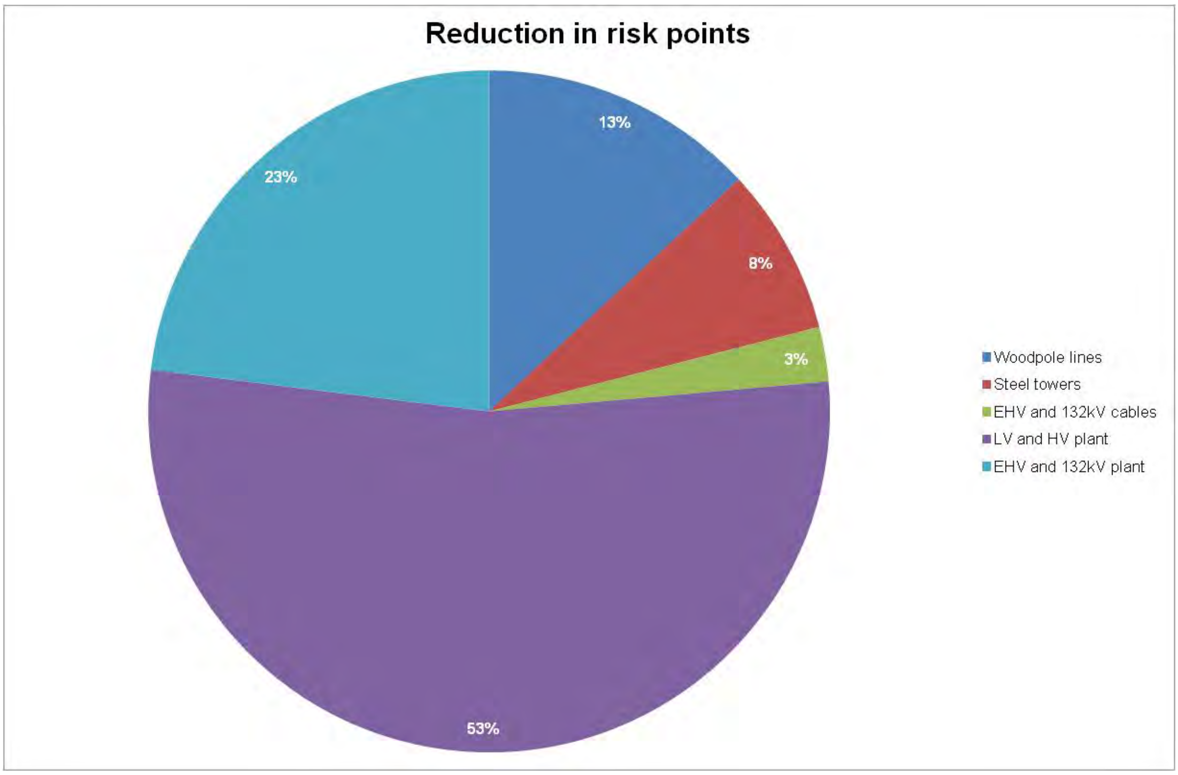
4.93 Our plans for RIIO-ED1 will help us control risk and manage our assets' natural degradation, helping us meet our reliability improvement targets with affordable solutions.

4.94 In terms of assessing alternative programmes of investment for the replacement and refurbishment of our network assets, we have examined a 'do nothing' position, which includes no investment in asset replacement or refurbishment. This would result in a 28% increase in total network risk by the end of RIIO-ED1 compared to the end of DPCR5. We have evaluated options for each asset group using our CBRM tools and their forecast effect on managing total network risk through RIIO-ED1 (see Annex 2).

4.95 Our proposed investment programme is a mix of asset replacement and refurbishment informed by the application of Cost Benefit Analysis. If we undertake asset replacement only, the risk of asset failure will increase by 9% over its DPCR5 levels.

4.96 If we implement replacement and refurbishment this risk will only increase by 3%.





4.97 The graph shows the total network risk position for these three profiles. We believe our selected investment programme is the best value option, as the cost to hold the network risk at the same level throughout RIIO-ED1 would require an additional investment of £53 million in asset replacement which we do not believe would be economically justified for the marginal benefits gained.

4.98 For some of our equipment, particularly buried assets such as cables, it is difficult to measure condition accurately. For these assets, we propose to measure our performance using fault rates, ie the number of faults we experience each year divided by the amount of equipment we have. These fault rates can vary significantly year-on-year depending on the weather and other factors, but can show the poorly-performing parts of our network over a period of time.

4.99 We propose to report against these measures annually and commit to the following output targets for RIIO-ED1:

	Category	Objective	Measurement	Target	Date
13	Reliability	Maintain overall network health	Overall risk index	Maintain within 3% of 2015 position	2023
14	Reliability	Maintain overall network health	Fault rate	Maintain within 10% of current average	Ongoing

Network resilience

As well as maintaining performance under normal operating conditions, we also have to plan for more extreme circumstances.

4.100 Recent events such as the flooding incidents in 2005 and 2007, storms of Christmas 2013, and other companies' experience due to extreme 'one-off' situations have led to an increased focus on network resilience, that is the network's ability to withstand these extreme events.

4.101 These events can range from the local but significant (eg an attack on a specific strategic site), through regionally significant (eg a major storm or flooding incident) to the regional impacts of a national event (eg the whole system going down as it has in Auckland, New Zealand, India and the east coast of America in recent times).

4.102 This winter has seen sustained storm force winds coupled with flooding across our region. Our previous investments in remote control and network automation technologies have delivered huge benefits for our customers during these events. They have enabled us to consistently restore 90% of affected customers within 12 hours and coupled with our customer contact centre improvements have allowed us to deliver consistent excellent service to our customers. Throughout the storms our priority has been to restore our customers and alleviate some of their concerns through proactive compensation payments.

4.103 Our resilience plans have not been drawn up in isolation. DNOs have worked together to consider the appropriate response to these threats and collaborated with government departments with responsibility for emergency planning. We have also liaised closely with our regional partners who have an interest in co-ordinated responses to such events.

4.104 As a result of these discussions, we plan to do the following during RIIO-ED1:

- External attack risk – we will protect our most significant substation assets against external attack in line with national guidance from the Centre for the Protection of National Infrastructure (CPNI)
- Black Start risk – we will ensure the network has enough back up capacity to be re-started should the whole system ever go down (known as Black Start). This largely involves ensuring substations have sufficient battery backup and that communications systems still work in the event of a complete mains power failure
- Flooding risk – we will continue our programme of protecting substations against the risk of flooding. All our major substations identified as being at risk will be protected against a once in 100-year flooding risk (in line with the national specification ETR138) by the end of RIIO-ED1
- Single dependency risk – we will change the network where it is overly dependent on a single physical structure (eg cable bridge)

4.105 Our network resilience programme is summarised below.

	Category	Objective	Measurement	Target	Date
15	Reliability	Strategic site security	No. sites with protection to approved CPNI standard	2	2018
16	Reliability	Ensure all major substations have appropriate backup capacity	No. substations with 72 hour backup capability	517	2023
17	Reliability	Complete flood protection programme at all major sites	No. higher voltage substations protected against 1/100 year flooding	56	2020
18	Reliability	Re-configure the network where appropriate to ensure redundancy in event of major incident	No. sites completed	5	2018

Worst Served Customers

4.106 Although our average performance is very good, and continues to improve, we are aware that a number of customers experience relatively poor service.

4.107 This is generally due to the customers' locations and the characteristics of the network that serves them. In DPCR5 any customer who has experienced 15 higher voltage (ie HV and above) interruptions in a three-year period with a minimum of three faults per year is defined as a Worst Served Customer and we have a specific allowance to improve their service.

4.108 Stakeholder feedback supports greater service equalisation. Our RIIO-ED1 programme will therefore target all customers who have experienced 12 or more higher voltage interruptions in a three year period and ensure that no customers meet this criterion by 2023.

4.109 Our proposed Outputs for RIIO-ED1 are:

	Category	Objective	Measurement	Target	Date
19	Reliability	Improve performance for Worst Served Customers	Reduce the number of customers qualifying as worst-served	No WSC over 12 events	2023

Asset loading

In addition to managing asset health, we also monitor and predict the impact that future changes in electricity demand will have on the loading of our infrastructure.

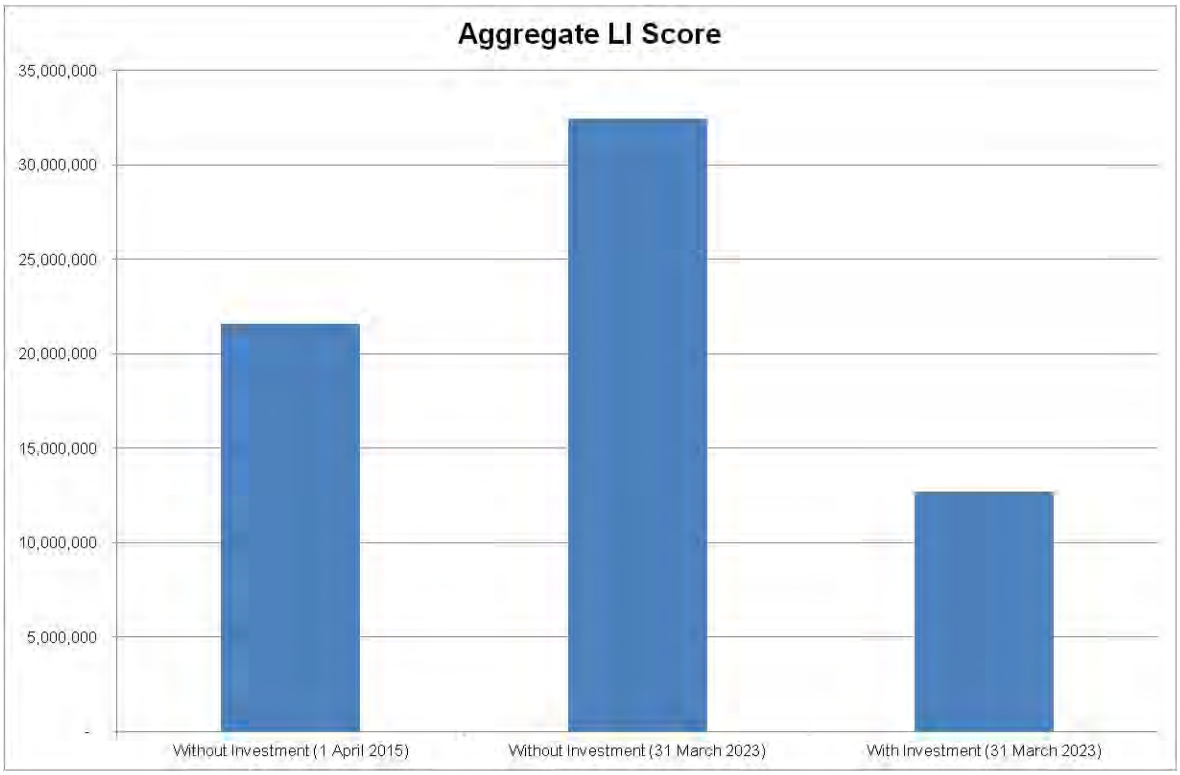
4.110 If demand exceeds capacity then:

- In the event of a fault, we will be unable to restore all customers from alternative sources meaning that some customers could be off for an extended period of time
- Running overloaded assets for extended periods of time presents a safety risk, wears them out more quickly and requires them to be replaced much earlier than would normally be the case

4.111 We measure asset loading using a Load Index (LI) on our higher voltage substations. The LI compares the maximum demand on an asset to its capacity. We look to balance utilisation with an appropriate amount of spare capacity to accommodate short-term increases in demand.

4.112 Our investment programme is based on reviewing where substations and demand groups have breached or are forecast to breach their capacity limits. The 1 – 5 LI scale gives us a way of articulating this. Each actual or forecast substation at LI = 5 is investigated to determine the most appropriate intervention option and an associated investment planned.

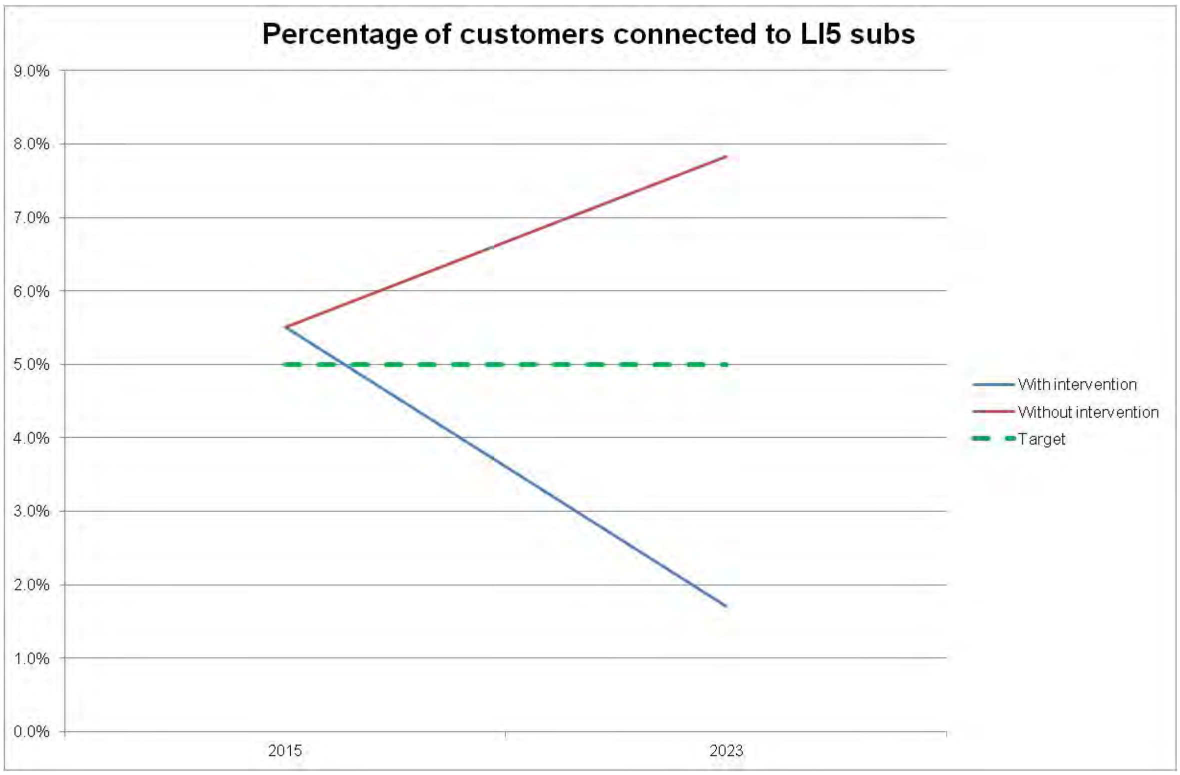
4.113 For RIIO-ED1, the total impact of the planned programme can be measured through weighting the substations in terms of customers connected to them.

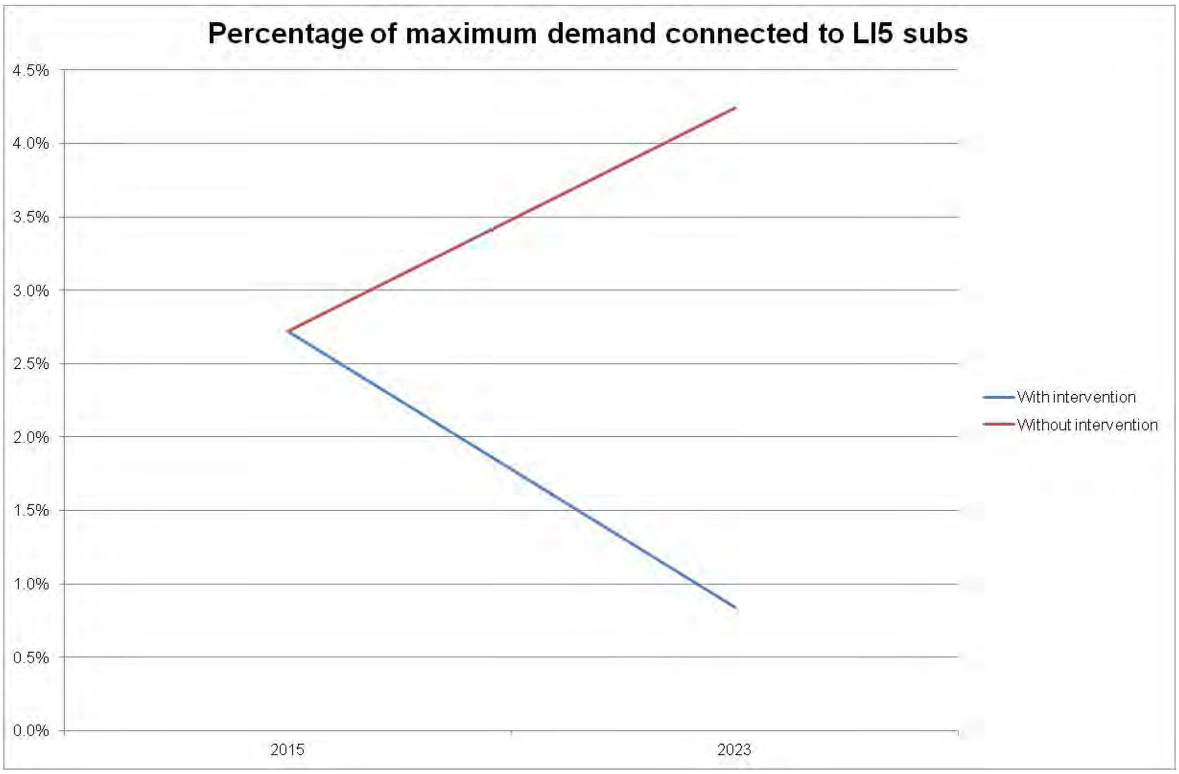


4.114 We can also articulate this in terms of the numbers of customers connected to overloaded substations. We forecast that this will be around 3% at the end of DPCR5. If we make no further investment, this will increase to 9% by 2023, however, we will reduce this to 1% by delivering our planned programme.

4.115 The actual needs and requirements of the network depend on future load growth, which is uncertain and difficult to predict. Therefore we do not propose to commit to specific LI targets for this programme as it could incentivise unnecessary investment. In RIIO-ED1, a re-opener mechanism will operate to share the financial risk if the pattern of demand growth and consequent investment requirements are substantially different from forecast.

4.116 We will also invest in switchgear on our 6.6kV network to ensure there are no constraints to the adoption of Low Carbon Technologies (LCTs).





4.117 The Outputs we will deliver are:

	Category	Objective	Measurement	Target	Date
20	Reliability	Ensure that the loading risk of the network is appropriately managed	Proportion of customers connected via overloaded substations	<5%	Ongoing
21	Reliability	Ensure that the loading risk of the network is appropriately managed	Install larger capacity transformers and/or additional interconnection at our major substations	20	2023
22	Reliability	Ensure that network constraints to the connection of LCTs are removed	Replace switchgear at locations where its current rating is likely to prevent the extensive connection of LCTs	295	2023

Investment

4.118 In total, we plan to spend £641.6 million in RIIO-ED1 on replacing and refurbishing our network, which is at about the same level as our DPCR5 expenditure.

In addition, we will spend £3.4 million on improving performance for our Worst Served Customers. We plan to invest £27.0 million to improve network resilience and £108.3 million to increase capacity.

Customer satisfaction

Our customers contact us for many different reasons, but most of the time it is because their power has gone off.

4.119 When this happens, and indeed whenever a customer contacts us, we need to respond quickly and with the level of professionalism and expertise they expect and deserve. The customer satisfaction Output measures how well we do this.

4.120 There are three main parts to the measure:

- Customer satisfaction survey
- Complaints
- Stakeholder engagement

4.121 The customer satisfaction survey examines how well we handle general and more specific enquiries from our customers. The complaints measure ensures we deal with customer complaints quickly and fairly.

4.122 Stakeholder engagement is designed to ensure our processes for engagement with stakeholders and service provision for vulnerable customers are robust, effective and embedded in our business decisions.

4.123 Our customer service performance has been good but we want it to be the best. We are committed to putting customers at the heart of our business. We are making substantial investments in technology, people and processes which we are delivering with the same level of urgency and professionalism which has underpinned our network performance improvements. We are confident this will deliver a level of performance which will rival the best, not just in our industry, but across all industries.

Summary of Output proposals

Our customer service targets for RIIO-ED1 will put us as the forefront of service in our industry.

	Category	Objective	Measurement	Target	Date
23	Customer service	Broad measure of Customer Service	Composite score	85%	2015 onwards
24	Customer service	Complaints	Resolved within one day	90%	2015 onwards
25			Resolved within five days	100%	2015 onwards
26	Customer service	Stakeholder engagement	Ofgem's evaluation of annual stakeholder engagement submission	Pass part 1 submission	2015 onwards
27	Customer service	Guaranteed Standards	Due compensation	100%	2015 onwards
28	Customer service	Storm compensation	Payment at 18 hours		Now onwards

Stakeholder feedback

Our customers' first priority is to be provided with accurate and timely information about the status of a supply interruption, its cause and the expected restoration time.

4.124 When asked which method of contact customers prefer, the clear favourite remains the telephone. We are, though, beginning to see increasing support for other channels including email, web chat, text message and social media. When customers do contact us, they want us to take ownership of their issues and be able to provide resolution without bouncing them between different parts of our business.

Track record

Historically, our industry has been asset-focussed. Our network of cables, poles, towers and transformers is the backbone of the service we provide to those who depend upon us.

4.125 We understand though, that needs, attitudes and priorities change over time and we need to make sure our business keeps up with these changes. As a result, we are taking positive steps to switch our focus from assets to customers and put customers at the heart of our business.

4.126 During 2013, our customer satisfaction performance has gradually improved and been more consistent which shows that our improvement plans are working. Detailed analysis of the customer satisfaction data shows a key area of focus to be unplanned messaging and minor connections. Plans are in place to alter the layout of the messaging service, enhance the information providing including tips to help during a power outage and reporting to highlight customers who have made repeat contact. For connections, the main focus areas are to provide a consistent approach for communication through the whole process and to reduce the time to connect.

4.127 At the beginning of 2012 we created a dedicated customer directorate, which is responsible for all aspects of customer service and care. This has allowed us to consolidate all customer-facing parts of our business in one, cohesive organisation.

4.128 At the end of 2012 we launched our flagship Customer Contact Centre, the result of a £1 million investment of our funds. This is the primary hub for all customer contact activities and provides the foundation for our one stop shop objective, where any team member can resolve a customer issue on first contact, irrespective of the nature of the enquiry.

4.129 Technology is not the only answer, though. Our customers want to deal with people and we are taking steps to make sure we recruit and retain the right people. We do not recruit call handlers. We recruit and train customer service agents; people who have a career interest in customer service rather than simply working in a call centre; people who can connect with our customers, understand their needs and deliver the right level of support and resolution.

4.130 To support our customer service agents in delivering the highest standard of service, we will ensure they receive refresher training every year in all elements of their roles from their understanding of the electricity distribution network to the basics of customer service. This training is altered following outputs of learning from our call quality monitoring processes. Our current performance for call politeness of our staff from the Ofgem customer satisfaction survey is 94%.

4.131 We are committed to customer service excellence and are working with the Institute of Customer Service (ICS) to help us develop our plans. We employ their testing methodologies in our recruitment process; they facilitate benchmarking visits to allow us to see best practice in action and we meet with them quarterly to review and develop our customer service plan. Our ambition is to achieve both ICS TrainingMark and ServiceMark certification by March 2015.

4.132 Our biggest challenge is providing accurate and timely information about our works; what we are doing, why we are doing it and when it will be repaired. During the remainder of DPCR5 we will implement enhanced communications between our field teams, the Customer Contact Centre and our customers to allow us to do this.

4.133 Our training programmes for our contact centre agents will ensure our customers have a positive first contact and enable us to identify special individual requests that can be addressed appropriately. The new technology will ensure contact centre agents will have access to more real time information to be able to tailor the services to our customers and personalise their experience. We are also working hard to introduce other communication channels (online, app and mobile) to provide a wider range of ways for our customers to interact with us.

4.134 We intend to ensure all engagement with our customers is easy and in the style the customer prefers, we are working hard to enhance all channels of communication to introduce web chat, additional online functionality, increase in social media and face to face alternatives. As part of the customer relationship management system functionality all communication updates for social media, text messaging, telephony, web chat and on line will come from one central feed to ensure a consistent message and allow customers to move between communication channels.

4.135 We are committed to offering customers accessible information through a number of self-service channels. We have recently launched an online fault map and will supplement this with an online planned outages schedule in the near future.

4.136 We have implemented an enhanced planned outage notification process, where we supplement the normal notice card with a text message six days before the outage. We send a reminder text two days before the outage and on the day of the outage we send further texts with expected restoration time and confirmation of supply restoration.

4.137 There are times when our response does not meet our customers' expectations and this results in a complaint. Since the beginning of 2012 we have improved our one-day complaint resolution performance by over 100%. We will continue to make further positive progress for the remainder of DPCR5. As a result of the service improvement we have implemented, by the end of December 2013 our year to date performance for one day complaint resolution was 58% which is a 23% increase and sets us on course for meeting the challenging targets we have set ourselves in the RIIO-ED1 period.

4.138 Other initiatives we have implemented and will build upon include the automatic payment of Guaranteed Standards of Performance (GSoP) payments to all customers on our Priority Services Register, proactive advertising of GSoP entitlements to our entire customer base and voluntary payment of the GSoP equivalent of £25 to all customers when we do not provide them with seven days' notice of a Planned Supply Interruption.

4.139 As a result, we have set ourselves a target of 85% performance against the Broad Measure of Customer Service by the end of DPCR5. We are committed to maintaining this as a minimum level of performance in RIIO-ED1.

Output proposals

Broad Measure of Customer Service - customer satisfaction survey

We understand that when customers need to contact us, they want us to deal with their enquiries quickly, efficiently and politely.

4.140 We have a number of channels through which customers can contact us however, for the time being, telephone contact remains our biggest channel. In RIIO-ED1:

- We will answer all calls within two rings
- Our abandoned call rate will not exceed 1%
- Where customers want to talk to one of our customer service agents, we will ensure they can do this quickly and easily through various communication channels
- We will provide accurate and up-to-date information and will resolve 90% of all enquiries on first contact
- We will achieve a call quality score of at least 90%
- We will provide a restoration time for all outages; updating our High Volume Call Answering (HVCA) systems, web sites and social media in real time and proactively provide call-backs, text or email updates
- We will integrate our online fault map and planned outage map with our CRM to send proactive notification to customers via text and email

Complaints

In RIIO-ED1 we will resolve 100% of complaints first time.

4.141 We will resolve 90% of complaints within one day and the remaining 10% within five days.

4.142 We understand that sometimes customers will not be satisfied with our solution or explanation and they may seek independent advice to help resolve their complaint. We will actively encourage them to do this and make them aware of the Ombudsman process. We are confident that we will have done everything possible to avoid an Ombudsman referral however when these do happen, our target is to have 100% of all decisions found in our favour.

Stakeholder engagement

We were one of only three DNO groups to pass both stages of Ofgem's stakeholder engagement incentive trial in 2012. In the 2013 Stakeholder Engagement Incentive Scheme, we built on our 2012 success by significantly improving our score and ranking – we were awarded 7.9 out of 10 (second place out of the six DNO groups) and considerably closing the gap on the lead DNO.

4.143 This gives us confidence that our process is robust, comprehensive and delivering the results we need to shape our business and reflect our stakeholders' priorities. We are not complacent, though, and we continue to strengthen our stakeholder activities. We are working with AccountAbility to ensure we adopt and deploy best practice (see Annex 1).

4.144 Our description of our 2012-13 stakeholder engagement programme for the reporting year ended 31 March 2013 has been independently assured by Deloitte LLP in accordance with the International Standard on Assurance Engagement 3000 (ISAE 3000 – a standard that has been designed by the International Auditing And Standards Board (IAASB) to assure non-financial data).

4.145 Our approach is detailed in Sub-annex A1: Stakeholder engagement strategy (from entry to Ofgem's 2013 Stakeholder Engagement incentive scheme) of Annex 1: Stakeholder methodology and responses. In this we describe how we have developed our stakeholder engagement programme applying the three principles of the AccountAbility's AA1000 Principles Standard, inclusivity, materiality and responsiveness.

Guaranteed Standards

Guaranteed Standards payments are there to ensure that on those rare occasions where our performance is unsatisfactory, our customers are compensated for their inconvenience.

4.146 Overall, we deliver a success rate of more than 99% against Guaranteed Standards performance. When our performance falls below our expectations we will proactively contact customers who may be due compensation payments shortly after the event which has given rise to the entitlement. We recognise, though, that our information is not always perfect and we supplement our proactive efforts with comprehensive information on our website. We will continue to refine and develop our website and our other communications channels to ensure the most up to date information is available to our customers.

4.147 Of course not all customers have internet access so we will supplement our online activities with other forms of communication including working with energy suppliers to distribute Guaranteed Standards information to customers and proactively making them aware of Guaranteed Standards entitlements when they contact us by phone or mail.

4.148 Payments to customers on the Priority Services Register will be made automatically, as our processes will ensure we are aware of when, and for how long, they have been interrupted. As smart meters are rolled out during RIIO-ED1, we will integrate this data with our CRM technology to expand our capability to make automatic payments to all entitled customers.

Storm compensation

4.149 Following the storms over Christmas 2013, we asked our Engaged Panel what they thought appropriate storm compensation payments would be. The majority of our engaged consumers told us that being paid £54 after 18 hours without power due to a storm is about right. We agree, and despite there being an exemption available for severe storms that allows DNOs to only compensate customers after 48 hours, we have not used this exemption during recent severe weather events in December 2013 and February 2014.

4.150 We were planning to continue with this approach, and consulted our External Stakeholder Panel to ask if we should set a policy of never using the exemption. It is our intent not to use the exemption, however our stakeholder panel were keen for us to maintain an element of discretion.

4.151 We considered the approach of some DNOs to simply double payments, however that still involves a trigger point at 48 hours. Our customers tell us that they want us to keep the trigger point for payments at 18 hours, meaning that we will pay more customers more compensation.

4.152 We know that Ofgem will reduce the threshold for paying compensation after loss of supply in normal weather conditions to 12 hours on 1 April 2015. We considered whether we could avoid using exemptions even after the standard had been tightened. By maintaining the discretion advised by our stakeholder panel we believe we will be able to do this in some circumstances. However, the costs associated with paying compensation to all customers without power for 12 or more hours during the recent exceptional run of bad weather and hurricane force winds would have been prohibitively expensive. In similar circumstances we are likely to pay compensation to all customers without power for 18 or more hours.

Investment

4.153 We believe our customer service costs are among the most efficient in the industry and our plans for RIIO-ED1 are based on continuous performance improvement combined with continued cost efficiency.

4.154 We have not included any allowances for our CRM technology, as the investment will be provided from our funds. The average annual cost of delivering our customer service promises is £3.4 million.

Connections

Connecting customers efficiently and economically is an important part of our business and a crucial service for our customers. It is a service that facilitates economic growth and allows us to support delivery of our stakeholder priorities.

4.155 A requirement to connect to our network comes from three main sources:

- New demand connections – such as supply to a newly built house, housing site or commercial premise
- Distributed generation connections – such as wind farms
- Unmetered connections – such as local authority street lights

4.156 The connections Output is designed to ensure we offer a fair, efficient and competitive service to all connections customers. Our proposals will ensure that we:

- Provide an excellent level of service when responding to customer requests and enquiries, not just at the beginning of the process but all the way through to completion
- Deliver our connections service quickly and efficiently against a set of targets predetermined by Ofgem
- Develop comprehensive measures to engage with and understand the needs of major connections customers and continue our leading approach in supporting competition in connections

Summary of Output proposals

Our connections targets for RIIO-ED1 are among the most ambitious in the industry.

	Category	Objective	Measurement	Target	Date
29	Connections	Engagement	Innovation on connections engagement		2015 onwards
30	Connections	Connection quotation	Single domestic quotations	Six working days	2015 onwards
31			Up to four domestic connections	Ten working days	
32			All other connections	25 working days	
33	Connections	Connection completion	Single domestic quotations	30 working days	2015 onwards
34			Up to four domestic connections	40 working days	
35			All other connections (excluding EHV)	50 working days (from when the customer is ready)	
36	Connections	Connection	Guaranteed Standards performance	100%	2015 onwards

Stakeholder feedback

Our stakeholders, particularly domestic customers, have told us that they find the connections process complex and difficult to understand.

4.157 They want us to:

- Reduce connections costs, as these sometimes mean the difference between projects going ahead or not
- Speed up the process from the first call for a quote to the completion of the network connection
- Make it easier to connect new low carbon technology (including distributed generation) to our network

4.158 Our stakeholder workshops and Engaged Customer Panel informed us that local government and regional businesses were keen for us to ensure our long term plans could facilitate growth in connections demand where needed. We have included connections forecasts and economic growth as key determinants of future network capacity in our business plan.

4.159 We have held seminars with Independent Connections Providers (ICPs) and distributed generation customers to update them on improvements we have made or are planning and will continue this engagement with other major connections customers.

We believe that competition is in our customers' interests as it widens choice, drives improvements in service and reduces costs. We make sure our customers in the North West benefit from competition and have been at the forefront of developing a competitive market for connections in the electricity industry.

4.160 The proportion of our market where there is demonstrable and active competition is a key indicator of our success in this area.

4.161 Our customers can choose who makes their connection for them. We are proud to have been the first DNO to pass competition tests in 2011, when we passed three relevant market segments. We have passed a further three segments in 2013, making more of our markets open to competition than any other DNO. These six segments represent about 80% of the connections market in the North West.

4.162 We have submitted further competition test notices in respect of the remaining three relevant market segments and we believe we have provided sufficient evidence for these to be passed also. We believe that this sector leadership is due to our continuous effort to create a truly competitive market for electricity connections customers in the North West.

4.163 We already offer an innovative Connect and Manage service, which allows generation customers to connect to our network where capacity may be marginal but the case for reinforcement has not been made (ie connect the customer, manage the generation and then decide whether reinforcement is required). This accelerates the connections process for our customers and reduces costs by mitigating the need for reinforcement. We have changed our default connection for solar panels and wind turbines to Connect and Manage in response to engagement with Stockport Council, among others.

4.164 We have also introduced an online facility for providing estimates and managing complaints and enquiries. Recognising that the information needs of customers vary considerably, we have developed a portfolio of approaches to help customers seeking connections.

4.165 We have:

- Developed 'heat maps' to quickly inform distributed generation customers which parts of our network have spare capacity and which have some constraints
- Initiated flexible approaches to reviewing connections options for customers so they do not have to complete multiple applications, particularly for small scale jobs
- Facilitated drop in sessions so that customers can have access to our planning and design people prior to making a formal application
- Provided our records and network data free of charge and are working to make this accessible online for our customers
- Implemented a revised process for delivering minor connections to reduce handover times and speed up the overall time to connect
- Introduced 'three-day working' where possible which enables us to excavate on day one, joint on day two and reinstate on day three which reduces the amount of notice we need to give the local authority to undertake the works.

4.166 We have seen increasing levels of customer satisfaction from connections customers through 2013-14 and have achieved an average level of 78.3% in the year to the end of January 2014 compared to 75.7% for the equivalent period in the previous year.

Output proposals

In preparing for RIIO-ED1 we have undertaken a thorough review of our processes and targeted specific initiatives to drive performance improvements (see Annex 12).

4.167 Specifically we are:

- Implementing lean working practices to eliminate non value adding activities
- Identifying opportunities to reduce timescales from quote to connection
- Implementing an on-line quotation system allowing our customers to track progress of their application
- Providing web-based customer access to our connection services
- Progressing a fully competitive market for connections

Connections targets

4.168 Our connections Outputs are customer focussed and designed to ensure we offer a fair, competitive and affordable service. We have reviewed Ofgem's recent proposals on targets in this area and the proposals of other companies. As a consequence we have set ourselves a range of stretching targets which beat Ofgem's proposals and would represent industry-leading performance. These targets have been endorsed by our external stakeholder panel.

4.169 Our performance in meeting the Guaranteed Standards of Performance for connections during the current price control period has been a consistent 99.9%. Our target is to have no failures.

4.170 We will deliver a minimum of 85% customer satisfaction. This will be underpinned by our wider strategy for improving customer service and tailored as required to meet the specific needs of these customers.

4.171 We will provide a quotation after receipt of the customer's initial application on average within:

- Single domestic connections – six working days
- Up to four domestic connections – ten working days
- All other connections – 25 working days

4.172 We will complete the connection after agreeing terms with the customer on average within:

- Single domestic connections – 30 working days
- Up to four domestic connections – 40 working days
- All other connections (excluding EHV) – 50 working days (from when the customer is ready)

4.173 We recognise that customer requirements change and we will review our targets throughout the RIIO-ED1 period to reflect the results of our stakeholder engagement.

Incentive on connections engagement (major connections customers)

4.174 We will develop and implement a comprehensive engagement strategy modelled on our approach to stakeholder engagement. This will ensure we understand the needs of our major connections customers across the different market segments and develop policies, processes and products which satisfy them. We will do this for market segments even where there is no regulatory requirement to do so.

Investment

4.175 The cost and provision of our connections service is recovered from charges to connecting customers.

Environmental impact

We are aware of the impacts we can have and are determined to make a positive contribution to the environmental impact of our assets and our operations.

4.176 We are dedicated to achieving the highest standards of environmental performance, not only by minimising the risk of adverse impacts such as pollution, but through investment in outputs that deliver a positive impact, such as undergrounding of overhead cables. We are determined to play our part in enabling the transition to a low carbon future. This influences both our asset investment plans and our investment in measures to reduce our own carbon footprint.

4.177 We work to an environment strategy that commenced in DPCR5 and will continue throughout RIIO-ED1. Our strategy is underpinned by our environmental management system, which is certified to the ISO 14001 standard.

4.178 We demonstrate environmental leadership at every level of our company. A Board committee sets our environment strategy, objectives and targets and reviews and monitors performance. Our strategy is based on;

- A clear understanding and visibility throughout the business of environmental issues and impacts
- Targeted investment and expenditure in environmental control measures
- Strong corporate governance and performance management
- Continuous learning and improvement
- A systematic approach to environmental management

Our Output proposals for RIIO-ED1

	Category	Objective	Measurement	Target	Date
37	Environment	Reduce losses	Annual GWh saved	11	2021
38	Environment	Reduce carbon footprint	tCO_2e	10% reduction on 2015	2020
39	Environment	Reduce oil lost from cables	Litres lost	<30,000 litres/annum	2023
40	Environment	Undergrounding overhead lines	km removed	80km	2023

Stakeholder feedback

Our national stakeholders expect us to play a full role in supporting the transition to a low carbon future.

4.179 This includes investing to support distributed generation connections, electric vehicles, heat pumps and micro generation (domestic wind turbines and photovoltaic panels). Locally, our customers have expressed a general unwillingness to pay for environmental issues, demonstrating particular reluctance to fund reinforcement for electric vehicles and micro generation unless there is a clear and demonstrable need.

4.180 We forecast the connection of 1,161MW of DG capacity in RIIO-ED1, equivalent to over a quarter of our peak demand. As these developments are undertaken by third parties we have not committed to this as a specific Output, however we will undertake a range of activities to support this development.

4.181 Environmental non-governmental organisations (NGOs), particularly those involved in undergrounding for visual amenity schemes, are happy with our environmental commitment and are keen to see such schemes continue.

4.182 We developed our plan using the stakeholder prioritisation and decision-making process described in Section 3.

Climate Change Adaptation

We have worked with other electricity network companies to identify changes we may need to make to prepare for the effects of a changing climate and implement the work programmes to introduce them.

4.183 A changing climate is likely to have a range of impacts on our equipment. In June 2011 we submitted our first report to the Department of Environment, Food and Rural Affairs (DEFRA) under the Climate Change Adaptation Reporting Power. This summarised the work undertaken to date and in particular how our network may be affected.

4.184 The biggest potential impact is expected to be the increased risk of flooding to our substations. We are already taking steps to install new, and improve existing, flood protection to major substations located on floodplains. Initial studies suggest that other climate change impacts will be of a smaller scale and any necessary modifications to our network will be built into our long-term maintenance, asset replacement and reinforcement programmes.

Output proposals

Loss reduction

We will reduce losses by 11GWh annually through replacing high-loss transformers

4.185 We lose some of the electricity we distribute as it flows through our network. Whilst we can't eliminate these losses, we can take steps to minimise them.

4.186 This generally means installing more efficient assets on our network, particularly low loss transformers and cables. In RIIO-ED1 we will invest around £10 million in fitting low loss transformers, in addition to those replaced in other programmes. This is supported by a robust cost benefit analysis and is detailed in our Expenditure section. When complete, this will reduce losses by 11 GWh annually, saving the equivalent of 5,709 tonnes of carbon dioxide each year[1].

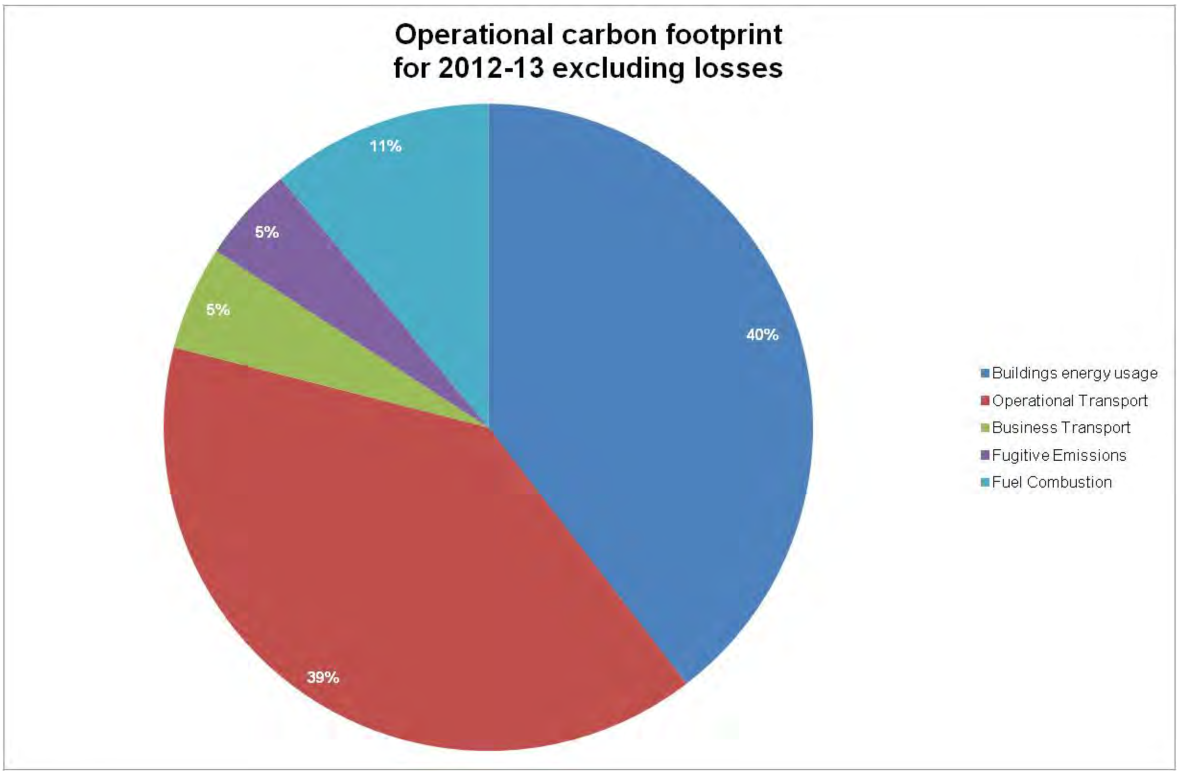
4.187 We will take additional technical steps including using the largest size cable we can justify, fitting capacitor banks to our high and low voltage circuits and fitting harmonic suppression equipment. Further details of our approach and the rationale behind it can be found in Annex 19 – Losses strategy.

Business carbon footprint

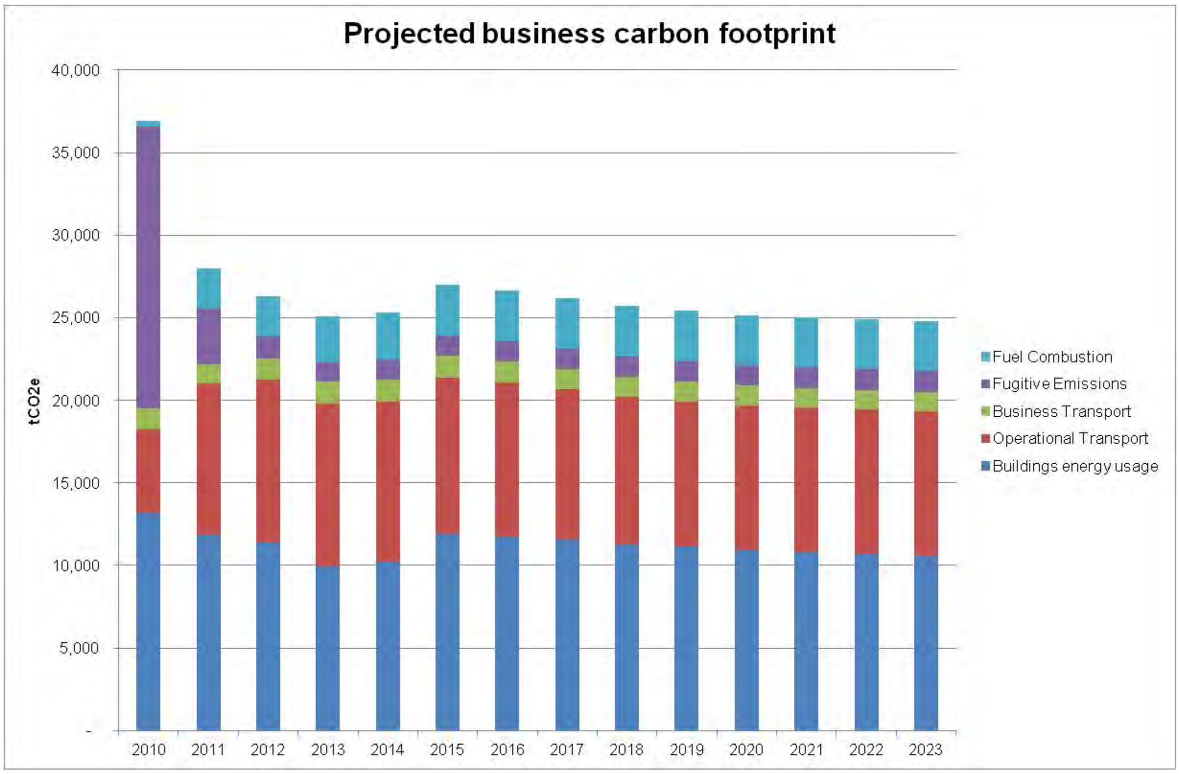
We will reduce our 2015 Business Carbon Footprint by 10% by 2020.

4.188 This will be delivered on the back of a 35% reduction from 2010 to 2015, due in large part to the one-off retirement of early prototype SF_6 switchgear units at one of our major sites in 2011.

4.189 Our carbon footprint is made up of a number of contributing factors as illustrated below;



[1] Losses are not included in our reported Business Carbon Footprint as they are driven by consumption patterns of electricity which we can't control. We can however reduce the contribution of our equipment to overall losses and these planned reductions are equivalent to a quarter of our Business Carbon Footprint.



4.190 Our strategy to achieve further reductions is based on actions for each area as outlined below:

Buildings energy usage

4.191 To reduce the energy usage across the Electricity North West estate we will continue to realise the benefits of the energy efficiency measures implemented in DPCR5. In addition, we will also install smart meters across the estate of non-operational properties with regular reviews of energy usage. Where beneficial, we will integrate energy efficiency initiatives within construction work across the estate and will continue to encourage energy reduction behaviours among staff based in all of our occupied premises.

Operational transport

4.192 To reduce the fuel usage associated with our operations we will:

- Monitor fuel use on a monthly basis against a target of an ongoing volume reduction of 2% per year to 2019
- Utilise our logistics contractor’s vehicles for the efficient delivery of plant and materials
- Remove unproductive grab wagons and other larger vehicles from the fleet
- Closely scrutinise fuel consumption to identify and remedy inefficiencies in the fleet
- Incorporate electric and hybrid vehicles into our fleet

Business transport

4.193 To reduce business transport carbon emissions usage we will continue to encourage reductions in travel among the workforce through the promotion of technologies such as teleconferencing and webinars.

Fugitive emissions

4.194 To minimise the effect on greenhouse gas emissions we will:

- Refurbish property to eliminate the need for air conditioning units and replace older units with newer units with lower emissions
- Continue to install modern SF_6 equipment with lower leakage rates

- Improve leakage detection systems and repair procedures

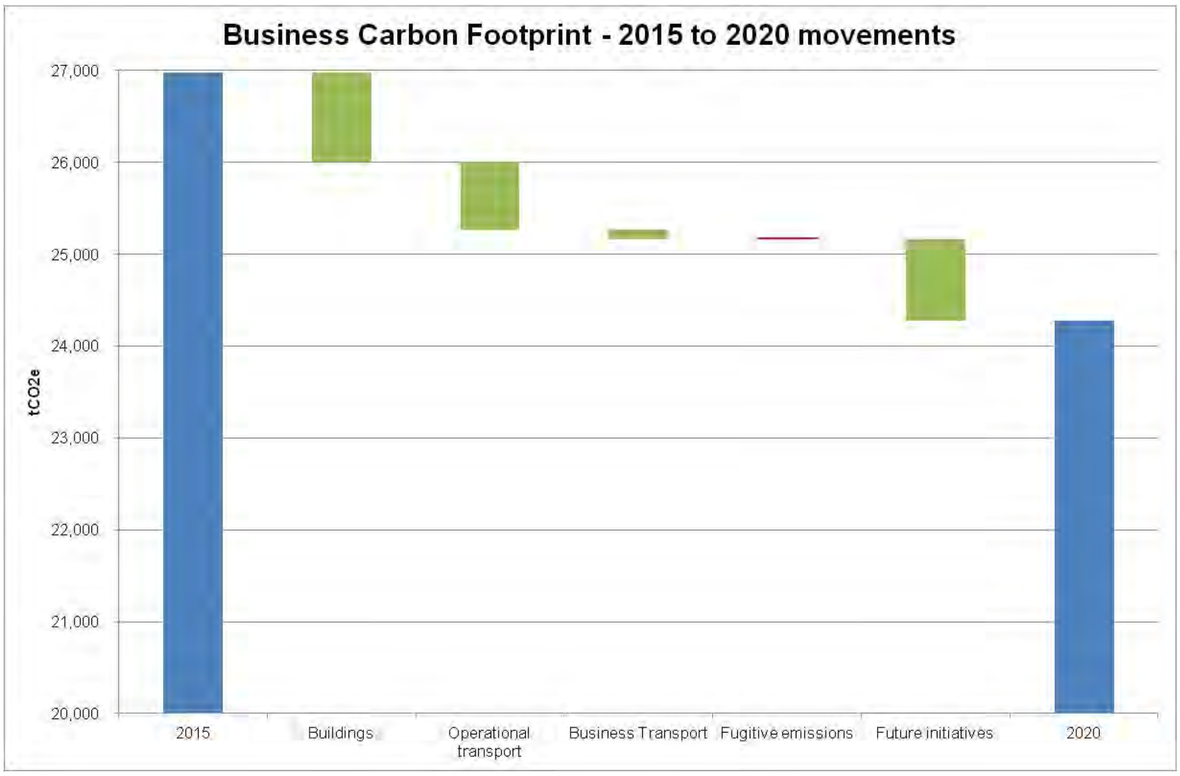
4.195 On SF_6 we will reduce our leakage rate by over 20% from a rate of 0.38% (as a proportion of the mass in service) in 2013 to 0.3% by 2023.

Fuel combustion

4.196 Fuel use by generators is anticipated to remain static in RIIO-ED1 due to the increased deployment of generators to minimise planned interruptions although this will be off-set to some degree by the use of more efficient generators. We will continue in the period to closely monitor usage and promote the use of energy efficient units with minimal use times.

4.197 The combined effect of the above initiatives to reduce our carbon footprint is currently estimated to give a 7% reduction from 2015 to 2020. In order to achieve our 10% reduction target, we will seek to identify further initiatives in these areas.

4.198 The chart below shows our reductions in business carbon footprint from 2015 to 2020.



Oil and gas leakage

We will take additional steps to reduce leakage from oil and gas insulated transformers and cables.

4.199 We will continue to replace early prototype SF_6 switchgear units and replace oil-filled cables with alternative cabling. We will also continue our programmes of substation bunding, which is a further measure against oil contamination, and land remediation.

4.200 We will not be able to eliminate the need for oil insulation completely but we can minimise the amount we use. We have developed an innovative recycling solution using our Central Oil Reprocessing Depot (CORD). This allows us to clean and reuse the insulating oil used in our transformers. Oil reprocessing not only saves around £1 million each year it also reduces the amount of oil that would have previously gone for disposal in landfill by around one million litres per annum.

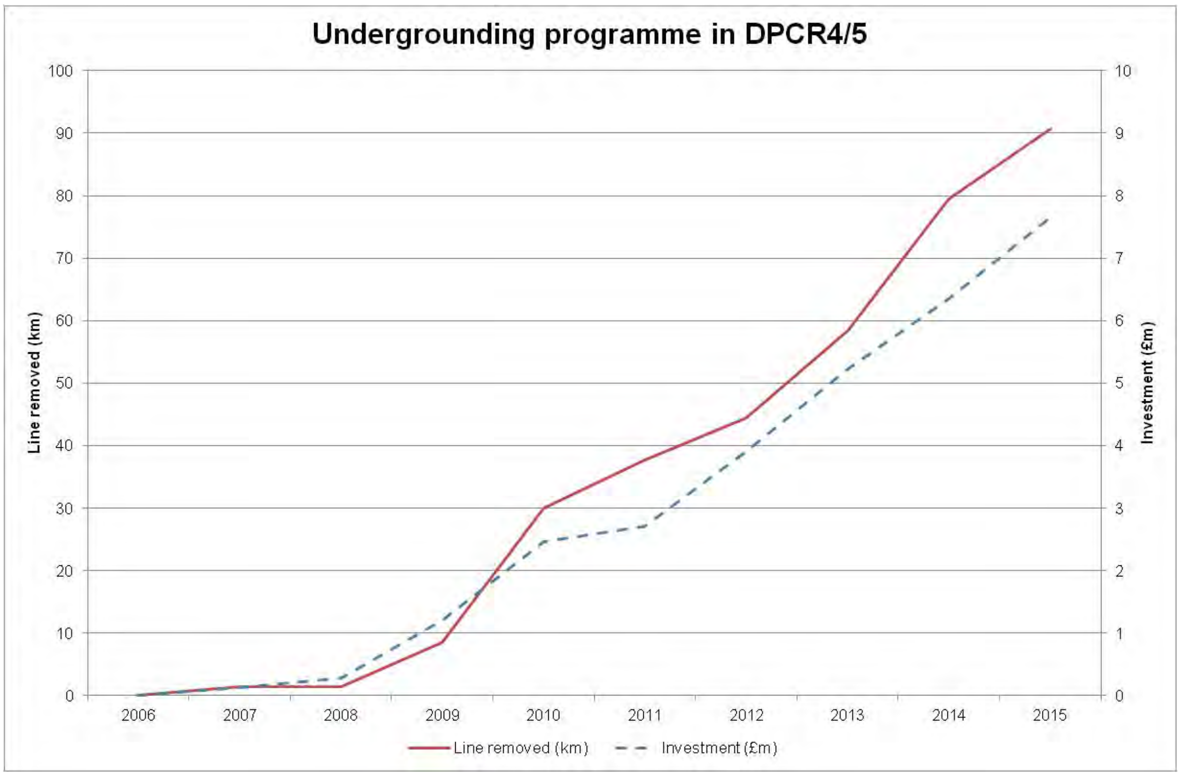
4.201 Our RIIO-ED1 cable replacement programme will replace 57km of oil filled cable, delivering reductions of 131,650 litres of oil in service and 3,900 litres of oil lost per year by 2023, a reduction of 13% compared to 2015.

Undergrounding of overhead lines

Stakeholders see this as a valuable programme and we plan to continue it, investing £1 million per annum throughout RIIO-ED1 to underground approximately 80km of overhead line.

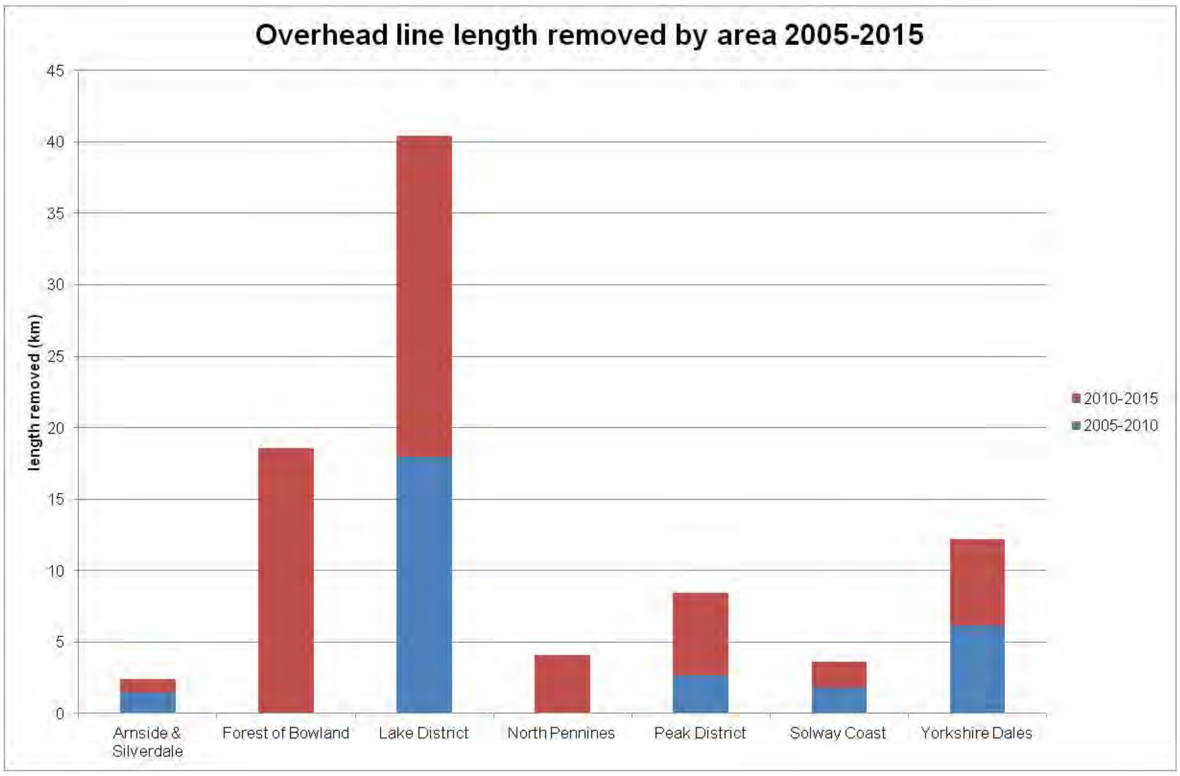
4.202 We worked with our stakeholders to establish a programme of undergrounding for visual amenity in National Parks and Areas of Outstanding Natural Beauty in 2005. This programme has successfully removed lines from a number of prominent sites and become a model of public-private partnership working.

4.203 Since 2005, we have removed over 58km of overhead line and plan to achieve 90km by 2015, at a total estimated cost of just under £9 million.



4.204 We plan the programme in full consultation with the relevant authorities and other stakeholders to ensure that we underground where they see the highest amenity benefit. The detailed selection of areas for undergrounding will continue to be guided by our policy and regional partner priorities. Our planned investment will allow us to underground approximately 80km of existing overhead lines by 2023, although the exact amount will depend on the nature of the sites proposed by our regional partners.

4.205 The extent of overhead line undergrounded or planned to be removed in the 2005-2015 period in each of the seven eligible Designated Areas within our region is illustrated below. These levels reflect the extent of overhead line in each area and we expect these proportions to remain broadly unchanged in RIIO-ED1.



Investment

4.206 Overall, we plan to spend £10million on installing low loss transformers, £9 million on undergrounding overhead lines and £6 million on mitigating other environmental effects in the RIIO-ED1 period.

4.207 Our programme to progressively replace oil-filled cables to reduce oil leakage will cost a further £23 million in RIIO-ED1.

5 Expenditure

In RIIO-ED1 we expect to spend a total of £2.6 billion in maintaining, replacing and upgrading our network, together with carrying out all the other functions required of us as a distribution business.

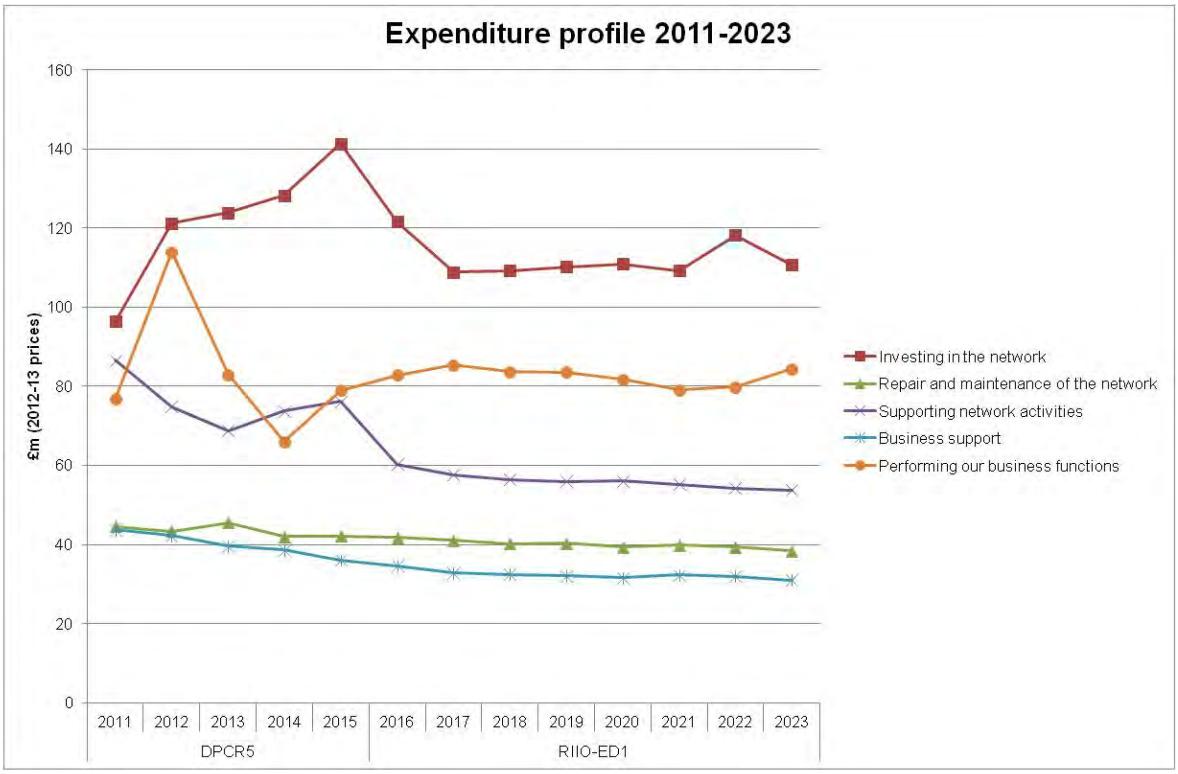
5.1 This expenditure breaks down into five main areas:

- Investing in our network
- Repair and maintenance of our current network
- Supporting network operations and investment
- Business support
- Performing our other business activities

5.2 Our focus is on ensuring we maintain a fit-for-purpose network that delivers for customers, is affordable and can meet the future challenges of demand growth and low carbon technology. In DPCR5 we have been progressively reducing our support costs whilst increasing investment in our network. In RIIO-ED1, replacement and renewal investment requirements are kept relatively flat through efficient delivery and innovative solutions, particularly to network reinforcement challenges. We anticipate a modest increase in reinforcement and connection costs towards the end of RIIO-ED1 in response to an increase in low carbon technology adoption.

5.3 We continue to challenge all aspects of our cost base and are committed to achieving substantial reductions in operating and support costs. We have benchmarked our cost base within our industry and against non-regulated asset-intensive businesses to ensure we are competitive. We are also committing to an annual compound efficiency improvement of at least 1% in each year of RIIO-ED1.

5.4 The following sections look at each of these five expenditure areas, discuss the factors that drive expenditure and detail our major assumptions in each case. All financial values are presented in 2012-13 prices and are gross costs prior to any customer contributions.



Developing efficient costs

Like any business, we constantly challenge ourselves to deliver more value at a lower cost. Our cost performance has improved significantly during DPCR5 and we are committed to continuing this through RIIO-ED1. Following Ofgem's fast-track determination, we have looked again at all aspects at our cost base.

5.5 Our use of framework contracts gives us stability and predictability in the costs our contractors charge us and allows us to drive both quality and cost improvements as a result of our purchasing power. We tend to use five-year contracts to help us do this. All framework contracts are competitively tendered at the outset and are subject to market testing at various stages during their lives. Each major capital project is competitively tendered.

5.6 Our procurement strategy means we optimise the way we buy major items of plant and equipment. Sometimes we buy on our own. At others we buy as part of a purchasing group, when the equipment is less time-critical or we can use plant that conforms to a standard specification.

5.7 We test our market-driven and internal costs by benchmarking. We benchmark our teams and sections against each other within the company. We benchmark our company against:

- Other DNOs
- Other asset, engineering and service companies in the UK
- International energy companies
- International engineering and asset management companies

5.8 Whilst cost benchmarking is important, it tends to lose some of its meaning unless it is also benchmarked against outputs. We have been leading the industry in the development of tools to allow efficiency to be assessed across DNOs using unit costs linked to outputs.

5.9 We commissioned a number of external benchmarking reports to help us identify areas where we can become even better (see Annex 5).

5.10 We asked Mott MacDonald to benchmark our entire business against the competitive, unregulated asset management industry. This provided some major insights, particularly in the proportionality of our organisation (customer-facing versus support) and optimising our standby and response teams. As a result, we are now examining best practice in emergency response organisations like the fire and ambulance services and identifying how we can implement this within our company.

5.11 We asked Gartner to benchmark our IT services in terms of scope, service level and cost. Their findings were generally favourable and ratified our existing plans to streamline non-operational IT services and reduce resultant support and IT life-cycle costs.

5.12 We asked KPMG to analyse our fixed cost base and compare this to "group" organisations, where fixed costs appear proportionately lower because they are spread across a wider range of operational companies. Their analysis suggests that the fixed costs of a "double" company should be around 30% higher than those of a "single" company. We have used this ratio to test the proportionality of our fixed cost base to other DNO groups and satisfy ourselves that our fixed costs are both efficient and justified.

5.13 We have independently developed our Control Room systems over the years to add custom functionality which has not been available in the wider market. This has supported our automation, restoration and monitoring performance improvements. We recognise that, over time, "off-the-shelf" solutions have caught up and we are satisfied that as we prepare to renew our Control Room systems an "off-the-shelf" solution offers better long-term value for our customers and us. We have carried out a number of national and international reference site visits to help us make the right choice.

5.14 We have used all this independent analysis alongside a number of regulatory comparative efficiency assessment tools to test and challenge every aspect of our cost base. We are confident that our costs are among the most competitive in our industry and, when assessed against the Outputs we will deliver, offer outstanding value to our customers.

5.15 We took our July 2013 plan seriously and undertook a lot of work to ensure that it was efficient and included analysis demonstrating its efficiency. Ofgem's analysis showed us to be upper quartile based on its totex analysis but to be outside of the upper quartile in its bottom up assessment. We were very disappointed that our plan was not assessed by Ofgem to be efficient. Our view of the efficiency of our plan at totex level was very similar to Ofgem's ultimate view. This shows that our clear focus on managing the total costs that we ask customers to pay for was successful.

5.16 We have undertaken a detailed review of Ofgem's cost assessment approach. Within Ofgem's bottom up analysis, it is clear that inappropriate analysis of a small number of activities has had a disproportionate effect on the assessed efficiency of our plan. We recommend that Ofgem makes a small number of important changes to its cost assessment approach for slow track companies to address these material issues.

5.17 More details of our analysis and recommendations can be found in Annex 14.

5.18 We have reviewed our plan in great detail in preparation for resubmission and have undertaken substantial analysis to assure ourselves that our revised plan represents and efficient a well justified proposition for customers to fund. We have removed costs where there is evidence that the costs included in our July 2013 plan were inefficient and have removed more than £37 million costs from our plan as a result. Our analysis shows that we can expect our revised plan to be assessed to be upper quartile across all activity areas and to be comfortably within overall upper quartile.

5.19 We are confident that our resubmitted plan represents an efficient proposition for our customers in the North West to fund.

Developing Efficient Volumes

Our customers want a safe, reliable network and that is what we provide. There are a number of different ways to do this and we seek to use the optimum mix of repair, replacement and reinforcement to deliver it.

5.20 We are generally guided by our asset management strategies and engineering expertise however we regularly test these with other techniques (eg Cost Benefit Analysis (CBA)) to ensure they are driving the right mix and level of work.

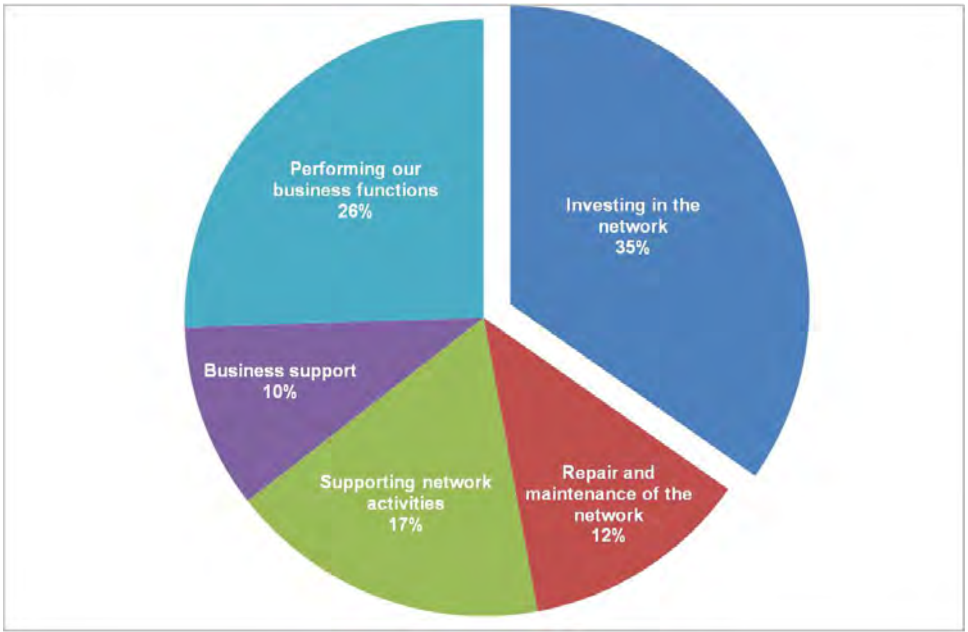
5.21 We asked PB Power to benchmark our initial volume plans and assess them against our network reliability objectives. Their review identified some areas where alternative approaches and solutions would deliver similar or better outputs but with reduced levels of work.

5.22 Consequently, we implemented a number of changes which resulted in a volume-driven cost reduction of £53 million across our asset replacement and reinforcement programmes. We verified our new plans by asking PB Power to repeat their initial exercise and provide an opinion on the efficiency of the revised programme. They concluded that we had acted on their recommendations and our proposed volumes were robust. We are confident, therefore, that the volumes and mix of work which underpin our business plan commitments are efficient (see Annex 17).

5.23 We develop volumes from a bottom-up analysis of asset and network condition and performance, CBRM, policy and standards and national guidelines combined with stakeholder engagement on priorities and willingness to pay.

Investing in the Network

Our largest single spend category (35% of our total expenditure) is investing in our network.

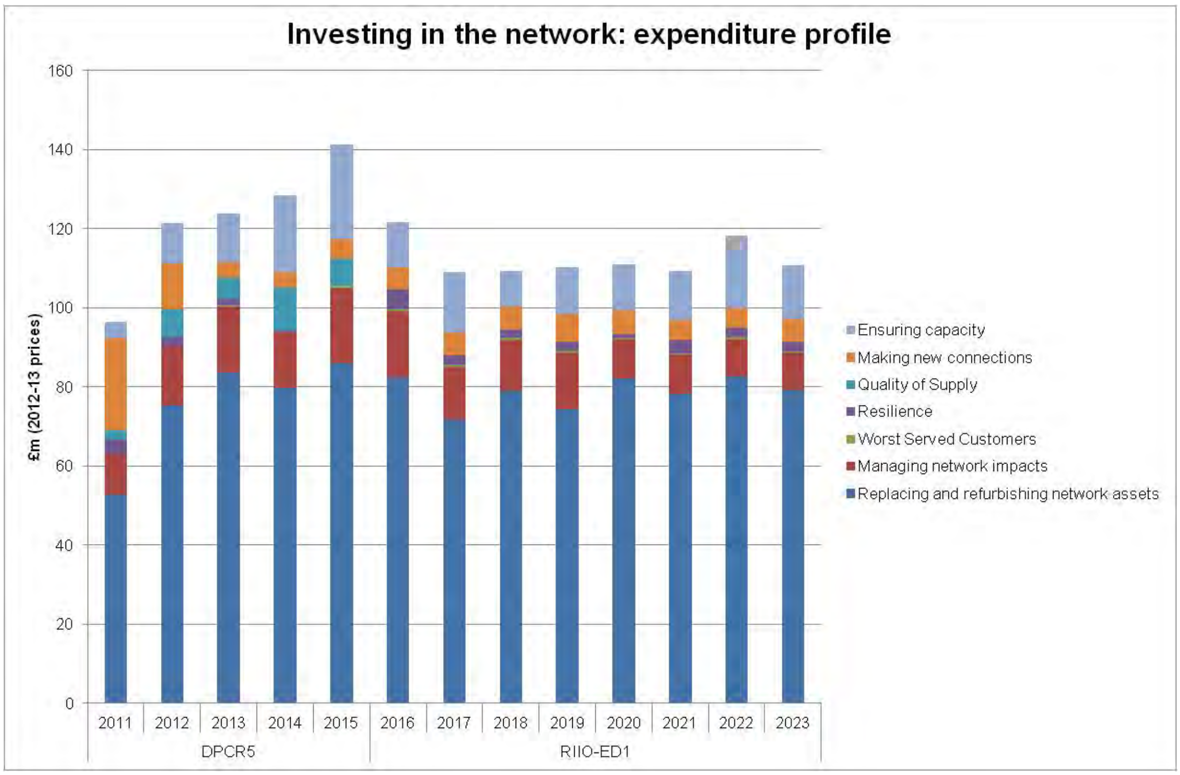


5.24 This covers:

- Replacement and refurbishment of existing assets to maintain network performance and safety
- Management of our safety and environmental impacts
- Improving network performance
- Connecting new customers to our network
- Upgrading the network to increase its capacity

Our stakeholders are prepared to pay £2.27 more on their bill to allow us to make further improvements to the network.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Replacing and refurbishing network assets	377.4	75.5	629.5	78.7	4.3%
Managing network impacts	74.7	14.9	96.1	12.0	-19.6%
Worst Served Customers	1.3	0.3	3.4	0.4	66.1%
Resilience	7.8	1.6	20.7	2.6	65.2%
Quality of Supply	32.8	6.6	-	-	-100.0%
Making new connections	47.5	9.5	46.2	5.8	-39.2%
Ensuring capacity	69.8	14.0	103.4	12.9	-7.3%
Total	**611.2**	**122.2**	**899.2**	**112.4**	**-8.0%**



Replacing and refurbishing network assets

Replacing and refurbishing existing network assets is the largest single component of our network expenditure. Our network comprises a variety of asset types, each of which performs a specific function in the electricity distribution process.

5.25 As these assets age, their probability of failure generally increases and they must eventually be refurbished or replaced. For a small number of asset types it is more efficient to replace them only after they fail but in most cases it is best to carry out the replacement or refurbishment before failure occurs. This requires a careful balance between investing too early (potentially foregoing some remaining useful operating life) and too late (running an unacceptable level of failure with consequential impacts on network performance, safety and future costs).

5.26 We improve network reliability through a combination of automation and operational response. This improvement depends on maintaining a stable base in underlying network performance. Our investment in asset replacement and refurbishment provides this stable base. We have a number of options in the way we combine replacement and refurbishment and we use a number of techniques and models to help us get the balance right.

5.27 We develop pricing from a bottom-up analysis of actuals, forecasting future frontier shift (efficiency improvements in our business) and Real Price Effects (RPE). RPE is a measure of the actual cost increases we experience relative to Retail Price Index (RPI) inflation. In RIIO-ED1 we expect the RPE impact to be £82.6 million. We have fully absorbed this cost impact through cost efficiencies elsewhere in our business plan.

5.28 Where we have multiple intervention options, we combine our asset management practices with CBA to determine the most cost effective interventions.

5.29 We will spend £629.5 million over RIIO-ED1 on investment in our network. This is broadly similar to our annual investment rate in DPCR5, although the mix of work has changed substantially. The investment plans by a major asset group are as follows:

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Services	15.4	3.1	23.3	2.9	-5.7%
Rising lateral mains	3.0	0.6	14.5	1.8	198.4%
Woodpole lines	47.8	9.6	38.2	4.8	-50.0%
Steel towers	39.4	7.9	80.1	10.0	27.1%
LV & HV cables	25.1	5.0	43.5	5.4	8.2%
EHV & 132kV cables	46.1	9.2	47.2	5.9	-35.9%
LV & HV plant	49.9	10.0	132.6	16.6	65.9%
EHV & 132kV plant	52.2	10.4	108.8	13.6	30.4%
Civil structures	28.0	5.6	75.8	9.5	69.4%
Operational IT	31.7	6.3	65.6	8.2	29.3%
High value projects	38.8	7.8	-	-	n/a
Total	**377.4**	**75.5**	**629.5**	**78.7**	**4.3%**

Impact on network risk

Our Risk Index approach lets us assess the impact of each replacement on network risk on a common scale. Overall our target is to keep network risk within 3% of its 2015 position.

5.30 To achieve this, we are forecasting improvements from each major asset group for which we have risk index forecasts. Further details can be found in Annex 2B – CBRM Detailed results. The following sections describe the investment required to meet this target.

5.31 Refurbishment can provide a substantial majority of the benefits of replacement for a fraction of the cost. We expect to save around £50 million from refurbishing rather than replacing in RIIO-ED1.

Detailed expenditure plans

Services

5.32 Our underground services which carry electricity from our network to our customers are not managed using CBRM because their large number and underground location make it difficult to gather reliable condition data.

5.33 We handle faults reactively and our forecast is based on an extrapolation of historic fault rates and unit costs to repair them with an increment for the replacement of obsolete cable types to ensure that all replacement services are capable of supporting low carbon technology adoption. We will spend £23.3 million on underground services during RIIO-ED1, a 5.7% annual reduction compared to DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Services	15.4	3.1	23.3	2.9	-5.7%

Rising and lateral mains

5.34 These are the services within multi-occupancy dwellings such as maisonettes and high-rise flats. They comprise mains wiring to a series of meters within the building. Following national debates over the ownership of these installations in DPCR4, we established a programme of inspection in DPCR5 and have commenced replacement where necessary.

5.35 Over the course of RIIO-ED1, we will spend £14.5 million on replacing these services, an increase of 198.4% on our DPCR5 programme due to the recent instigation of this work.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Rising lateral mains	3.0	0.6	14.5	1.8	198.4%

Woodpole lines

5.36 Parts of our overhead network are carried by wooden poles, many of which date from the 1950s and 1960s.

5.37 We are completing a major programme of overhead line compliance work in DPCR5 which is replacing a large number of the poorest condition poles. As a result, our forecast for woodpoles is a reduction in the replacement rate compared to DPCR5.

5.38 We will use a defect management regime to replace specific poles rather than undertaking widespread rebuilds or cyclic refurbishment. We will spend £38.2 million on woodpoles over the course of RIIO-ED1, a 50% decrease on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Woodpole lines	47.8	9.6	38.2	4.8	-50.0%

Steel towers

5.39 Steel towers (pylons) support the majority of our above ground 33kV and 132kV circuits. They are made up of a number of components and as such are much easier to refurbish than woodpoles (eg through selectively replacing deteriorated steel members) but more difficult to replace in their entirety. As such, our management regime for these assets is generally one of on-going refurbishment and painting to minimise the need to replace whole towers.

5.40 We will spend £80.1 million on refurbishing and replacing steel towers over RIIO-ED1, a 27.1% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Steel towers	39.4	7.9	80.1	10.0	27.1%

5.41 The increase is the result of the completion of our full tower condition survey in 2012. This condition data was used in our CBRM model to produce our forecast.

LV and HV cables

5.42 Underground LV and HV cables form the bulk of the distribution network by length and value. The very oldest installations date back to the early 20th century and they are intrinsically reliable. Where issues do occur, they are often localised based on local environmental factors, disturbance or issues specific to particular cable types and/or construction methods.

5.43 Our plans are based on the selective overlay of cables exhibiting high fault rates. As they are underground and rarely disturbed, it is very difficult to collect condition information on these cables and equally difficult to predict where future faults will occur.

5.44 Over the course of RIIO-ED1 we will spend £43.5 million on LV and HV cables, an 8.2% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
LV & HV cables	25.1	5.0	43.5	5.4	8.2%

5.45 As the majority of our spending on these assets is fault related (and we expect to maintain a stable fault rate) our volumes will remain steady. The reduction in total spending is the result of reduced unit costs due to delivery efficiencies.

EHV and 132kV cables

5.46 Our higher voltage cables form the majority of our bulk distribution network. Most of these cables are extremely reliable and replacing them is a highly disruptive activity.

5.47 More recently installed cables are of solid construction which require no on-going maintenance, however we have significant numbers of earlier cable types where insulation is provided by pressurised gas or oil. These are electrically very reliable but they bring environmental, service and operational risks. We have to inspect and maintain the tanks, pumps and other ancillary equipment that are required to operate these cables.

5.48 In RIIO-ED1 we will spend £47.2 million on these cables, a 35.9% reduction on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
EHV & 132kV cables	46.1	9.2	47.2	5.9	-35.9%

5.49 Based on stakeholder feedback and our environmental obligations, we have set a target of reducing oil lost from these cables by 3200 litres a year by 2023. Part of our response to this is a planned programme of cable replacement which we started in DPCR5 and will take us 30 years to complete. Together with on-going refurbishment activities, CBA analysis suggests that this is the best value approach to managing these assets over the medium term (see Annex 3). As a result, we plan to replace 57km of these cables with modern solid equivalents in RIIO-ED1. This programme is based on replacing those cables in the highest risk settings (eg in the vicinity of a watercourse) first.

5.50 The 35.9% decrease in spending is a result of the adoption of the efficient 30-year cable replacement plan.

LV and HV plant

5.51 These assets are the ones that transform the voltages we use for distribution into standard mains voltage and route electricity through our LV and HV network. These assets are often located in residential areas, under pavements and on street corners close to the customers they serve.

5.52 Over the course of RIIO-ED1 we will spend £132.6 million on LV and HV plant which is a 65.9% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
LV & HV plant	49.9	10.0	132.6	16.6	65.9%

5.53 Based on the current health of the network and our projections of future risk, we need to increase the replacement rates for these assets to prevent a significant increase in failures and replacement costs in the future.

5.54 One model of LV switchgear contains a fuse board which presents a safety hazard for our employees. There are several thousand of these on our network. Where possible, we are refurbishing them but a large number of replacements are unavoidable and this contributes to the increase in volumes and expenditure.

EHV and 132kV plant

5.55 Plant consists of the transformers used to transform electricity between voltages and the switchgear used to operate them. These are our largest single assets and are located on major substation sites around the region.

5.56 Some of the largest sites are shared with National Grid and occasionally other DNOs. Where this is the case, we co-ordinate with these other operators to ensure we have efficient work programmes.

5.57 As these assets are so fundamental to the delivery of our service and take so long to replace if damaged, they are duplicated so that the backup transformer can take the load in the event of a fault. We inspect and maintain these assets regularly and use the condition information to carefully judge the best time to replace or refurbish each unit. Over the course of RIIO-ED1, we will spend £108.8 million on replacing and refurbishing EHV & 132kV plant which is a 30.4% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
EHV & 132kV plant	52.2	10.4	108.8	13.6	30.4%

5.58 These assets are getting older; inevitably older assets require increasing amounts of investment. We use CBRM to ensure replacement is kept to a minimum, but the technique can not fully mitigate the necessary increase brought about by age.

5.59 We have included programmes of plant refurbishment in the forecast, including 33kV, 11kV & 6.6kV circuit breakers, where we have developed innovative options for the installation of retrofit breakers. This assumption has allowed us to reduce the volume of units planned for full replacement.

5.60 Our forecast also includes refurbishment of over 100 Grid and Primary transformers, using the in-situ oil regeneration technique we developed in partnership with the University of Manchester.

Civil structures

5.61 The civil structures we look after include buildings, concrete plinths, compound fences and other structures. These play a vital role in protecting our electrical equipment. We need to invest to ensure that the civil works are fit for their intended purpose and that they meet all relevant safety standards.

5.62 We will spend £75.8 million on civil work over the RIIO-ED1 period, which is a 69.4% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Civil structures	28.0	5.6	75.8	9.5	69.4%

5.63 The increased programme size is driven by:

- Additional plant volumes
- New major programmes on cable structures (pits, tunnels and bridges)
- An increase in Grid and Primary works (eg substation dehumidifier upgrades)

5.64 The volumes of civil work driven by plant asset replacement have been reduced following implementation of standard solutions, which allow more in-situ plant replacement and refurbishment.

Operational IT and Telecoms

5.65 Operational IT and Telecoms assets are those used in the real-time control, monitoring, management and restoration of our network. The infrastructure includes the Remote Terminal Units (RTU) connected directly to the primary electrical plant, the control room real-time systems and the communications infrastructure that links the RTU population to the control room systems.

5.66 We have historically developed and maintained our own custom Network Management System (NMS) software. This has provided many benefits, particularly in relation to network automation, which were not available from 'off-the-shelf' systems. We have recently completed an evaluation of future requirements based on developments in the software market and analysis of the requirements of a future smart network (including smart meter data integration).

5.67 We concluded that continuing to develop bespoke real time systems in house would incur significant additional cost and present increasing risk to our business. We also conducted a number of expert reviews of our Operational IT strategy, focused on fit-for-purpose current and future functionality, simplification of infrastructure complexity and reduction in total cost of ownership.

5.68 We conducted a number of reference client engagements with both British DNOs and with US electricity and gas companies. We found that internationally, the maturity of the smart grid roadmap and integration to Advanced Meter Infrastructure (AMI) is generally more advanced than in the UK. As a consequence most of the real time systems vendors with implementations across Europe and the US have already started to move their core systems along the smart future roadmap and some have mature offerings in demand side management, contract management and advanced meter infrastructure.

5.69 The recommendations from the reviews and reference engagements led to the creation of a strategy for Operational IT and Telecoms investment that is underpinned by a scalable and reliable strategic platform, which allows the future deployment of new smart grid technologies. This strategy relies on improving data quality, data management, and implementation of a commercial off-the-shelf NMS platform. Advanced analytics and smart functionality will be developed on top of this core platform.

5.70 The Operational IT transformation programme will create benefits by integrating smart meter data much earlier than would otherwise be the case (see Annexes 18 and 28).

5.71 As part of the transformation programme, we will also refresh the Operational IT communications equipment and RTU population to maintain and improve network performance as smart technology is progressively implemented in the UK.

5.72 We will spend £65.6 million on Operational IT over RIIO-ED1, a 29.3% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Operational IT	31.7	6.3	65.6	8.2	29.3%

5.73 Costs are driven by the replacement of our network management system which started in DPCR5, implementation of smart grid capabilities such as contract management, energy management and distributed generation management. Through refreshing and upgrading our operational IT estate to maintain current performance and to support the increase in automation we will deliver network performance improvements at a lower overall cost.

Managing network impacts

5.74 We need to ensure that we operate a safe and environmentally sound network. We invest in these areas to ensure we follow our safety and environmental principles, comply with all applicable legislation, and deliver our safety and environmental Outputs. We also sometimes have to move our assets where we no longer have the right to maintain them on land which does not belong to us.

5.75 Over the RIIO-ED1 period we will spend £96.1 million which is a 19.6% decrease on an annual basis from DPCR5. This decrease is driven by the completion of our ESQCR programme.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Maintaining safe network	14.1	2.8	39.7	5.0	75.9%
Reducing environmental impacts	2.4	0.5	6.4	0.8	67.4%
Reducing electrical losses	0.7	0.1	10.4	1.3	857.5%
ESQCR compliance	34.4	6.9	3.3	0.4	-94.0%
Diverting our equipment	18.0	3.6	27.2	3.4	-5.6%
Undergrounding	5.2	1.0	9.1	1.1	9.7%
Total	**74.7**	**14.9**	**96.1**	**12.0**	**-19.6%**

Maintaining a safe network

Safety is our number one priority and we invest to ensure the safety of our people, our contractors and the public.

5.76 Many of our assets were installed several decades ago. The materials, tools and equipment available today have significantly improved. Consequently we are undertaking a range of investment programmes on our assets to ensure they are fully compliant with modern standards and legislation.

5.77 These programmes comprise:

- Managing the risk from asbestos at substations
- Installing safe climbing equipment on our steel towers and key items of plant
- Increasing the security of substation sites to prevent third party access

5.78 We have made good progress on remediation of asbestos at our indoor substations and have planned for a programme of remediation for our outdoor substations. We have identified overhead line assets where specific legal and safety issues exist, for example high earth resistance values and the replacement of ceramic surge arresters.

5.79 We will spend £39.7 million on these safety programmes over RIIO-ED1, a 75.9% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Maintaining safe network	14.1	2.8	39.7	5.0	75.9%

5.80 A significant part of the increase is driven by our response to an increase in metal theft incidents over the last few years. This is projected to continue as metal prices rise and we need to upgrade substation security measures to address this.

Reducing environmental impacts

5.81 We have included volumes in our plan to continue to mitigate a range of environmental impacts including noise from our transformers, oil loss from our equipment and cleaning up contaminated land.

5.82 The total spend on reducing environmental impacts over RIIO-ED1 will be £6.4 million, a 67.4% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Reducing environmental impacts	2.4	0.5	6.4	0.8	67.4%

5.83 The increase is a result of greater volumes of remediation work on oil-contaminated land and work on containment systems to prevent contamination from sites leaking into the surrounding environment.

Reducing electrical losses

5.84 Electrical energy is lost in the process of distribution. Equipment that leads to lower losses is available but this is generally more expensive than our existing equipment.

5.85 We used CBA to identify where installation of low loss equipment, particularly transformers, would deliver long-term cost and environmental benefit for our customers. Consequently we have included £10.4 million in our plans to replace 652 installations over the first four years of RIIO-ED1. This is expected to produce savings of 10,972 MWh a year, the equivalent of removing 5,709 tonnes a year of CO_2 from UK emissions (see Annex 19).

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Reducing electrical losses	0.7	0.1	10.4	1.3	857.5%

ESQCR compliance

5.86 Our work to ensure our circuits meet the requirements of the Electricity Safety, Quality and Continuity Regulations (ESQCR) will be complete in 2016.

5.87 We forecast that we will need to continue our current programme of rectification into 2016. No specific forecast has been made for a proactive programme beyond this point. If isolated instances are identified in the future, whether by customer referral or in the course of routine inspection, we will respond to them as Troublecall (operational fault remediation) incidents if urgent, or otherwise as part of our planned replacement and refurbishment work.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO.ED1 Annual Average	% Change
ESQCR compliance	34.4	6.9	3.3	0.4	-94.0%

Diverting our equipment

5.88 Diversion costs are incurred where we have to move our assets because the current route or site becomes unavailable, for example through the termination of the legal rights to locate our equipment, or because of the construction of a new highway.

5.89 Every year we deal with a number of claims from property owners relating to the reduction in value or productivity of their property and/or land as a consequence of our assets. In these cases, we often pay the grantor a sum to convert our access right from a terminable wayleave to an easement, which gives us permanent right to remain. This is done where it is cheaper than moving the assets involved and where there is a continued requirement for the assets.

5.90 In some cases, it is cheaper to move or divert the assets. This may also be the case where the landowner or developer wishes to develop a new site and serves us with a termination notice.

5.91 In developing the forecast we have looked at recent trends and concluded that the rate of terminations has stabilised. We have also considered the effects of the New Roads and Street Works Act (NRSWA) and of large infrastructure projects in our region. For example with the Network Rail Electrification Project we have made a provision for the NRSWA diversions within roads and bridges in our submission, but we have made no provision for overhead line diversions, as we expect these to be recharged to Network Rail. Combining all of these factors, we expect the volume of diversions work to remain steady over the course of RIIO-ED1.

5.92 Where diversions are required, at the specific request of third-parties, we will seek to charge them where appropriate. We have forecast a decrease of 5.6% in diversion expenditure, driven by efficiency savings on a constant volume of work. We will spend £27.2 million in RIIO-ED1.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Diverting our equipment	18.0	3.6	27.2	3.4	-5.6%

Undergrounding

5.93 We will invest £1.1 million per annum throughout RIIO-ED1. The detailed selection of areas for undergrounding will continue to be guided by our regional partners and stakeholders. Our investment will allow us to underground approximately 80km of existing overhead lines by 2023.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Undergrounding	5.2	1.0	9.1	1.1	9.7%

Worst Served Customers

5.94 We are planning to ensure that no customers receive a service that would qualify them as 'worst-served' by 2023. Worst Served Customers (WSC) are those who experience 12 or more interruptions due to faults on the high voltage network, over a three-year period.

5.95 It is our firm view that as our customers' use of and dependence on electricity increases, particularly as a result of the decarbonisation of transport, heating and generation, extremities of performance will become increasingly unacceptable to them.

5.96 We already have the lowest percentage of worst served customers of any DNO outside of London and will reduce this to zero by the end of RIIO-ED1.

5.97 The investment is a package of measures tailored to the requirements of the network in the vicinity of the relevant customers. It includes a mix of overhead line rebuilds as well as additional protection and remote control facilities.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Worst Served Customers	1.3	0.3	3.4	0.4	66.1%

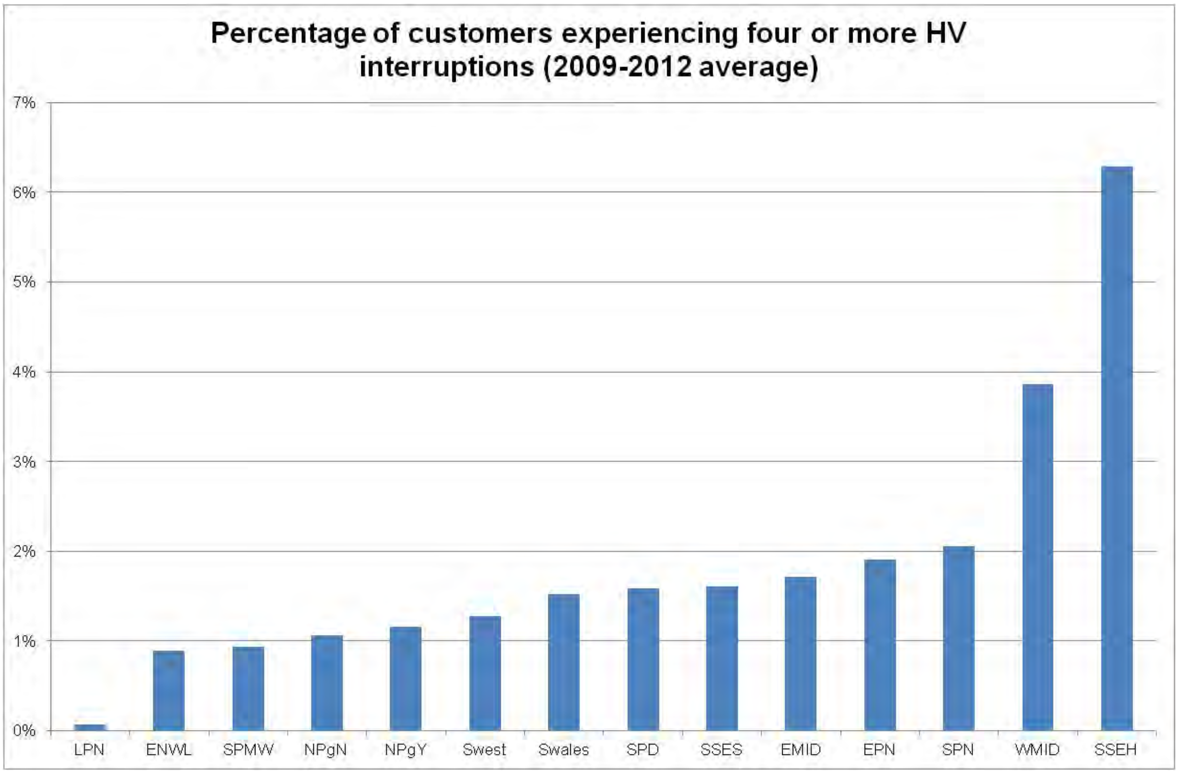
5.98 We will spend £3.4 million in RIIO-ED1 on our WSC programme.

Improving resilience to extreme events

5.99 It is important that our network is able to survive and recover from extreme events such as flooding, terrorist attack, and a total shutdown of the National Grid.

5.100 We have analysed the high-risk points on our assets and routes where multiple circuits can be affected by a single incident. This study identified seven 132kV and thirteen EHV sites where the risk was significant. Further work on potential mitigation measures identified that three 132kV sites and three EHV sites require network reinforcement or diversion to appropriately manage the risk.

One very high priority site is being addressed in DPCR5. The other five sites are currently included in our RIIO-ED1 forecast. The expenditure associated with this work is included in our expenditure forecasts for civil work and cables.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Flooding	7.8	1.6	10.7	1.3	-14.4%
Critical National Infrastructure	-	-	2.6	0.3	n/a
Black Start	-	-	7.4	0.9	n/a
Total	**7.8**	**1.6**	**20.7**	**2.6**	**65.2%**

Flooding

5.101 Protecting our substations from severe flooding is essential to maintain a resilient network. We have made excellent progress in delivering the DPCR5 flooding programme with all 31 sites planned for DPCR5 completed by January 2014. This will ensure that 550,000 customers benefit from additional protection against interruptions due to 1-in-100-year flood.

5.102 Working with new data from the Environment Agency we have identified a further 56 sites which are also now identified as at risk of flooding. We will spend £10.7 million on protecting substations from flooding in RIIO-ED1, a 14.4% decrease on an annual basis from DPCR5.

> *Communication with the public is important – dealing with problems people need to have clear information available. Also when improvements are being made, publicise what you are doing and what the benefits will be.*
>
> ***Dave Walker, Wigan Council***

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change

Flooding	7.8	1.6	10.7	1.3	-14.4%

Critical National Infrastructure (CNI)

5.103 CNI sites are those deemed most critical to the national interest. As a result of our work with the security services, we have agreed that two sites should be classified as CNI and protected during RIIO-ED1. In addition to the upgrading investment, we need to maintain a dedicated 24-hour monitoring function for these sites. The most cost-effective solution is outsourcing to a specialist vendor.

5.104 We will spend £2.6 million on our CNI programme over RIIO-ED1.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Critical National Infrastructure	-	-	2.6	0.3	n/a

Black Start

5.105 When an entire region loses electrical power, the generation, transmission, and distribution networks must be re-energised in a precise sequence known as Black Start. To comply with these requirements, we need to ensure that our major substations have enough backup battery capacity to be able to switch back on when required.

5.106 When batteries come up for replacement at these sites, we will upgrade their capacity to 72 hours in line with guidance from DECC. This will cost £7.4 million over the RIIO-ED1 period.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Black Start	-	-	7.4	0.9	n/a

Quality of Supply (QoS)

5.107 Over the last few years we have invested significantly to reduce the impact of power cuts on customers by improving the ability of the network to detect faults and restore supplies. This has produced real benefits for customers in terms of improved supply availability.

5.108 Customers tell us that this remains their top priority so we expect to continue to invest in such programmes as we seek to achieve our goal of a 20% reduction in Customer Interruptions and Customer Minutes Lost by 2019. Much of the investment in our plan has an incidental effect on the reliability and availability of supply. We have not included funding in our plan for investment which is solely designed to improve Quality of Supply. This will be paid for through the rewards we earn for out-performing Ofgem's RIIO-ED1 performance targets.

Making new connections

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Making new connections	47.5	9.5	46.2	5.8	-39.2%

Customer connections (associated reinforcement costs)

5.109 When customers need to connect to our network we sometimes need to increase capacity to allow this to happen. Customers are sometimes asked to contribute to this cost; this income is not included in the figures above. We forecast that growth on our network will continue to be largely driven by demand from customers for new connections to new buildings.

5.110 The rate of these will be driven by a combination of population and economic growth factors. Connecting customers is a competitive market, with a number of different service providers capable of providing quotations and making new connections to our network. The 39.3% change is largely due to a change in categorisation.

Connecting Distributed Generation

5.111 The amount of local generation (also called Distributed Generation) that connects to our network is largely driven by the economic rewards for customers and developers. Many customers also want to connect renewable sources of generation to play their part in reducing their carbon impact.

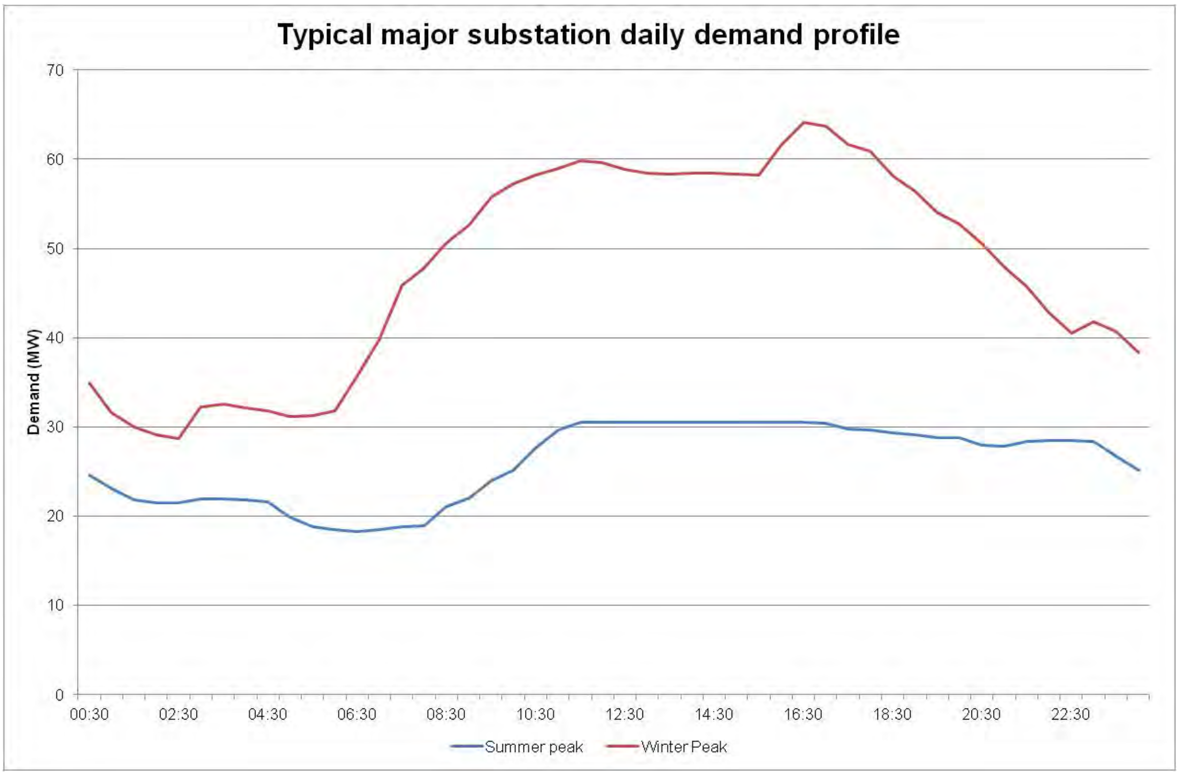
5.112 Successive government policies (such as the Feed in Tariff) have driven an increase in the amount of distributed generation connected to our network.

> *45% of customers think it is important for us to help people and schools save energy and reduce their carbon footprint.*
>
> *Engaged Consumer Panel*

Ensuring available capacity

5.113 We need to reinforce our network as the demands on it increase. These increases result from changes in population, customer consumption and connection of Distributed Generation to our network. We carry out reinforcement work by installing larger capacity transformers and/or linking parts of the network by installing new cables.

5.114 We also need to ensure that our network is capable with dealing with faults, even at times of peak demand. These peaks occur at different times of the day and year depending on the load that a particular substation is supplying, as illustrated in the graph below. Our network is designed to ensure that sufficient spare capacity is maintained to cope with incidents. Maintaining this spare capacity underpins future performance levels.



5.115 In RIIO-ED1, general reinforcement requirements will be supplemented by a need to connect increasing levels of Low Carbon Technologies (LCT) such as electric vehicles and heat pumps.

5.116 The level of LCT take-up is difficult to predict and therefore we need to take a prudent but responsible approach to reinforcement forecasting. We led work for the Smart Grid Forum to develop the Transform model that is used by all UK network operators to predict levels of LCT penetration and clustering (see Annex 20). Through Innovation Funding Incentive (IFI), Low Carbon Networks Fund (LCNF) and our own internally funded innovation (such as Demand Side Response) we are developing cost-effective solutions to allow our network to transition to and fully support the low carbon future. Our Capacity to Customers (C_2C) project aims to significantly reduce the amount of network reinforcement required to support load growth through applying smart grid technology and demand side response.

5.117 In each case we have looked carefully at non-traditional intervention options, either through innovative technical solutions, looking to exploit existing capacity, or ways of moving the peak demand which causes the investment requirement.

5.118 Spending on reinforcement is separated into general reinforcement and fault level reinforcement. Fault level reinforcement ensures that in the case of a fault, our network is able to handle it safely and without incurring damage (see Annex 21).

5.119 In forming our plans for RIIO-ED1, we have been careful to take account of the longer term context in which those plans will be delivered. Whilst we forecast that the need to reinforce our network will increase considerably in RIIO-ED2 and RIIO-ED3 we do not believe this requires or justifies the need for additional work in RIIO-ED1. The risk of creating stranded assets is still too great as we do not know where the reinforcement needs will occur (see Annex 22). In four years' time we will review this analysis as we approach the mid-point review of RIIO-ED1.

5.120 Our total reinforcement expenditure in RIIO-ED1 will be £103.4 million, a 7.4% decrease on an annual basis from DPCR5.

£m (2012-13 prices)		DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
General reinforcement	EHV and 132kV	41.7	8.3	39.3	4.9	-41.0%
	LV and HV	24.5	4.9	49.5	6.2	26.5%
Fault level reinforcement	EHV and 132kV	1.8	0.4	7.7	1.0	173.7%
	LV and HV	1.9	0.4	6.8	0.9	129.2%
	Total	**69.8**	**14.0**	**103.4**	**12.9**	**-7.4%**

5.121 The requirements for non-low-carbon related reinforcement at the higher voltages reduces in RIIO-ED1 as overall demand requirements are projected to be largely static.

5.122 However, we do foresee an increase in the investment required to both prepare for and respond to the impacts of LCTs. This is particularly pronounced towards the end of the period.

EHV and 132kV general reinforcement

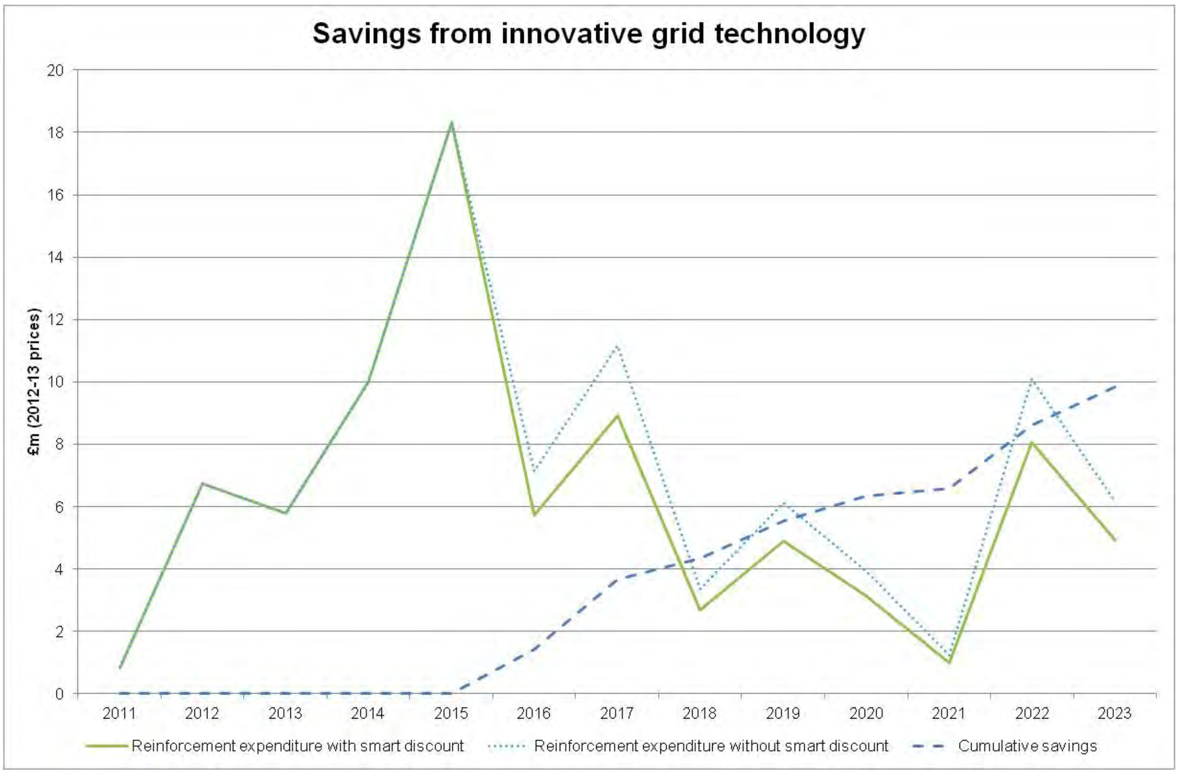
5.123 We study the current and future demand and capacity for each substation group to establish the reinforcement requirements for the higher voltages. We developed high-level reinforcement solutions taking into account overall system performance and the status of neighbouring parts of the network. The resulting projects have been costed using the efficient construction costs we expect in RIIO-ED1.

5.124 Total costs have then been discounted by 20% on the assumption that we will be able to drive additional efficiencies from our innovation programme.

5.125 We have developed an integrated reinforcement programme to ensure that any duplication of other solutions or interventions is removed and that the proposed solution meets the needs of all relevant requirements on that site or portion of network. We will competitively tender each project prior to commencement to ensure we are getting the best available prices and contract conditions.

5.126 We plan to reinforce 20 major sites during RIIO-ED1 at a cost of £39.3 million, a 41.0% decrease on an annual basis from DPCR5.

£m (2012-13 prices)		DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
General reinforcement	EHV and 132kV	41.7	8.3	39.3	4.9	-41.0%



LV and HV general reinforcement

5.127 While our EHV and 132kV reinforcement programme is made up of a small number of discrete projects, our LV and HV programme requires a larger number of smaller interventions.

5.128 The nature of the new LCT that we anticipate will be connected during RIIO-ED1 will create issues not previously seen in any significant volume on the distribution network, for example harmonic compliance and LV voltage compliance. We have included these considerations in our modelling. We have developed a software model for the whole of the LV and HV network that identifies network overloads at these voltages (see Annex 21).

5.129 A significant proportion of our services are ‘looped’ off another service and do not have a separate connection to the supplying mains cable. These services have limited capacity which will constrain the take up of LCT in the locations in which they are found. As such, we propose to address looped services that constrain the connection of LCT to the network.

5.130 The total spend on LV and HV reinforcement in RIIO-ED1 will be £49.5 million, a 26.5% increase on an annual basis from DPCR5.

£m (2012-13 prices)		DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
General reinforcement	LV and HV	24.5	4.9	49.5	6.2	26.5%

EHV and 132kV fault level reinforcement

5.131 Fault level reinforcement is undertaken so that our network can handle faults safely and without incurring damage. We calculate fault levels using network modelling. Using the 2023 peak demand forecast and associated technical assumptions, we can identify switchgear calculated to have a fault level in excess of its fault rating and flag it for replacement or reinforcement.

5.132 We will spend £7.7 million on reinforcing our EHV and 132kV networks to handle fault conditions which is a 173.7% increase on an annual basis from DPCR5.

£m (2012-13 prices)		DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Fault level reinforcement	EHV and 132kV	1.8	0.4	7.7	1.0	173.7%

LV and HV Fault Level Reinforcement

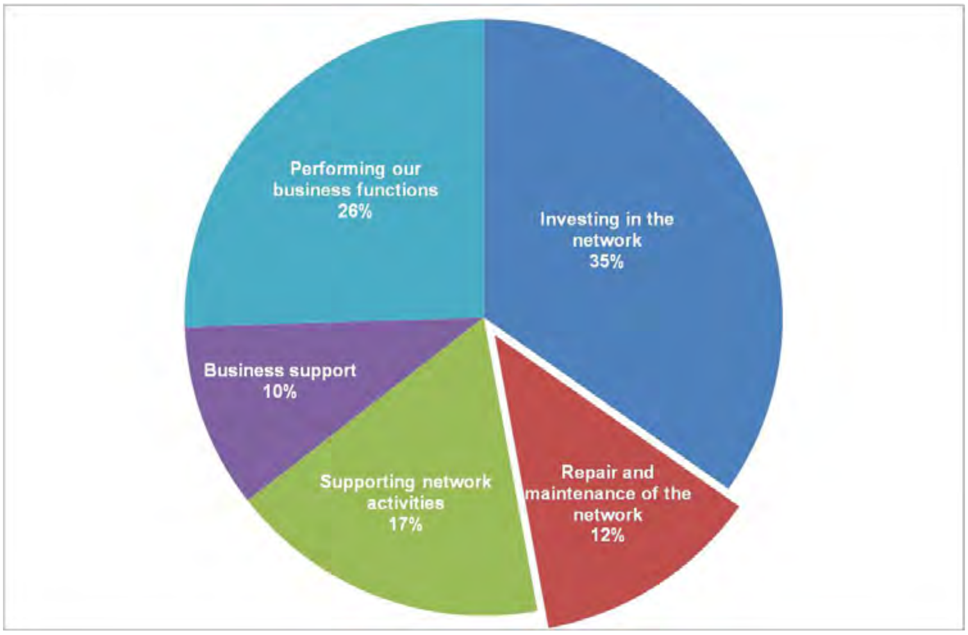
5.133 The urban areas in the North West have HV networks operating predominately at the 6.6kV level rather than the 11kV more commonly found in the rest of our area. This is a legacy from the original network installation. The fault rating of much of the switchgear associated with this network often presents a barrier to the connection of LCT. To remove this potential block we propose to remove this switchgear from our network over RIIO-ED1 and RIIO-ED2 to coincide with the expected profile of LCT adoption.

5.134 We will spend £6.8 million on this programme over RIIO-ED1, which is a 129.2% increase on an annual basis from DPCR5.

£m (2012-13 prices)		DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Fault level reinforcement	LV and HV	1.9	0.4	6.8	0.9	129.2%

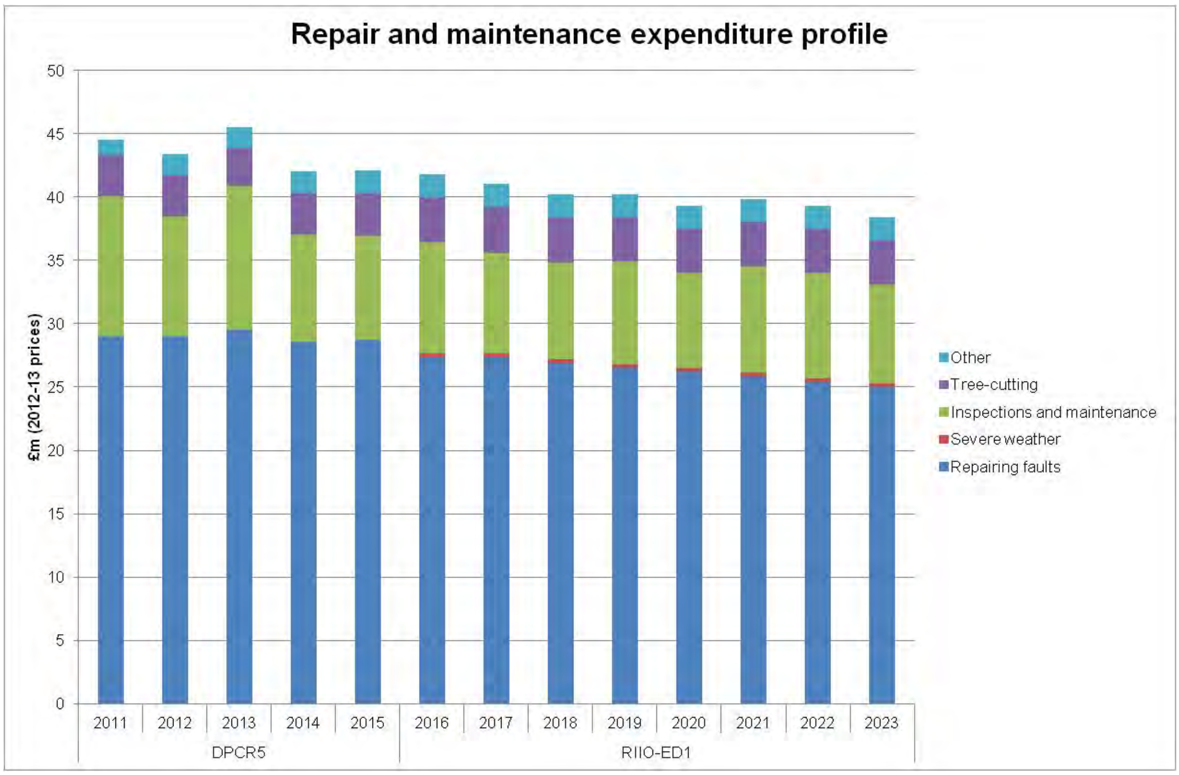
Repair and maintenance of the network

5.135 Our repair and maintenance programme keeps our network fully operational and fit-for-purpose. We invest to respond rapidly to fix faults, inspect and maintain the equipment regularly, manage the vegetation growing near our lines and run the substations on which the major plant is sited. 12% of our total expenditure is on repair and maintenance of our network.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Repairing faults	144.8	29.0	210.6	26.3	-9.1%
Severe weather	-	-	2.3	0.3	n/a
Inspections and maintenance	48.6	9.7	64.6	8.1	-16.9%
Tree-cutting	16.2	3.2	28.2	3.5	9.1%
Other	8.0	1.6	14.6	1.8	14.6%
Total	**217.5**	**43.5**	**320.2**	**40.0**	**-8.0%**

5.136 A percentage change is not applicable for severe weather as this is an allowance for events beyond our control.

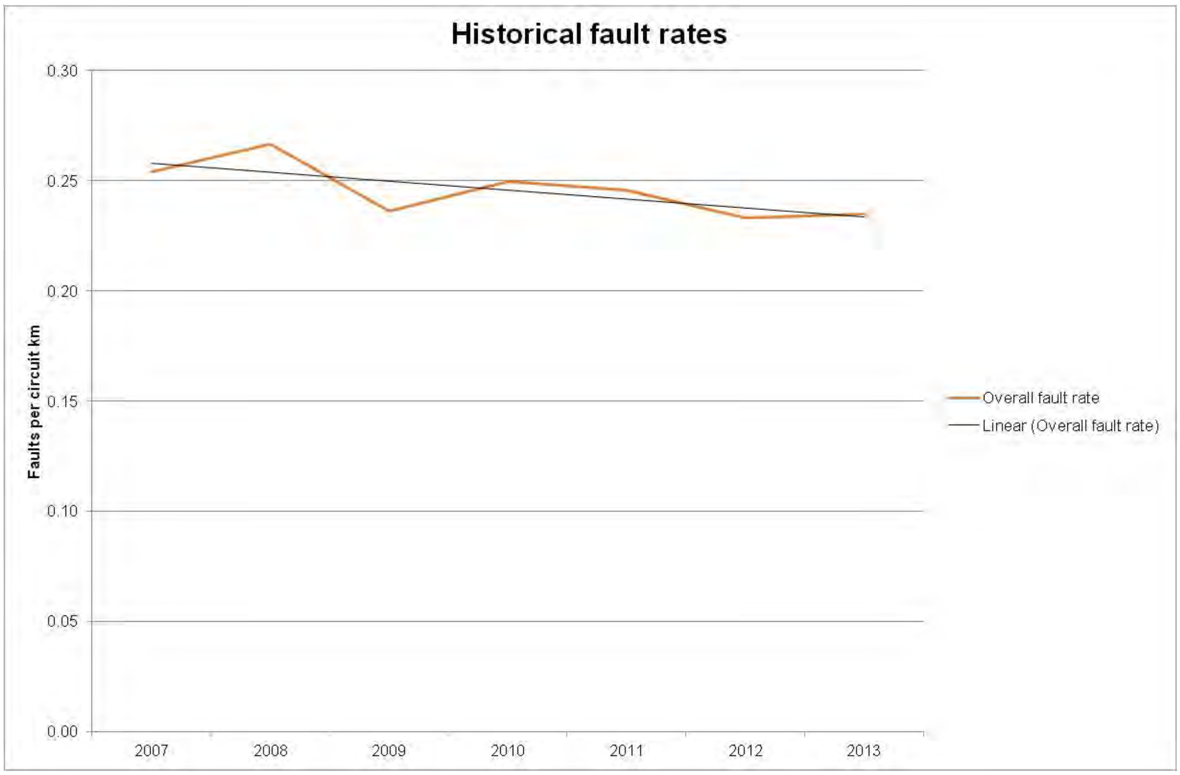


Repairing faults

5.137 When a fault occurs on our network we act to resolve it as soon as possible. Some faults can be restored from our control centre or by sending an engineer to site but 70% of faults causing an interruption to supply need to be repaired before supplies can be restored.

5.138 In a typical day we will respond to 35-40 faults resulting in an interruption to supply and 30-35 other incidents requiring a response. Responding to faults quickly is critical to achieving our goal of a 20% reduction in Customer Minutes Lost. The majority of fault response work is carried out by our own people supported, when necessary, by one of our contract partners.

Our cost forecast has been determined by assessing the historic fault volumes. Fault volumes have been stable over the last few years and our forecasts are based on the latest three-year average.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Repairing faults	144.8	29.0	210.6	26.3	-9.1%

Severe weather costs

5.139 Severe storms such as those over Christmas 2013 which affected much of the UK have a disruptive impact on our network. We experience periods of bad weather such as this in most years but occasionally have an unusually disruptive event which causes widespread damage. We refer to these as 'severe weather events' and include a provision for expenditures as a result of these severe storm damage events.

5.140 In 2005, we suffered the effect of severe floods at Carlisle, which cost £5.5 million to repair. This was our largest atypical event of the last few years and passed Ofgem's threshold to be treated as an atypical 1-in-20 year event. We have estimated our RIIO-ED1 Severe Weather costs by assuming that an event of this magnitude will occur once every 20 years and included a pro-rated cost allowance into each year's expenditure.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Severe weather	-	-	2.3	0.3	n/a

5.141 A percentage change is not applicable for severe weather as this is an allowance for events beyond our control.

Inspections and maintenance

5.142 We maintain our assets to ensure they are safe, reliable and efficient throughout their operating lives. In total, we will spend £64.6 million on Inspection and maintenance during RIIO-ED1, a 16.9% reduction on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Inspections	10.5	2.1	12.3	1.5	-26.6%
Maintenance - switchgear and transformers	18.7	3.7	31.3	3.9	4.4%
Maintenance - protection	3.6	0.7	4.0	0.5	-31.1%
Maintenance - civil works	11.6	2.3	11.1	1.4	-40.2%
Maintenance - other	4.2	0.8	5.9	0.7	-11.2%
Total	**48.6**	**9.7**	**64.6**	**8.1**	**-16.9%**

5.143 Our programme is broadly in line with DPCR5 and we will deliver it at a more efficient cost.

5.144 Maintenance of switchgear and transformers is necessary to ensure reliable and safe operation of the network. This programme will be marginally bigger in RIIO-ED1 however programme efficiencies mean we will deliver this increased volume at a lower equivalent unit cost.

5.145 Protection maintenance activities are necessary to ensure our network operates correctly under both normal and fault conditions. We maintain and inspect relays, batteries and communication links to minimise the risk of exceptional shutdowns, extensive damage to plant and risk of injury to our people and the public.

5.146 Our electrical assets are often housed on substation sites which need to be maintained properly to ensure they continue to protect the equipment they house and minimise the safety risk to the public. Planned activities on these assets (buildings, fences etc) have been forecast based on the number of assets within our asset database and policy frequencies for planned maintenance.

5.147 We also carry out a number of reactive maintenance visits, usually in response to issues found during inspection, or notified to us by customers. Our forecast is based on historic volumes; however we will deliver this work at a more efficient unit cost.

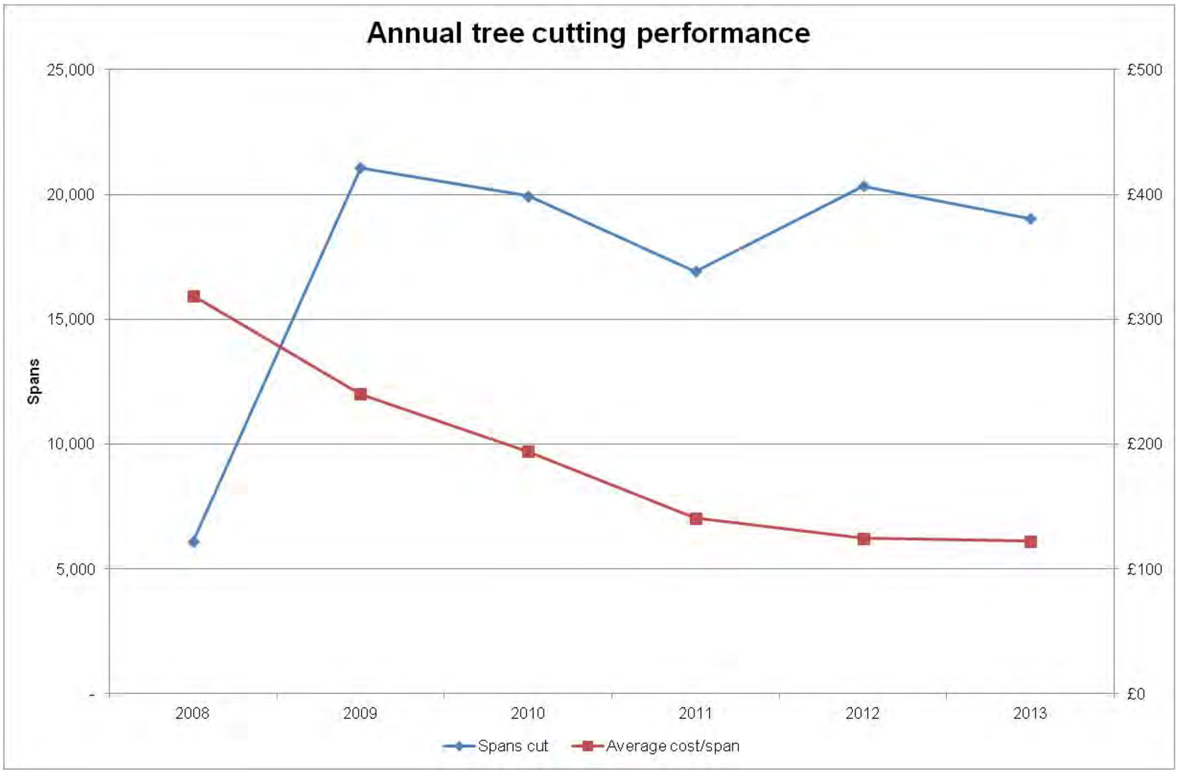
Tree cutting

5.148 Trees that grow too close to our power lines are a safety hazard and can cause power cuts. Our tree cutting activity is delivered by our own teams, who consistently deliver industry-leading levels of cost and productivity efficiency.

5.149 We have forecast a small increase in total cost despite our decreased unit costs due to additional cutting work required to comply with resilience standards[2]. These regulations require us to fell additional trees in the vicinity of our overhead lines so that trees brought down by storms cannot disrupt them. We are currently undertaking a 25-year programme to ensure we are compliant with these regulations, focussing initially on our 33kV network, which has the greatest combination of risk from tree falls and criticality to our network.

5.150 Tree cutting activity is predictable and based on a cyclical programme. As a result, expenditure is very stable over time. In RIIO-ED1, we will spend £28.2 million on tree cutting which is a 9.1% increase on an annual basis from DPCR5.

[2] ENA Engineering Technical Recommendation 132: Improving network performance under abnormal weather conditions by use of a risk based approach to vegetation management near overhead electric lines.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Tree-cutting	16.2	3.2	28.2	3.5	9.1%

Other operational costs

5.151 Substations which are live but no longer used, or where the level of utilisation is very low (eg because a factory has closed down) are potential safety hazards and are vulnerable to attack, vandalism and theft.

5.152 We are obliged by law to dismantle and remove substations when there no longer appears to be a use for them. During RIIO-ED1 we will spend £2 million on dismantling substations, a 56.6% increase over the DPCR5 period, which is driven by higher volumes.

5.153 We also have to pay for the electricity that our substations use. We use an energy procurement service, which reduces the risk to us from energy price fluctuations.

5.154 This provides a number of benefits over single supply contract procurement including:

- Allowing the purchase of energy at any time within the contract in order to take advantage of a falling market price whilst protecting against upside risk
- Avoiding the risk of purchasing on a single day for the year ahead
- Allowing multiple purchases within the contract period which spreads the risk

5.155 Our unit forecasts are based on 2012-13 consumption (13,413 MWh, equivalent to just over 4,000 houses) with a 270 MWh reduction (2%) following the deployment of smart meters which we anticipate will identify abnormally high consumption which can be reduced. Future years will see further reductions as innovations to reduce energy use within our substations are deployed across the network.

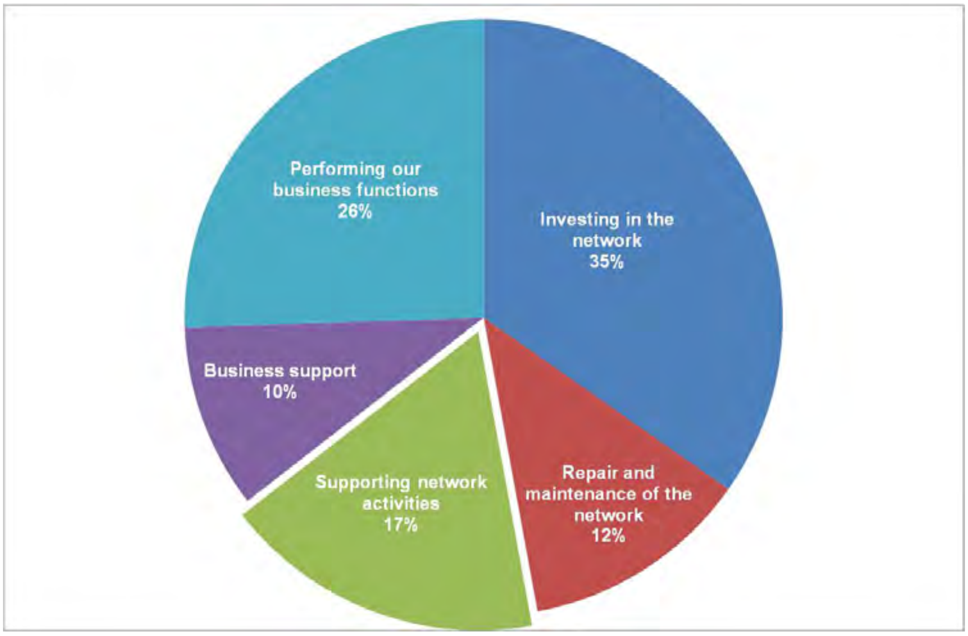
5.156 By 2023, it is anticipated that the energy consumed within substations will have been reduced by 18% through the replacement of substation appliances with more energy efficient units. However, we anticipate a 33% increase in the unit price for electricity over RIIO-ED1 which results in an increasing overall expenditure forecast.

5.157 We anticipate spending £12.6 million on substation electricity over the RIIO-ED1 period, which is a 9.8% increase on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Dismantlement	0.8	0.2	2.0	0.3	56.6%
Electricity	7.2	1.4	12.6	1.6	9.8%
Total	**8.0**	**1.6**	**14.6**	**1.8**	**14.6%**

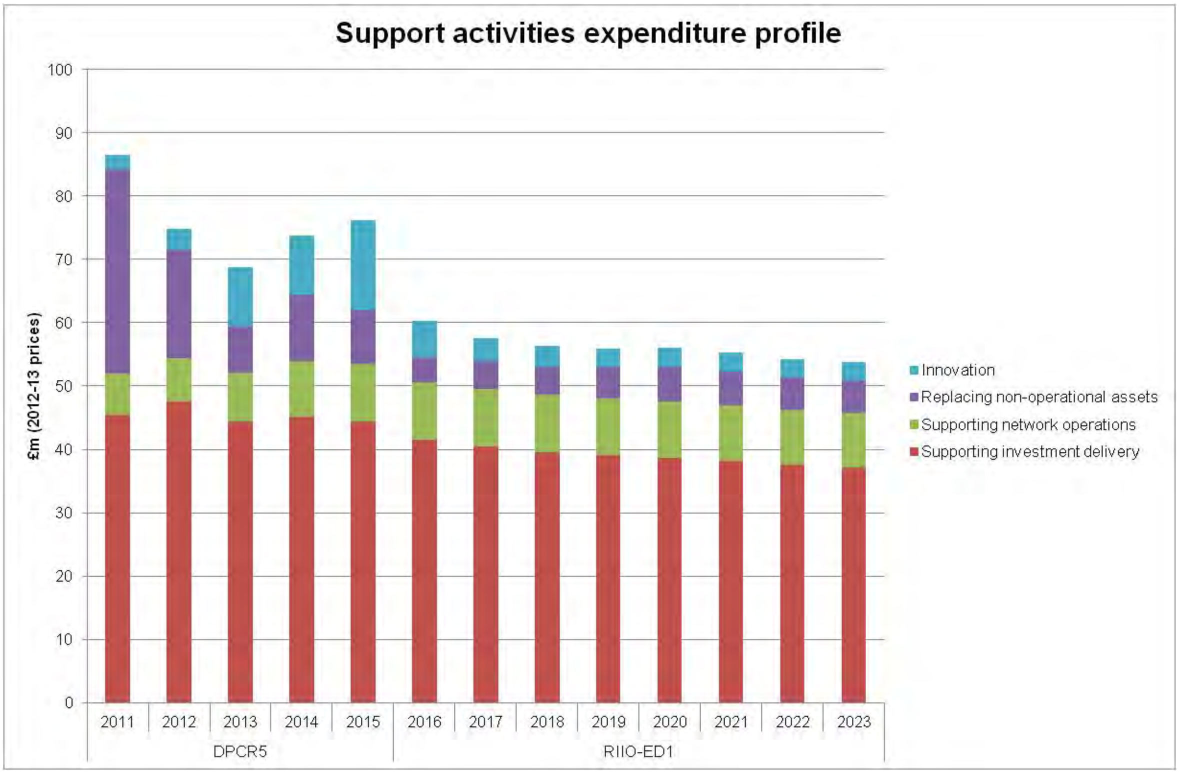
Supporting network activities

5.158 Managing our network requires considerable support activity, whether through the delivery of capital works, or providing the capability to manage day-to-day operations. We also have to plan for and manage a range of non-operational assets (such as vehicles and buildings) and also invest in innovation to continually seek out new ways of doing things. 17% of our total expenditure will be spent on supporting network activities.



5.159 We will spend 26.1% less annually on these supporting activities in RIIO-ED1 than in DPCR5 as a result of cost efficiencies.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Supporting investment delivery	227.0	45.4	312.0	39.0	-14.1%
Supporting network operations	38.7	7.7	71.4	8.9	15.3%
Replacing non-operational assets	75.7	15.1	38.6	4.8	-68.1%
Innovation	38.9	7.8	27.5	3.4	-55.8%
Total	**380.2**	**76.0**	**449.5**	**56.2**	**-26.1%**



Supporting investment delivery

5.160 We support delivery of our investment programmes with design, project management, logistics, materials and vehicles.

5.161 We will spend £312.0 million on supporting the delivery of investment in our network during RIIO-ED1, which is a 14.1% decrease on an annual basis from DPCR5. We have made significant savings in almost every category without compromising our objective of delivering a safe, reliable and resilient network for our customers.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Design and planning	46.4	9.3	60.5	7.6	-18.5%
Project management	23.3	4.7	39.1	4.9	5.0%
Work management	94.1	18.8	119.1	14.9	-20.9%
Managing materials and stock	9.7	1.9	14.3	1.8	-8.1%
Operational training	32.3	6.5	48.3	6.0	-6.7%
Vehicle operations	18.8	3.8	27.6	3.5	-8.1%
Network policy	2.4	0.5	3.1	0.4	-18.5%
Total	**227.0**	**45.4**	**312.0**	**39.0**	**-14.1%**

Design and planning

5.162 Our design and planning team is responsible for determining what work is necessary on our network, planning its delivery and carrying out the engineering design work on all our major projects.

5.163 In RIIO-ED1, we will spend £60.5 million on design and planning work, which is an 18.5% saving on the DPCR5 costs. This saving will be achieved by progressively increasing the number of standard designs we use, reducing the need for bespoke design on each capital project.

Project management

5.164 Our project management team ensures the timely and efficient delivery of our investment programme. Management of the smaller projects on our secondary network is done directly by the engineer in charge of the work. Our Grid and Primary projects, which tend to be much larger, are managed by our Major Projects Unit, which is also responsible for their design.

5.165 We will spend £39.1 million on project management over the course of RIIO-ED1, which is a similar level to DPCR5.

Work management

5.166 Work management is a very broad category that includes all the activity required to plan and efficiently deliver investment on our network. It ranges from strategic planning of the programme through the efficient co-ordination and scheduling of resources between supply restoration, repair, maintenance and planned capital programme work and the subsequent management, monitoring and reporting of delivery against the plan.

5.167 It includes managing permissions for working in the highway and the costs of the permits, dealing with wayleaves and planning consents and the annual costs we incur to secure them, customer liaison and response to enquiries, providing quotations to connections customers and important health and safety services.

5.168 We have rationalised our support model during DPCR5 to improve efficiency, breadth of support and flexibility to respond to changes in workload across the business. Some work management costs are now allocated to 'Supporting Network Operations'. As a result we have been able to reduce our work management expenditure by 20.9% to £119.1 million.

Managing materials and stock

5.169 We operate a stores system to manage the materials required on our network.

5.170 We use an external logistics provider with an offsite storage facility, together with local stores in depots supported by a number of satellite stores. Materials that are distributed by our provider are purchased by us through framework agreements with suppliers or are purchased by Framework Contractors through the same procurement arrangements. Careful stock control and liaison with our policy team ensures that we minimise the stock holdings but always have the right items in stock when required. This arrangement is competitively tendered every five years to ensure we continue to get the best rates.

5.171 We have recently completed a tender exercise; TVS Supply Chain Solutions will replace our current supplier, CEVA Logistics, from 1 April 2014.

5.172 Our spending on stores will decrease by 8.1% to a total of £14.3 million over RIIO-ED1. This cost reduction is made possible by improved logistics and inventory management policies.

Operational training

5.173 It is critical that the staff who work on our network are appropriately trained and equipped to work safely and efficiently. We achieve this by delivering programmes of specialist technical training for both our own people and the contractors who work on our behalf.

5.174 As well as our standard training programmes we also operate a Workforce Renewal Scheme. This helps us recruit and train the next generation of craftspeople and engineers to replace the large number of qualified employees who will be retiring in the next few years. Based on the profile of leavers and our plans for upskilling we will recruit the following:

	Recruitment per annum
Craftspeople	28
Engineers	41

5.175 We will continue to up-skill our existing employees and hire from other DNOs and contractors in the electricity supply industry. We still, though, need to supplement this by training an increasing number of new recruits. As part of this, we opened our new Training Academy in Blackburn in 2013.

5.176 We will spend £48.3 million on training operational employees over RIIO-ED1 which is a saving of 6.7%. We are able to reduce total spending despite the increase in training of new and existing staff by switching from outsourced training to our own training academy and by making our graduate and apprentice training programs shorter but more intense.

Vehicle operations

5.177 We need to operate and maintain our vehicle fleet to ensure it is as efficient as possible. The capital costs associated with replacing vehicles are dealt with in paragraph 5.197 – Replacing our vehicle fleet.

5.178 We run a fleet of 845 operational vehicles. This fleet ranges from small vans through to specialist equipment for installing poles and working on steel towers. The size and nature of the fleet is determined by the operational requirements.

5.179 We plan to improve our fleet's efficiency and carbon footprint through a number of ongoing initiatives including:

- Installation of rev limiters
- More efficient use of the logistics contractor's vehicles in delivery of plant and material
- Close scrutiny of fuel consumption to identify and remedy inefficiencies in the fleet
- Publication of the lowest local fuel prices at each site
- Further use of electric and hybrid vehicles

5.180 Fuel usage is monitored monthly against a volume reduction target of 2% per year from 2012 to 2019. As a result of these and other cost saving measures we have reduced our spending on fleet management by 8.1% to £27.6 million in RIIO-ED1.

Network policy

5.181 These costs relate to the small team of engineering experts who develop and maintain our technical policies, standards and specifications. These specify the equipment we buy and guide both the way in which it is installed and how the network is operated.

5.182 We will spend £3.1 million in this area over RIIO-ED1 which mainly relates to the costs of employing a small number of expert staff, together with the costs of maintaining the technical library. This represents a reduction of 18.5% from DPCR5 due to insourcing control of technical authorship and headcount reductions.

Supporting network operations

5.183 We support network operations with a number of services including running the Control and Customer Contact centres and managing our records.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Running the control centre	19.0	3.8	32.5	4.1	7.2%
Keeping our records up-to-date	7.1	1.4	11.4	1.4	0.5%
Customer Contact Centre	12.6	2.5	27.5	3.4	35.9%
Total	**38.7**	**7.7**	**71.4**	**8.9**	**15.3%**

5.184 The allocation of costs between 'Work Management' and 'Supporting Network Operations' has been refined as we have changed how we carry out and manage these activities to reduce costs.

Running the Control Centre

5.185 The Control Centre is at the heart of our day-to-day operations and allows us to control the entire network. The key responsibilities of the Control Centre are to manage planned network outages and restore power quickly after unplanned outages.

5.186 Our Control Centre operates 24 hours per day, 365 days per year. This will cost £32.5 million in RIIO-ED1.

Keeping our records up-to-date

5.187 It is vital to have good asset and geographical records as these are the basis for carrying out work on site and informing decisions about the future network investment requirements. Records are a key safety management tool in terms of ensuring that anyone working on or near our network knows what assets are in the vicinity.

5.188 We will spend £11.4 million on records in RIIO-ED1. Investment in accurate network data helps ensure our wider investment and repair programmes are as efficient as possible.

Customer Contact Centre

5.189 We operate a central Customer Contact Centre from our headquarters in Warrington, which operates 24 hours per day, 365 days per year to provide our customers with an exceptional level of service.

5.190 We will spend £27.5 million on the customer contact centre over RIIO-ED1. We will improve customer service through improved training and data management. We will supplement this by investment in a flagship Customer Relationship Management system, which will be fully funded by us.

Replacing non-operational assets

5.191 We own and operate a range of assets which are not used in the real-time management of the network but are nevertheless required to support the efficient running of our business. These include IT systems, buildings and vehicles. This section deals with the cost of replacing and renewing these assets. We deal with their operating costs in the next section, Business Support.

5.192 Our total spending on replacement of non-operational assets in RIIO-ED1 will be £38.6 million which is a 68.1% decrease on an annual basis from DPCR5.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Replacing our IT Systems	57.0	11.4	21.2	2.6	-76.8%
Investing in our buildings	6.9	1.4	2.6	0.3	-76.7%
Replacing our vehicle fleet	9.1	1.8	12.1	1.5	-16.5%
Investing in tools and equipment	2.7	0.5	2.8	0.3	-36.0%
Total	**75.7**	**15.1**	**38.6**	**4.8**	**-68.1%**

Replacing our IT systems

5.193 We have to replace our non-operational IT systems to ensure that our people are provided with appropriate IT tools to enable them to do their jobs efficiently and effectively. We have built a future-proof, cost effective IT estate during DPCR5 therefore our RIIO-ED1 investment programme is focussed on cost minimisation.

5.194 Our investment requirements are driven by general technology refresh cycles and the steps we are taking to protect our systems and telephony from hacking and other forms of cyber attack.

5.195 We will be using extended support contracts to increase the operational lives of our IT assets. This means we have to refresh our technology less frequently and lets us optimise whole life IT costs. Consequently, our RIIO-ED1 forecast is based on extended lifecycles for both hardware and software. This is a reduction of 76.8% from our DPCR5 costs to a total of £21.2 million over RIIO-ED1 (see Annex 18).

Investing in our buildings

5.196 We own a number of buildings that house our operational and support employees. Some of these are major sites housing hundreds of people and some are small parts of substation sites used by a few people.

5.197 Where we can, we are realigning our non-operational property portfolio (offices and depots) to owned rather than leased properties. As well as saving money this will ensure that we have consistent and appropriate accommodation across our non-operational estate to support operational delivery.

	Properties Owned	Properties Leased	Total Properties
At commencement of DPCR5	4	13	17
At commencement of RIIO-ED1	10	4	14

5.198 Our total spending on replacing non-operational property over RIIO-ED1 will be £2.6 million which is a 76.7% decrease on an annual basis from DPCR5. For more detail on support costs relating to our non-operational property, see paragraph 5.217- Managing our buildings.

Replacing our vehicle fleet

5.199 We need to replace vehicles when they become worn out or out of date. We also purchase new types of equipment that become available that help us do our job quicker or more efficiently. This includes generators and other forms of mobile plant

5.200 New vehicles are fitted out to an agreed standard by a framework contractor. We have developed components including van racking that can be recycled from one vehicle to the next. This reduces cost and can speed up the turnaround of new vehicles. Electricity North West branding is standard across each vehicle type and is applied by the fitting out contractor.

5.201 We also work with manufacturers to develop safer and more cost effective vehicles. We worked with Toyota to develop and fit out a Hilux model which meets our operational needs but is £10,000 per vehicle cheaper than competitors' equivalents. This is now our standard vehicle for this role.

5.202 To date, purchase and operational costs have precluded the use of electric or hybrid vehicles. In our forecast, we assume that the capability and cost of these vehicles will allow us to incorporate a limited number into our fleet during RIIO-ED1. We have assumed the vehicles will be leased on the basis that changes in technology would be detrimental to a capital payback period.

5.203 We have also assumed that by 2015, the cost of leasing these vehicles will be broadly equivalent to leasing diesel equivalents.

5.204 We will spend £12.1 million on replacement of vehicles over RIIO-ED1 which is a 16.5% decrease on an annual basis from DPCR5.

Innovation

5.205 We have invested significantly in innovation projects during DPCR5 under a number of schemes and intend to continue to do so in RIIO-ED1. In DPCR5, the Innovation Funding Incentive (IFI) which had been running since 2005 was joined by the new Low Carbon Networks Fund (LCNF). IFI enables investment in innovation projects across the range of our activities whereas the LCNF is aimed at trialling new approaches and technologies specifically related to accommodating the growth of LCT on our network.

5.206 In RIIO-ED1, the IFI and part of the LCNF scheme will be replaced by a new Network Innovation Allowance (NIA). We forecast to continue funding projects in these areas at current levels and Section 8 details the Innovation strategy that underpins our identification of future research requirements. As a result, we plan to invest £23.5 million over RIIO-ED1 (see Annex 23).

5.207 In addition, we have three major collaborative projects underway funded via the LCNF Tier Two mechanism – C_2C, CLASS and Smart Street. This is a competitive process managed by Ofgem and we are likely to make further applications both in DPCR5 and in RIIO-ED1 under its successor mechanism, the Network Innovation Competition (NIC). Funding for these projects will continue into the RIIO-ED1 period and we expect to invest a further £4 million on them in that time.

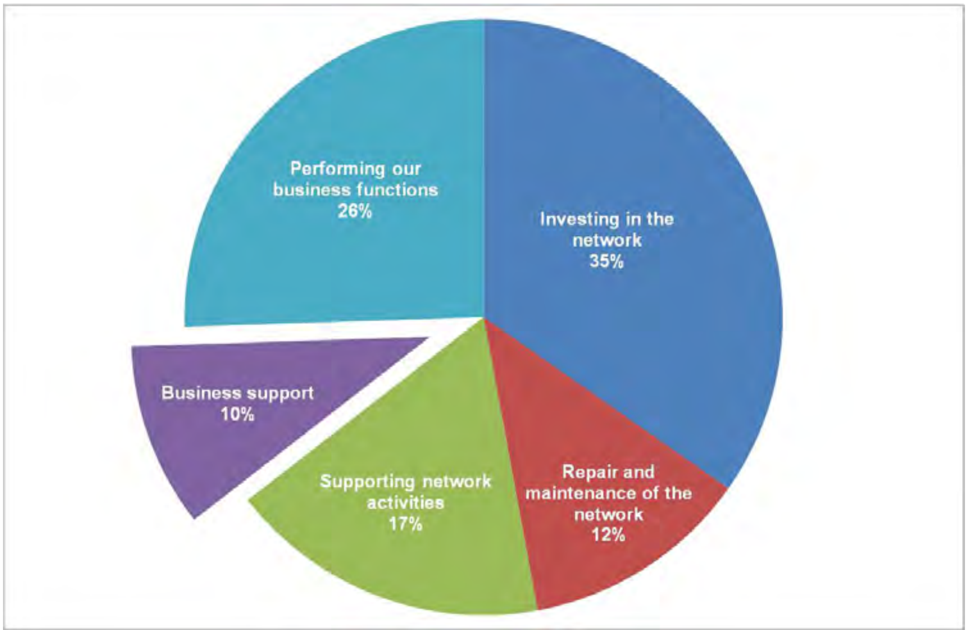
Business support

5.208 We have a number of central support activities which are necessary for the efficient operation of our business. These include managing our IT systems, human resources, building and facilities management, finance and regulation.

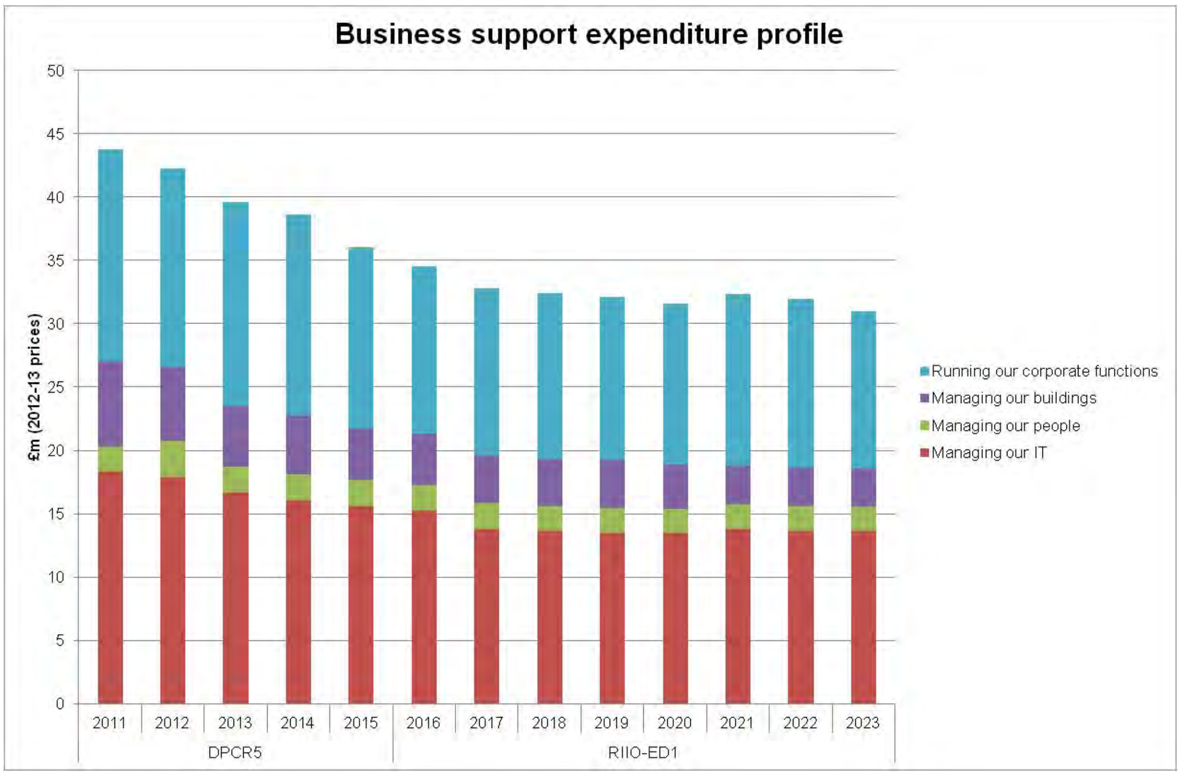
5.209 We have always sought to drive value for money in all support activities. Since we acquired the business in 2007, all business support activities have been tasked with focusing on the services required to support the operational parts of the business so as to deliver improved service more efficiently. We have been consistently driving the cost of these activities down while ensuring that the right level of support is provided to the field teams to ensure that as a whole the business is as efficient as possible.

5.210 As part of this on-going process we have undertaken extensive benchmarking to test our services and the value they provide. We have undertaken a detailed zero-based bottom-up cost assessment of our indirect costs to ascertain the most appropriate fixed and variable costs. During RIIO-ED1 we plan to continue to reduce these costs by 15.5% over DPCR5 on an annual basis.

5.211 We asked KPMG to analyse our fixed cost base and compare this to 'group' organisations, where fixed costs appear proportionately lower because they are spread across a wider range of operational companies. Their analysis suggests that the fixed costs of a 'double' company should be around 30% higher than those of a 'single' company. We have used this ratio to test the proportionality of our fixed cost base to other DNO groups and satisfy ourselves that our fixed costs are both efficient and justified.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Managing our IT	84.5	16.9	110.7	13.8	-18.1%
Managing our people	11.1	2.2	15.7	2.0	-11.4%
Managing our buildings	26.0	5.2	27.8	3.5	-33.1%
Running our corporate functions	78.8	15.8	104.6	13.1	-17.0%
Total	**200.4**	**40.1**	**258.9**	**32.4**	**-19.3%**



Managing our IT

5.212 A number of reviews were undertaken during 2012-13 to benchmark our IT and Telecoms operating model and cost-to-serve, for example to review the provision and usage of data centre services and to examine how we provided back office services. We are acting on the outputs of these reviews to drive significant savings into our IT cost base during the remainder of DPCR5.

5.213 We will do this by:

- Optimising provision of a number of service management functions using the most efficient balance between in-house employees and outsource providers
- Constructing two purpose-built data centres to replace the four we currently operate
- Further consolidation of the Operational and Corporate IT infrastructure and implementation of a revised IT operating model

5.214 We will build on this during RIIO-ED1 by:

- Regular market testing of systems and services in conjunction with contract reviews and commercial re-negotiations to ensure best value
- Use of best practice procurement processes led by the specialist central Procurement team
- Undertaking continuous service improvement exercises

5.215 By the end of RIIO-ED1 we aim to have removed almost 26% of our IT and Telecoms business support costs compared with 2011-12 levels.

5.216 We will spend £110.7 million over the course of RIIO-ED1, which is an 18.1% reduction on equivalent DPCR5 costs.

Managing our people

5.217 We have a centralised Human Resources team, responsible for recruitment, payroll, development and the well-being of our people. They also deliver non-operational training.

5.218 During RIIO-ED1, operational efficiencies mean we can reduce these costs to £15.7 million, a saving of 11.4% compared to DPCR5.

Managing our buildings

5.219 We occupy a number of premises to accommodate our operational and support teams. We have to meet the day-to day running costs (eg heating, lighting, rates and security) as well as pay rent for the buildings which we occupy but do not own. Our property portfolio plan will reduce our leased premises from nine non operational properties to four by 2015.

5.220 Our property strategy is based on investing to improve the utilisation and efficiency, lower the operating costs and mitigate the environmental impact of our property estate. We will do this through the completion of a programme we started in DPCR5, namely:

- Rationalisation of desk space across the estate to get optimum use of accommodation
- Refurbishment of offices at Frederick Road in Salford, Hartington Road in Preston and Linley House in Manchester including replacement of air conditioning and lighting systems with modern energy efficient equivalents
- Construction of a new depot at Whitegate in Oldham incorporating an energy efficient heating and lighting system, excellent insulation levels and PV panels on the building's roof
- Installation of charging points for electric/hybrid vehicles at Frederick Road and Hartington Road with a further 34 points planned for RIIO-ED1
- Installation of Smart Meters across the estate and formal reviews of energy usage with our facilities management contractor to optimise energy efficiency

5.221 As a result, our building management costs in RIIO-ED1 will be £27.8 million, a reduction of 33.1% compared to DPCR5 levels.

Running our corporate functions

5.222 We have to meet a number of legal, regulatory and financial requirements as well as deliver the efficient overall management and support of our business.

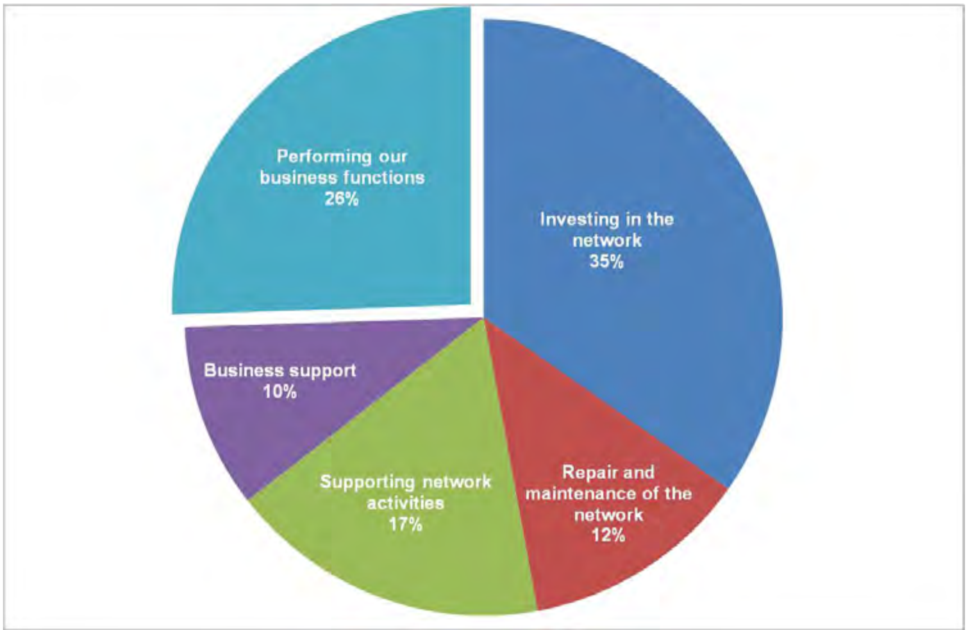
5.223 These activities include paying suppliers, running our finance function, dealing with Ofgem and ensuring regulatory compliance, legal and company secretarial responsibilities, raising finance and dealing with investors and financial markets, communications and stakeholder engagement, managing and paying our taxes and insuring our network and operations.

5.224 We will spend £104.6 million during RIIO-ED1 in discharging these and other obligations. This is 17.0% less than the equivalent DPCR5 cost, which we have achieved through benchmarking, efficiency improvements and consolidation of a number of functions.

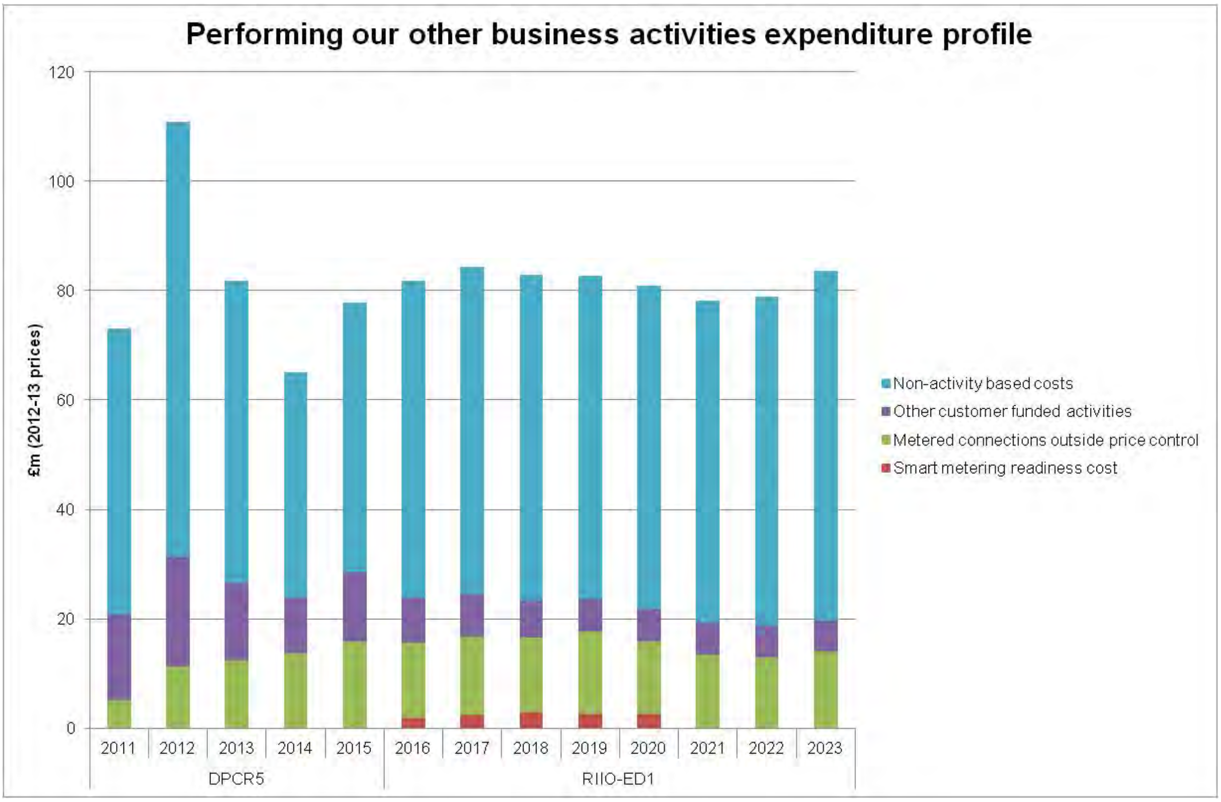
Performing our other business activities

These activities are covered by five categories of costs.

5.225 We undertake some activities that are driven by the requests of individual customers, by the need to support specific projects or to ensure that we comply with the obligations placed on us as a network company. Most of these are funded in slightly different ways to our other areas of expenditure, with many of them funded by the customer who requests the work.



£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Smart metering readiness cost	-	-	12.3	1.5	n/a
Metered connections outside price control	58.1	11.6	110.5	13.8	19.0%
Unmetered connections outside price control	10.2	2.0	7.2	0.9	-55.7%
Other customer funded activities	73.0	14.6	51.8	6.5	-55.7%
Non-activity based costs	277.5	55.5	478.6	59.8	7.8%
Total	**418.8**	**83.8**	**660.4**	**82.6**	**-1.4%**



Smart metering readiness costs

5.226 In some instances work may need to be carried out on our network to facilitate the installation of a smart meter. Much of the work will be funded via an uncertainty mechanism, if and when work is required. Our plan is based on a need to undertake work in 2% of smart meter installations and to comply with a nationally agreed service level agreement.

Metered connections outside price control

5.227 Our customers can choose who makes their connection for them. We offer an end to end connections service. Alternatively they can use an Independent Connection Provider (ICP), who will complete the work required and then transfer ownership of the equipment installed to us to operate and maintain, or an Independent Distribution Network Operator (IDNO) who will complete the work, retain ownership and operate and maintain the equipment on the customer's behalf.

5.228 Irrespective of who the customers choose, they pay for the work to make the new connections to our existing network. These figures represent the gross costs incurred by us in making these connections for all metered connections including distributed generation.

5.229 In some cases, connecting to our network requires us to reinforce the existing network to create additional capacity or ensure any additional load from increased demand does not compromise the quality of supply for new and existing customers.

Unmetered connections outside price control

5.230 There are circumstances in which it is not practical or financially viable to meter a supply as the cost of metering could considerably outweigh the value of the electricity consumed. These are typically connections to street lighting and other highway equipment. Our plan includes the costs we will incur in making new connections, transferring connections to new equipment and disconnecting existing unmetered connections.

Other customer funded activities

5.231 There are other services that we provide to a variety of customers that are charged for separately and our plan includes the costs we will incur in providing these.

5.232 These services include:

- Diversion costs where we have to move our assets as a result of a customer's work eg construction of a new highway
- Where a customer wishes to move their service position
- Revenue protection activities to combat theft of electricity
- Construction of assets for other DNOs or National Grid at shared sites
- Any services to related third parties

Non-activity based costs

5.233 We also incur a number of other costs as part of our operations, including transmission connection point charges, rates, Ofgem licence fee and pension deficit repair costs. We cannot control the amounts we ultimately spend on these activities. We include costs in our plan based on our latest forecasts. Most are subject to uncertainty mechanisms described in Section 7, Managing Uncertainty and Risk.

Total expenditure profile 2011-2023

	£m (2012-13 prices)	DPCR5 2011	2012	2013	2014	2015	RIIO-ED1 2016	2017	2018	2019	2020	2021	2022	2023	RIIO-ED1 Total
Investing in the network	Replacing and refurbishing network assets	52.8	75.2	83.5	79.8	86.1	82.4	71.8	79.1	74.3	82.1	78.3	82.5	79.1	**629.5**
	Managing network impacts	10.3	15.0	16.8	13.9	18.8	16.8	13.3	12.7	14.4	9.9	9.8	9.5	9.5	**96.1**
	Worst Served Customers	-	-	0.2	0.2	0.8	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	**3.4**
	Resilience	3.5	2.3	1.7	0.3	0.0	4.9	2.3	2.3	2.2	0.8	3.2	2.5	2.5	**20.7**
	Quality of Supply	2.6	7.1	5.5	11.0	6.7	-	-	-	-	-	-	-	-	**-**
	Making new connections	23.2	11.6	3.8	3.8	5.1	5.7	6.0	5.7	7.0	6.1	5.3	4.9	5.6	**46.2**
	Ensuring capacity	4.2	10.1	12.4	19.4	23.8	11.3	15.1	9.1	11.9	11.7	12.3	18.4	13.6	**103.4**
	Total	96.5	121.3	123.9	128.3	141.3	121.6	108.9	109.2	110.3	111.0	109.3	118.2	110.7	**899.2**
Repair and maintenance of the network	Repairing faults	29.0	29.0	29.5	28.5	28.7	27.4	27.4	26.9	26.5	26.2	25.8	25.4	25.0	**210.6**
	Severe weather	-	-	-	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	**2.3**
	Inspections and maintenance	11.1	9.5	11.3	8.5	8.2	8.8	8.0	7.7	8.1	7.5	8.4	8.4	7.8	**64.6**
	Tree-cutting	3.3	3.2	3.0	3.3	3.3	3.6	3.6	3.6	3.5	3.5	3.5	3.5	3.4	**28.2**
	Other	1.2	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	**14.6**
	Total	44.5	43.4	45.5	42.0	42.1	41.8	41.0	40.2	40.3	39.3	39.8	39.3	38.4	**320.2**
Supporting network activities	Supporting investment delivery	45.4	47.5	44.4	45.2	44.4	41.5	40.5	39.5	39.1	38.6	38.1	37.5	37.1	**312.0**
	Supporting network operations	6.5	6.8	7.8	8.7	9.0	9.0	9.1	9.0	9.0	8.9	8.9	8.8	8.7	**71.4**
	Replacing non-operational assets	32.2	17.2	7.2	10.5	8.5	4.0	4.4	4.4	4.9	5.5	5.3	5.0	5.1	**38.6**
	Innovation	2.4	3.4	9.5	9.4	14.2	5.7	3.6	3.4	2.9	2.9	2.9	2.9	2.9	**27.5**
	Total	86.6	74.9	68.8	73.7	76.2	60.3	57.6	56.4	55.9	56.0	55.2	54.2	53.8	**449.5**
Business support	Managing our IT	18.3	17.9	16.6	16.1	15.6	15.3	13.8	13.6	13.5	13.5	13.8	13.7	13.6	**110.7**
	Managing our people	2.0	2.9	2.1	2.0	2.1	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	**15.7**
	Managing our buildings	6.8	5.8	4.7	4.6	4.1	4.0	3.8	3.7	3.7	3.4	3.1	3.1	3.1	**27.8**
	Running our corporate functions	16.7	15.7	16.2	15.9	14.3	13.3	13.3	13.1	12.9	12.7	13.5	13.3	12.4	**104.6**
	Total	43.8	42.3	39.6	38.7	36.1	34.6	32.8	32.4	32.1	31.6	32.3	32.0	31.0	**258.9**
Performing our business functions	Smart metering readiness cost	-	-	-	-	-	1.8	2.4	2.9	2.7	2.5	-	-	-	**12.3**
	Metered connections outside price control	5.1	11.2	12.3	13.7	15.8	13.9	14.4	13.6	15.0	13.3	13.4	12.9	13.9	**110.5**
	Unmetered connections outside price control	3.7	3.2	1.2	0.9	1.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	**7.2**
	Other customer funded activities	15.7	20.1	14.3	10.2	12.8	8.1	7.8	6.7	6.0	5.9	5.8	5.8	5.7	**51.8**
	Non-activity based costs	52.3	79.5	55.2	41.3	49.2	58.0	59.8	59.6	59.0	59.1	58.9	60.2	64.0	**478.6**
	Total	76.8	114.0	83.0	66.1	79.0	82.8	85.3	83.7	83.5	81.7	79.0	79.8	84.5	**660.4**
	Total Expenditure	**348.1**	**395.8**	**360.8**	**348.8**	**374.6**	**341.1**	**325.7**	**322.1**	**322.1**	**319.7**	**315.7**	**323.6**	**318.4**	**2,588.2**

Fixed costs

5.234 Electricity North West is the only DNO that is in an ownership structure that does not contain another DNO. As a consequence of this, we incur a level of fixed costs that is higher than other DNOs (because the other DNOs can share costs with companies in the same group).

5.235 We asked KPMG to analyse the level of fixed costs that a single licensee would incur above the level that would be expected of DNOs in an ownership group that included two DNOs. KPMG's report estimated that the fixed cost uplift which Electricity North West should be afforded relative to other DNOs as a result of its single licence status is £10.5 million per year. We included this report in our July 2013 plan and are pleased that Ofgem recognised this as a 'well presented report'.

5.236 We have used the results of KPMG's analysis in testing that our forecast costs represent an efficient level of costs for a single licensee group.

5.237 We accept that single licensee status is not an inherent characteristic and that it is possible that during the course of RIIO-ED1 our status could change. If we become part of an ownership structure that includes one or more other DNO licensee operating in Great Britain (either because our current owner purchases another licensee or because we are sold into a group that already includes a DNO licensee) we agree that an adjustment should be made to our cost baselines for fixed costs to ensure that any fixed cost allowance that we no longer need is returned to customers.

5.238 We propose to introduce a mechanism, to be set out in our distribution licence, to ensure that an appropriate adjustment can be made to our allowed costs. This adjustment would effectively reverse our baseline costs for all or part of the fixed costs that were assumed in our RIIO-ED1 baseline costs at Final Determination.

5.239 In order to ensure that any changes associated with this mechanism are predictable to suppliers and can therefore be passed through to customers, we propose that adjustments would be proposed and made at times set out for other uncertainty mechanisms in May 2019 and at the end of RIIO-ED1 period. These adjustments would take account of any transactions that occurred before those dates so that customers are fully compensated.

5.240 We will work with Ofgem to develop the required licence condition and associated financial handbook chapters and price control financial model modifications to achieve this.

5.241 Annex 29 provides more details of how we have determined the level of fixed costs and our proposed adjustment mechanism.

Pensions

5.242 Almost all of our employees are members of our pension scheme. There are two key sections of the scheme, one that provides benefits linked to salary at retirement (the defined benefits section), and one that provides benefits based on contributions paid in (the defined contribution section). The defined benefits section was closed to new joiners in 2006. All our new joiners are offered membership of the defined contribution section.

5.243 Our costs for the defined contribution section are easy to predict and budget for, as contributions are paid as a fixed percentage of relevant pensionable salary. Predicting costs for the defined benefits section is more difficult, as the balance of cost above employees' contributions is met by the company, and this cost can fluctuate. Our pension scheme is set up under trust with Trustee Directors who are responsible for ensuring that it is run properly. As with all funded UK defined benefit schemes, a Scheme Actuary has been appointed and he completes regular funding valuations. Formal valuations, from which cash contributions are set, are carried out every three years in line with legislative requirements. Our latest valuation is due reflecting the position as at 31 March 2013 and we expect our contributions to change from 1 April 2014.

5.244 As our valuation is still under way, we have asked our actuarial advisers to estimate the contributions we will pay from 1 April 2014 and we have included these estimates in our plan. We also include an assumption that our National Insurance Contributions will increase in 2016 in line with recent announcements from Government about the changes to state pensions and the related National Insurance rates (see Annex 24).

5.245 Our pension costs are included in all the tables in this section. For completeness they are also summarised below.

£m (2012-13 prices)	DPCR5 Total	DPCR5 Annual Average	RIIO-ED1 Total	RIIO-ED1 Annual Average	% Change
Defined benefit scheme contributions	61.0	12.2	100.7	12.6	3.1%
Defined contribution scheme contributions	7.8	1.6	18.9	2.4	52.3%
Pension admin costs	4.1	0.8	6.4	0.8	-2.0%
Pension protection fund levy	0.7	0.1	1.2	0.2	10.8%
Incremental pension deficit	-	-	2.9	0.4	n/a
Total	**73.5**	**14.7**	**130.1**	**16.3**	**10.5%**

Future service costs

5.246 The amount we have to pay into the scheme to fund an active member's future defined benefit accrual is based on calculations by the Scheme Actuary taking into account a number of variable factors such as inflation, life expectancy, asset investment performance and future pay increases.

5.247 This is expressed as a percentage of pensionable salary, and is known as the Future Service Cost. As all our active employee members age by a year together the percentage due per member is likely to increase. As the scheme has been closed to new members since 2006 there are no younger members to lower the average rate.

5.248 Across the electricity industry the DNOs closed their schemes to new members at different times and age profiles and individual demographics of the schemes will differ. We believe that we were one of the earliest companies to close our scheme to new members.

5.249 As defined benefit scheme costs are difficult to predict in advance, before finalising our estimated pension costs for this plan, we looked at costs within different pension risk structures. We refer to these risks within our assessment of the Cost of Equity in Annex 25.

5.250 The range of figures we considered is shown below, and the figures we have used in the plan are highlighted.

2010 valuation figures rolled forward	Established Deficit	Incremental Deficit	Future Service Cost
31 December 2012 – Technical Provisions	£183.5m	£0.1m	37.1%
31 March 2013 – Technical Provisions	£191.3m	£2.6m	40.7% to 45.7%
31 March 2013 – Low Risk (self sufficiency rate)	£311m	£15m	52.2% to 49.5%
31 March 2013 – Least Risk	£464m	£26m	62.1% to 57.5%

5.251 Where historic pension liabilities exceed the invested assets there is a deficit. Deficits relate to historic liabilities and are separate to the Future Service Costs. Deficits can be recovered through cash payments from the employer, from outperformance from the invested assets, or from a mixture of the two.

5.252 Ofgem require that any deficit is split into the Established Deficit (for service prior to 1 April 2010), and the Incremental Deficit (for service after 1 April 2010). Under Ofgem's Pension Principles, the Established Deficit, if judged to be reasonable by Ofgem can be recovered through customer prices as a separate allowance. The Incremental Deficit, together with the Future Service Costs are considered by Ofgem to be part of our total costs of employment within Totex and are subject to comparative assessment and the total ex-ante allowance.

Real Price Effects

5.253 Real Price Effects (RPE) are the differences between the actual inflation we experience across our cost base compared to the inflation allowance we receive through Retail Price Indexation (RPI). We discuss this in more detail in Section 7, Uncertainty Mechanisms.

5.254 Our estimate of RPE inflation for RIIO-ED1 is £82.6 million. We have more than offset this through cost and frontier shift efficiencies.

Ongoing efficiencies

5.255 We recognise that future technological change or new working practices can be expected to deliver further savings beyond current efficient levels. We will continue to deliver efficiency savings and have included stretching assumptions in our plan. Where we expect that our innovation projects will deliver significant savings in a particular area we have included for these.

5.256 We asked Oxera to examine the potential for electricity distribution companies to improve their costs through ongoing efficiency improvements. Their analysis suggested that a frontier shift of 0.7% per year could be expected (See Annex 15). We have challenged ourselves to beat this expectation and have applied a 1% per year saving in our plan across all activities. The exact way in which these savings will be achieved is currently unknown, but we are confident that our innovative ways of working will deliver this.

6 Finance

Ours is a long-term business. We invest in, maintain and manage assets which will deliver for our customers and stakeholders over many decades. As such, it is fair that the cost of renewing, expanding and maintaining our network is spread across the generations of customers who will benefit from it. Spreading this cost is one of the main functions of the regulatory price control

6.1 We need to pay for equipment, supplies, labour and services when we install and use them. We also have to pay for our day-to-day operating expenditure as and when it is incurred. Ofgem has decided that the period over which we can recover our investment costs will be 45 years, an increase of 25 years over previous price controls. This creates a significant mismatch between when we spend money and when we recover the cost through our service charges.

6.2 We bridge this cash flow gap by raising the capital (cash) we need to invest and operate through a combination of shareholder investment (equity) and borrowing (debt).

6.3 Ensuring that the spread of the allowances to recover these costs and the costs of paying the interest on the debt are sufficient to ensure we can meet all our obligations year to year is the key factor to ensure our ongoing financeability.

Developments since July 2013

6.4 Since the previous version of our Business Plan there have been a number of developments in relation to the potential allowances for the Cost of Capital under the RIIO-ED1 price review.

6.5 In our previous plan we set out our concerns about the shortfall in the allowances for Cost of Debt when compared to our actual, efficiently incurred, debt costs. Based on guidance from Ofgem we assumed the Fast Track Reward of £46 million (2012-13 prices) in our forecasts, which together with our innovative proposal to voluntarily defer £25 million of allowed revenue from the last year of DPCR5 into RIIO-ED1, generated a total of some £71 million of additional revenues. Our modelling showed that this additional revenue across the eight years of RIIO-ED1 was sufficient to maintain key financial metrics at levels required to sustain stable investment grade credit ratings. These forecasts also assumed our proposed level for the Cost of Equity at 6.8% which we justified based on detailed reports from Oxera covering the key aspects of the Capital Asset Pricing Model (“CAPM”) including a relative risk analysis supporting an Equity Beta of 0.91.

6.6 Based on this proposed package we were able to conditionally accept that the Cost of Debt allowance should be based on Ofgem’s proposal of a simple 10-year trailing average of single A and BBB iBoxx indices of bond yields less the implied 10-year RPI inflation rate.

6.7 Since Ofgem’s decision not to Fast Track our plan and accept the proposals in the round and to assess plans against a “central reference point” for Cost of Equity of 6.3% we have revisited our Financing proposals and in particular the steps required to ensure the company maintains stable credit ratings and remains financeable.

6.8 As a consequence we are no longer able to accept Ofgem’s policy position for the Cost of Debt allowance and we propose an alternative proposal for different weightings to the trailing average calculation. This amended Cost of Debt allowance forms a key part of our updated business plan.

6.9 In addition, Ofgem’s decision to reduce the Cost of Equity to 6.3% and potentially lower, given its most recent decision published on the 17 February 2014, creates further downward pressure on key financial metrics.

6.10 We believe that the uncertainty over Ofgem’s final decisions on allowances for the Cost of Capital, taken together with the rest of the overall price review settlement for factors such as potential Information Quality Incentive (“IQI”) Reward could create concerns for our key financial stakeholders, including the Credit Rating Agencies but also lenders and investors. Therefore we summarise in this Chapter our proposals for the Cost of Capital allowances as part of our overall business plan but the detailed analysis supporting our proposals is set out in Annex 25 which will be provided to Ofgem only and will not be published at this stage.

6.11 Ofgem has a duty to ensure a DNO can finance its activities under section 3A of the Electricity Act 1989. This means the regulatory settlement must allow us to fund our efficient investment, operating and interest costs and pay a reasonable return to investors.

6.12 Our licence requires that we maintain an 'Investment Grade' credit rating, which allows us to access the global capital markets and helps us negotiate efficient interest rates on our borrowing. Our current credit ratings are:

- Standard and Poor's - BBB+ Stable outlook
- Fitch Ratings Limited - BBB+ Stable outlook
- Moody's Investor Services Limited - Baa1 Stable outlook

6.13 We are confident that given Ofgem's duties and our performance as a leading and efficient DNO we will secure an acceptable package for RIIO-ED1 that, in the round, provides for the long-term sustainability of the business. Our financial stakeholders will then be able to assess the overall settlement and our performance against incentive mechanisms when the final details are known in December 2014.

6.14 The following sections consider the two components of the Cost of Capital allowance in our plan, namely the allowance for our borrowing costs (the Cost of Debt allowance) and that to compensate our shareholders for the money they have invested (the Cost of Equity allowance). We have set out the other components of the package which determine our total revenues for the eight-year period, such as capitalisation rates and depreciation lives, the options we have considered and the basis for the decisions we have made. These sections reflect our updated proposals given Ofgem's decision not to Fast Track our business plan in July 2013 and the recent decision on the Equity Market Returns[3]. Detailed analysis and all supporting reports are in Annex 25.

Cost of Equity

Shareholders seek a return on their investment which is appropriate for the industry sector in which it is invested. As a general rule, the more risk they take, the higher return (reward) they will seek. Investment in regulated UK industries is seen as relatively low risk.

6.15 We calculate our Cost of Equity through a number of contributing components:

- A Risk Free Rate, which is the minimum return we may reasonably expect on long-term, AAA-rated Government debt
- An Equity Risk Premium, which reflects the additional return needed to attract investors into the equity market
- An Equity Beta, which is a 'multiplier', applied to the Equity Risk Premium to reflect the risk of a stock relative to the broader equity market

6.16 We use an established investment risk assessment technique – the Capital Asset Pricing Model (CAPM) – to determine our Cost of Equity as follows:

- Risk Free Rate + (Equity Risk Premium x Equity Beta)

[3] See "Decision on our methodology for assessing the equity market return for the purpose of setting the RIIO-ED1 price controls" published 17 February 2014

6.17 Ofgem had set a Cost of Equity range of 6.0% to 7.2% (post-tax real) for all the RIIO price controls and has agreed the following Cost of Equity allowances in those price controls which have now completed.

Price Control	Risk-free Rate	Equity Risk Premium	Equity Beta	Cost of Equity
Gas Distribution (RIIO-GD1)	2.0%	5.25%	0.90	6.7%
Gas Transmission (RIIO-T1 Gas)	2.0%	5.25%	0.91	6.8%
Electricity Transmission (RIIO-T1 Electricity)	2.0%	5.25%	0.95	7.0%

6.18 In the decision document published on the 17 February 2014 Ofgem did not include a detailed breakdown of the components of the CAPM that it had used to derive its "central reference point" of 6.0% nor for the 6.4% awarded to Western Power Distribution ("WPD") under the Fast Track decision. We can see no logic for a difference in the estimated Risk Free Rate or Equity Risk Premium components of the CAPM since these have to be based on the updated view of observed market data.

6.19 Therefore we conclude that Ofgem's differential between the "central reference point" of 6.0% and the 6.4% awarded to WPD can only be justified based on different allowances for the Equity Beta and we derive these in the table below.

6.20 This shows the comparative components of the CAPM as allowed for in most DNO's July 2013 plans, the Competition Commission decision for Northern Ireland Electricity and our interpretations of Ofgem's November 2013 and February 2014 publications.

CAPM Component	DNO ED1 Fast-track proposals	Ofgem ED1 Nov 2013 Ref Point	CC NIE	Ofgem Feb 2014 Ref Point Assumed build up	Ofgem Feb 14 WPD Fast Track Assumed build up
Risk Free Rate	2.00%	1.60%	1.25%	1.60%	1.60%
Market Risk Premium	5.25%	5.25%	4.75%	4.85%	4.85%
Equity Market Return	7.25%	6.85%	6.00%	6.45%	6.45%
Asset beta	0.38	0.38	0.42	0.32	0.35
Debt beta	0.10	0.10	0.10		
Equity beta	0.90	0.90	0.75	0.91	0.99
Cost Of Equity	**6.70%**	**6.30%**	**4.80%**	**6.00%**	**6.40%**
Cost Of Debt	2.72%	2.72%	3.40%	2.60%	2.60%
Gearing	65%	65%	50%	65%	65%
WACC	**4.11%**	**4.00%**	**4.10%**	**3.80%**	**3.90%**

6.21 Such an assessment would appear to be consistent with Ofgem's February 2014 Decision document which states that:

> *"In light of this central reference point, we assessed that DNOs' cost of equity proposals would only be satisfactory for a company that commits itself to especially tough cost efficiency assumptions. Our assessment was that only WPD's plans would deliver the cost efficiencies consistent with their financial proposals".*

6.22 On the basis that an especially tough cost efficiency proposal links to the level of relative risk in a DNO's plans, failure to deliver the forecast efficiencies is largely a risk for shareholders and so should be reflected in the Equity Beta.

6.23 In Ofgem's assessment of our July 2013 Business Plan it stated:

> *"We conclude that it is a strong overall plan. However, at this stage, we are not convinced that its proposed expenditure allowances are efficient."*

6.24 As set out in Annex 14 our review of Ofgem's methodologies for making its assessment of comparative efficiencies of the Fast Track business plans reveals that a small number of inappropriate decisions were made that had a substantial effect on the results. For example, had Ofgem decided to place more weighting on Totex models, as indicated in its March 2013 Strategy Decision, then it would have concluded that our plan was the most cost efficient.

6.25 In this version of our business plan we submit some amended cost proposals and provide compelling additional justification to support certain areas of our network investment and business support cost proposals. We are confident this evidence will address Ofgem's concerns and the uncertainty expressed in the Fast Track decision.

6.26 We therefore conclude that our this version of our business plan meets Ofgem's definition of "especially tough cost efficiency assumptions" and that accordingly the equity beta measured risk associated with our proposed package is commensurate with that awarded to WPD in the Fast Track assessment. However, we recognise that under Ofgem's emerging methodology for the RIIO-ED1 price review, some premium should attach to Fast Track status. Therefore we accept that on a proportionate basis the Cost of Equity for our business plan should be 6.3%. We provide a break-down of our proposed CAPM components below.

6.27 In the table above we showed our assumed build up of Ofgem's central reference point and the WPD allowance. We have also cross-checked our 6.3% proposal against the fundamentals of the CAPM. We have taken the upper-end of the ranges for the RFR and ERP identified by the CC of 1.5% and 5% respectively. Our basis for this decision is the analysis of Mean Reversion which we set out in Annex 25 and the longer timeframe of RIIO-ED1 period when compared to the NIE review (2012-2017).

6.28 From our assumed build-up of the WPD allowance above we infer an Asset Beta of 0.35 which at a gearing level of 65% translates to an Equity Beta of 0.99%. We take a marginally lower Asset Beta for our base case of 0.34% which at 65% gearing translates to an Equity Beta of 0.96%. This then generates an overall Cost of equity of 6.30%.

6.29 In selecting this level of Equity Beta we note the published arguments pointing to lower levels of Equity Beta for regulated utilities and indeed Ofgem's statement that it will carry out further work on the absolute levels of Equity Beta ahead of the RIIO2 price reviews. However we have to use the inferred levels from Ofgem's February 2014 Decision document within this same RIIO-ED1 price review as the basis for our comparative analysis.

6.30 We also refer to the Comparative Risk Analysis included in our July 2013 plan which was based on work by Oxera which supported an increase in the Equity Beta when compared to the risks in the DPCR5 and RIIO-GD1 price reviews. This included such factors as cash flow risk for the levels of Totex compared to opening RAV, pension cash flow risk and those linked to the longer 8-year price review. This analysis supports the selection of Equity Beta at these levels on a comparative basis. Ofgem has moved away from this focus on comparative cashflow risk it used in the RIIO-GD1 and RIIO-T1 reviews in its assessment of DNO proposals for Equity Beta and gearing. We have therefore not repeated the analysis but remain of the view that it is robust and credible and supportive of our proposed base case position.

6.31 In its Fast Track decision document Ofgem asked companies to submit plans in March 2014 including an assessment of their contingency position if Ofgem fully reflects its "minded to" position of a Cost of Equity at 6.0%. On a consistent basis with our base case proposal we have calculated the lower level of Equity Beta required to result in a Cost of Equity of 6.0% and this is 0.90%.

6.32 In Annex 25 we outline in detail our concerns at the potential impact on key financial metrics of such a reduction whilst holding other aspects of the CAPM constant. We conclude that a reduction in notional regulatory gearing would be necessary to ensure financeability and propose a reduction to 62.5% gearing. We consider that such a reduction is consistent with a further small reduction in the Equity Beta to 0.89%.

6.33 CAPM Components of proposed Base case and potential adjustments for Cost of Equity of 6.0%:

CAPM Component	ENWL base case proposal	Impact at Ofgem Ref. point	Adjustment to notional gearing
Risk Free Rate	1.50%	1.50%	1.50%
Market Risk Premium	5.00%	5.00%	5.00%
Equity Market Return	6.50%	6.50%	6.50%
Asset beta	0.34	0.315	0.335
Debt beta			
Equity beta	0.96	0.90	0.89
Cost of Equity	**6.30%**	**6.00%**	**6.00%**

6.34 In conclusion our base case proposal is for a Cost of Equity of 6.3% on the basis that our overall business plan is sufficiently challenging to justify a proportionate Equity Beta to that inferred from Ofgem's decision and allowance for the Fast Track companies. We have used the levels for the RFR and ERP consistent with the Competition Commission's range for the NIE decision.

6.35 In the event that Ofgem assesses that its "minded to" position should apply, we will require notional gearing to reduce to 62.5% at a Cost of Equity of 6.0% to maintain a sustainable plan

Cost of Debt

Ofgem has introduced a 'Trailing Average' index method to set the Cost of Debt allowances for Electricity and Gas Transmission and Gas Distribution. Ofgem has decided to implement this mechanism for RIIO-ED1.

6.36 The index is based on actual Corporate Bond yields on a daily basis over a preceding 10-year period and averages these to set the Cost of Debt for the current year. The trailing average theoretically removes some of the distortion caused by the use of spot interest rates and creates an objective benchmark for DNOs' debt costs.

6.37 We have some serious concerns about this approach and as we set out in the update for developments since July 2013 are no longer able to accept this mechanism as a basis for setting our Cost of Debt allowance as part of this version of our business plan. The calculation of the index is such that for the first year of RIIO-ED1, nine of the ten years are already fixed. Interest rates in the next few years would have to materially increase to prevent the Simple Trailing Average being lower at the end of RIIO-ED1 than at its beginning. This is the most likely scenario given current all time low interest rates. Based on a forecasting methodology from leading UK banks, including Lloyds Bank and Royal Bank of Scotland, we expect the average real Cost of Debt allowance during RIIO-ED1 will be 2.45%.

6.38 We set out in Annex 25 our analysis and detailed proposals. In summary the simple trailing average allowance will be insufficient to cover our actual cost of debt over the RIIO-ED1 period. We note that the CC allowed NIE an allowance based on 80% of its embedded debt costs and 20% reflecting forecast costs for new debt broadly based on the simple trailing average mechanism. This very much reflected NIE's debt profile during the price review and is very similar to Electricity North West's debt profile. We also note in its recent publication Ofwat has set an allowance for the PR14 review on a similar basis of 80% embedded cost allowance and 20% for new debt based on the water companies' debt profiles.

6.39 We consider that as part of an overall Cost of Capital settlement the CC would most likely grant us an allowance based on 80% of our efficiently incurred embedded cost together with a Cost of Equity allowance that would likely be aligned with its approach for NIE.

6.40 We have calculated what this allowance would be using 80% of our embedded debt costs at April 2015 and 20% using the simple 10-year trailing average. This does give us an enhancement to allowances over what we forecast the simple 10-year trailing average to be.

6.41 However we considered alternatives in an attempt to submit a proposal that is consistent with Ofgem's RIIO-ED1 Strategy Decision where Ofgem said:

> *"if a company can show in its business plan that the 10-year simple trailing average index is not appropriate for its circumstances, it can propose modifications. We will consider the merits of such a proposal when evaluating the business plan and would need to satisfy ourselves that the adoption of a different approach is both robust and justified."*

6.42 We propose two modifications to the mechanism:

6.43 Firstly, given Electricity North West's BBB band credit rating we propose that our allowance should only be made up of the iBoxx BBB band bond index data rather than the average of both the A and BBB band indices

6.44 Secondly, we propose using the 15-years of available iBoxx data at the beginning of RIIO-ED1 and then continuing to extend the trailing average up to 20-years as new data is incorporated. This term better matches the maturity profile of the company's' debt and its worth remembering that the original decision to adopt a 10-year trailing average of the iBoxx indices was heavily influenced by the then available data set.

6.45 Based upon our forecasts, the resulting adjustment to the simple 10-year trailing average has essentially the same impact as using the CC's 80% of embedded cost allowance we refer to in paragraph 6.38. See Annex 25 for the specific forecast values and resulting financial ratio analysis.

6.46 In summary this version of our Business Plan is based on our proposed changes to the cost of debt methodology. We consider that these two changes are entirely consistent with the underlying principle of adopting a mechanistic process for setting the allowance through ED1 and require very little changes to the annual rate setting process for inclusion in the Price Control Financial Model.

Gearing

6.47 Gearing describes the proportionate relationship between equity and debt. In our base proposal we propose to maintain our existing gearing level of 65%, which means that 35% of our total capital comes from investor funds and 65% comes from borrowing.

6.48 Gearing at these levels remains consistent with the credit rating agencies' guidance for an A-/BBB rated network company.

6.49 As set out above in paragraph 6.35 we consider that changes to the notional gearing are an effective financeability solution where the core cost of equity allowance and the overall WACC is insufficient to maintain metrics consistent with a solid investment grade credit rating. Accordingly if Ofgem adopts its "minded to" position on the Cost of Equity allowance then we propose a reduction in notional gearing to 62.5%.

Capitalisation Rate

We meet our day-to-day operating costs through the proportion of our expenditure which is funded from revenue (cash) each year. The capitalisation rate is the proportion of expenditure that is funded over the long term.

6.50 As a single licence DNO, our operating costs comprise a larger proportion of our total cost base and therefore drive a comparatively lower capitalisation rate than that of multi-licence groups, where operating costs are diluted by higher aggregate capital programmes.

6.51 Our capitalisation rate proposal is based on an analysis of our RIIO-ED1 expenditure plans using the current DPCR5 methodology of 'fast pot' and 'slow pot' calculations. This provides an equivalent capitalisation rate of 72%. This rate is broadly in line with our statutory capitalisation rate, which ranges between 72% and 74%, depending on annual capital programme levels and therefore is consistent with Ofgem's Strategy Decision. Annex 25 provides the support for these calculations.

Financeability

All regulated network companies face an inherent cashflow shortfall because they must meet nominal financing costs but their cash allowances are calculated on a real basis. By compensating investors for the effects of inflation through the indexation of the RAV, and not in-year in the allowed cost of capital, the regulatory mechanism creates a potential short to medium term weaknesses in cash flows. Higher assumed gearing levels exacerbate the problem. This feature of the price control review framework means that we must pay particular attention to ensuring our business plan is financeable and test this with sensitivity analysis.

6.52 Ofgem will start its assessment assuming that our actual Cost of Debt exactly matches the 10-year Trailing Average. Their model uses a rate of 2.72% real for the full price review period which is calculated from a ten-year period ending 2013.

6.53 We do not believe that this is a reasonable assumption. We therefore make two key changes in our assessment. First, we use as our base a forecast for the Trailing Average allowance for RIIO-ED1, we construct this by employing a mechanism developed by Lloyds Bank using forward swap curves. This forecast reflects the inevitable decline in the allowance level in the near term.

6.54 Second, we remove Ofgem's assumption that our Cost of Debt will equal their Trailing Average and replace this with our efficiently incurred actual Cost of Debt, calculated on a real basis which strips out an allowance for inflation from nominal rated debt. We assume that any new debt raised in the period is at the then Trailing Average. This is our base case from which to undertake sensitivity analysis.

6.55 These changes have a material impact on the interest and dividend cover ratios. The key Post Maintenance Interest Cover Ratio (PMICR), a ratio developed by the credit rating agencies to assess financeability without the potentially distorting effects of regulatory depreciation, would weaken to below acceptable levels without the mitigating measures we propose. The full detail of our analysis and conclusions is set out in Annex 25.

Financeability solution

Based on our assessment set out in Annex 25 we have decided to utilise two techniques to strengthen financeability to an acceptable level.

6.56 First, we propose to transition to a 45 year asset life over a single price control in line with the profile shown below. This gives an average asset life of 34 years over the course of RIIO-ED1.

2016	2017	2018	2019	2020	2021	2022	2023
23	26	29	32	35	38	41	45

6.57 Second, we adopt the modified trailing average calculation for the Cost of Debt allowance, as set out in this Chapter 6 and in full detail in Annex 25.

6.58 In the event that Ofgem determines a Cost of Equity of 6.0% then a further financeability step of reducing notional gearing to 62.5% would be necessary.

Finance proposals

The previous version of our business plan clearly set out the basis on which we were able to accept the 10-year simple trailing average calculation for our RIIO-ED1 Cost of Debt Allowance, this being conditional on the Fast Track Reward which we proposed to use to explicitly fill the shortfall in debt funding costs. In this version of our business plan submission, without such a reward being available, we are obliged to propose a package which we consider will ensure the financeability and sustainability of our business.

6.59 Our proposed financing package for the March 2014 business plan assessment is as follows:

Cost of Equity	6.3% Post Tax Real
Cost of Debt	Based on iBoxx 15 to 20-year Trailing Average of BBB only.
Gearing	65%
Regulatory Capitalisation	72%
Regulatory Depreciation	One period transition to 45-years in equal incremental steps
Financeability Measure	Ofgem agreement not to penalise us through the under recovery mechanism for a deliberate under recovery of £11 million of revenues from 2015 to 2016.

Impact on customer prices

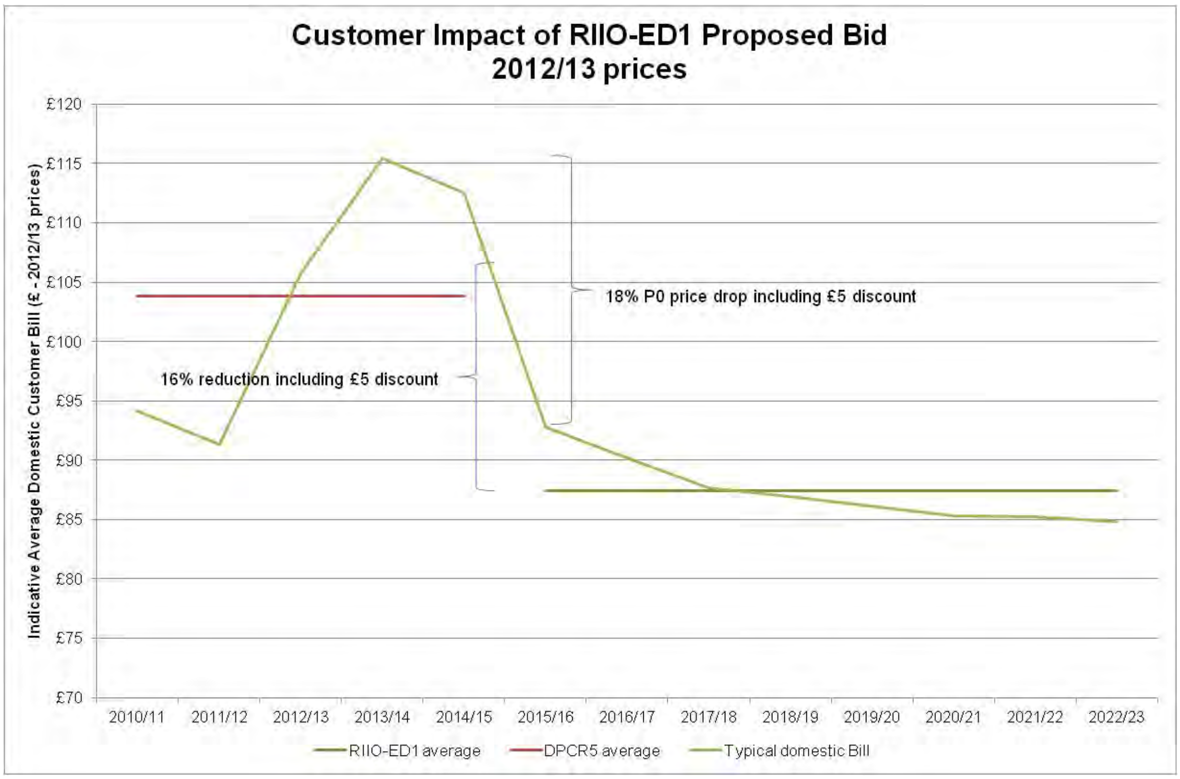
RIIO-ED1 is, in many ways, a gateway to an uncertain future. We recognise our role in helping our customers and stakeholders prepare for that future now.

6.60 We believe our plan demonstrates a prudent, flexible and innovative approach to managing much of this uncertainty and enabling a reliable, affordable and sustainable distribution network. We will achieve all of this at prices which will be, on average, 16% lower than our average DPCR5 prices. We are very proud of this achievement. This also represents a further reduction to customer prices from our proposals in July 2013. The additional savings have been achieved by including more ambitious cost efficiencies, some scope reduction in our planned network investment programme, the effects of removing the Fast Track Reward from our plan and applying a lower Cost of Equity allowance.

6.61 This material price reduction can be achieved whilst still including our financeability proposals to ensure the business can continue to deliver a safe, reliable and flexible network into the future.

6.62 Overall, we are confident that our plan offers excellent value for money for our customers and that the benefits in other parts of the plan outweigh the marginally higher costs. Despite the inclusion of the modified trailing average our customers will pay some of the lowest prices for electricity distribution of any in Great Britain during the RIIO-ED1 period. We have compared the prices in our plan with the information available from all the other DNOs in July 2013. This shows that our prices remain the second lowest of any DNO group. This is not a surprise as our base revenue is over £76 million lower than in our previous business plan submission in July 2013. Last year Ofgem assessed the total costs of each DNO's business plan and their analysis showed that our total costs are amongst the lowest of any DNOs in Great Britain. This efficient cost base feeds directly into lower prices for our customers.

6.63 We consulted with our stakeholders on the profile of prices we should adopt when we published our Strategic Direction Statement at the end of February 2013. The feedback we received, particularly from our external stakeholder panel, indicated that we should reduce prices as quickly as possible to a stable and sustainable level and then hold them relatively constant. The price profile below meets this requirement whilst also taking account of other factors. It results from moving revenues to ensure that a minimum and stable PMICR ratio can be achieved in every year of our plan with our actual Cost of Debt and forecast for the likely path of the modified iBoxx index. The graph also reflects the impact of the £5 per domestic customer discount in 2014-15.



7 Managing Uncertainty and Risk

Any business plan must address risk. The principle we have adopted is that risk should be borne by the party most capable of managing and mitigating it. This means we seek to manage all risks that we can exercise reasonable control over. Consequently our plan allows for all business as usual risks, such as unit costs and delivery, to rest with us and we reflect this in our Cost of Equity calculation.

7.1 Some areas are so uncertain, though, that it is not possible or sensible for us to price the risk into our plan. If we did, it may result in unnecessary price increases being passed on to customers. These uncertainties include load-related investment (including general reinforcement and low carbon technology), smart meter impacts and changes in legislation. In these circumstances, Ofgem offers a range of mechanisms which seek to protect both the DNO and its customers from significant cost and price risk. These include reopening specific aspects of the price control, flexing cost allowances as volumes change and pass-through of certain costs.

Low carbon technology

The Government is committed to legally binding targets to reduce total UK greenhouse gas emissions by 80% compared to their 1990 levels by 2050.

7.2 These targets are underpinned by binding carbon budgets and comprehensive plans to introduce a range of policy measures and stimulus packages to reduce carbon emissions.

7.3 Some of the key enablers are:

- Electric vehicles to decarbonise transport
- Heat pumps to decarbonise heating
- Photovoltaic cells (solar panels) to decarbonise electricity generation

7.4 Widespread adoption of these technologies will increase consumers' demand for electricity. This will place a significant additional load on Great Britain's transmission and distribution networks.

7.5 There are two major implications for our plan. The first is the rate at which these technologies will be deployed and therefore the degree to which we will have to upgrade (reinforce) our network to deal with the additional load. The second is the concentration of these technologies, commonly referred to as clustering.

7.6 We have analysed the DECC future scenarios for different combinations of technologies and incentives to meet the low carbon goal. These are produced at a national level and therefore require a level of moderation when translating them to local impacts. We have used the research we commissioned from CEPA and the Tyndall Centre of the University of Manchester to help us do this and concluded that the DECC Low scenario is most appropriate for our best case forecast (see Annex 8).

Monitoring change

7.7 Experience with the effect of the Government's feed-in tariff for photovoltaic cells has shown that stimulus packages can cause rapid and dramatic changes in consumer behaviour and adoption rates. Similarly, as technology becomes cheaper, more efficient and more accessible, the case for installing it becomes more compelling. Again, this can have a significant effect on consumer adoption rates.

7.8 We have established an effective monitoring programme which will allow us to respond quickly to changes in low carbon adoption rates.

7.9 The main indicators we use are:

- Government policy and market stimulus initiatives that may trigger changed behaviour or faster adoption

- Marketing activity by specialist providers of low carbon solutions
- Pricing and development trends in low carbon technologies
- Trends in connection activity for low carbon installations

7.10 Monitoring connection trends is facilitated by the registration required for heat pumps to be eligible for the Government's Renewable Heat Incentive and for photovoltaic cells to be eligible for the Government's Feed-In Tariff. IET wiring regulations mean customers are required to notify us of the installation of electric vehicle charging infrastructure. We believe that this and similar active monitoring will give us between six and 12 months to flex our plan in response.

Flexing our plan

7.11 We want to play our full part in enabling the transition to a low carbon future. This means we need to take reasonable steps to ensure our customers and communities can benefit from low carbon technologies when they want.

7.12 We already operate a Connect and Manage programme, whereby we facilitate low carbon connections to our network and undertake to manage any load implications while the case or need for reinforcement is developed. We will continue this programme through RIIO-ED1. We will improve it through the use of smart meter data, which will help us analyse load requirements on our low voltage network, where we expect most of the low carbon technologies will be deployed.

Distributed generation

7.13 The Energy Act 2013 contains enabling legislation that will provide for Electricity Market Reform, the development of a capacity mechanism and new Feed-In Tariffs for renewable generation. DECC have forecast the effect that this will have on the economic case for renewable generation at the scale that connects to our network (known as Distributed Generation). We have based our forecasts on the very latest information and forecasts for Distributed Generation provided by DECC.

Other load-related investment

7.14 Our investment proposals are also based on our assessment of economic growth and the associated impact on demand and connections. Our independent analysis supports a view that economic growth and social expansion in our region will be relatively modest and our forecasts reflect this. The risk of a significant variation in load related expenditure will remain throughout RIIO-ED1.

Efficiently managing these uncertainties

7.15 Ofgem has proposed that we should be able to reopen part of the price control in circumstances where our forecasts of load-related expenditure are out by more than 20%. We support this and think it provides the most cost-effective solution for our customers.

Smart meter implementation

The Government's smart meter programme requires the installation of smart meters in all domestic and small commercial premises by 2020. We plan to use smart meter data to improve the way we interact with our customers and manage our network. We also have a role in supporting the smart meter installation programme.

7.16 The rate at which smart meters will be rolled out remains unclear. The completion date of 2020 is now one year later than originally planned, primarily to allow the electricity and gas retailers to agree data and system designs and complete their testing programmes. Whilst there is scope for the end date to move again, we are confident that Government and industry support for the smart meter case means this would not be beyond the end of RIIO-ED1.

7.17 Smart meters will be installed by meter operators on behalf of electricity suppliers. When they do, they will carry out a complete safety inspection of the meter, the cut-out and associated installation. Where the cut-out is found or suspected to be defective, the meter operators will look to DNOs to carry out the necessary repair work. Where we are required to undertake this work we will comply with a nationally developed service level agreement setting out DNO and supplier obligations which we support.

7.18 Estimates for the rate of cut-out interventions vary. Early analysis suggested that as many as 7% of installations would require remediation. Later analysis suggests this number may be closer to 2%.

Efficiently managing these uncertainties

7.19 We have based our plan on the 2% estimate. We will monitor actual rates as the smart meter programme progresses. Where volumes increase beyond this estimate, Ofgem has proposed a volume-driven price adjustment which assumes unit costs will become more efficient as volumes increase. We think this is an equitable approach for our customers, our company, the meter operators and the electricity suppliers.

7.20 DNOs will have to pay for access to and use of smart meter data. The costs of this access and use are difficult to forecast whilst the data and system designs are still being finalised.

7.21 Ofgem proposes a pass-through mechanism for these costs until full deployment is complete. Thereafter, their expectation is that on-going costs will be offset by operational efficiencies. We agree with this approach and have reflected it in our business plan. In total we forecast that customers will receive over £20 million of direct benefits across our RIIO-ED1 and RIIO-ED2 business plans. These benefits will be realised across the latter third of RIIO-ED1 and increase significantly in RIIO-ED2. To enable these benefits we will invest a total of £18.1 million, £3.1 million of which will be funded from our existing DPCR5 allowances.

7.22 The above savings are based on the DECC low LCT adoption scenarios. Savings under higher adoption scenarios are likely to be much higher. In particular, the forecast reduction in losses is the minimum value likely to be observed, however under higher LCT growth scenarios coupled with the introduction of active time of use tariffs by Suppliers, then this benefit could rise to as much as £9 million pa by RIIO ED2 equating to over £72 million of additional benefits for customers.

7.23 In addition to losses savings, time of use tariffs under the high scenario would be likely to add a further £4.8 million of reinforcement savings pa by 2025 totalling an additional £29 million in the ED2 period.

Traffic Management Act

The Traffic Management Act 2004 details the regulations that we must follow when working in the public highway. The Act has been progressively implemented since 1 April 2008 and gives Highway Authorities the powers to introduce Permit to Work regulations and charges. Under these arrangements, the Highway Authorities can introduce specific restrictions, requirements and charges for the work we need to do on public streets.

7.24 Permit to Work powers are being implemented at different times and different rates by each of our region's Highway Authorities. We have included a reasonable estimate of costs for RIIO-ED1 based on the charging we have experienced so far in a few areas where we operate, such as St Helens. We have also made an estimate of the much greater levels of costs we could incur as new schemes recently introduced in Greater Manchester are fully implemented.

Efficiently managing these uncertainties

7.25 A mechanism to address this uncertainty already operates in the DPCR5 price control. Ofgem has proposed that this mechanism be continued in RIIO-ED1. Whilst we have not needed to invoke the uncertainty mechanism in DPCR5, we believe that implementation in Greater Manchester could result in approximately £20m of additional operating costs. In the event that actual costs are significantly greater than our forecast, we will submit evidence for an adjustment to our allowances in line with the 2019 reopener mechanism proposed by Ofgem.

Changes in legislation

Our plan is based on existing EU and UK legislation.

7.26 We are aware of a number of potential EU legislation changes that would affect it, including:

- Generation Connection Code
- Demand Connection Code
- Interconnector Status
- Creosote – used in the treatment of woodpoles
- SF_6 usage

7.27 We are actively engaged in monitoring and influencing developments with a view to protecting our customers' interests.

7.28 The RIIO-ED1 price control has a specific review process whereby we and Ofgem may consider whether the Outputs we are required to deliver have materially changed. This is to take place in 2019, if required, and is referred to as the mid-period review. Given the significant uncertainty of this legislation being enacted, its timing and cost impact, Ofgem's preference is to address any implications at the mid-period review. We agree that this is an appropriate solution.

New nuclear power station in Cumbria

NuGen has applied to National Grid Electricity Transmission for the connection of a 3.6GW nuclear power station at Moorside near Sellafield. To enable this connection, National Grid will need to provide 4 x 400kV transmission circuits. At present, no firm commitments on the timing of the connection works or the route for the transmission circuits have been made.

7.29 NuGen have submitted a modification application to National Grid Electricity Transmission to commence the formal application process for a connection to the transmission network. National Grid and Electricity North West are preparing a modification offer for approval by NuGen. The optioneering process undertaken by National Grid in co-operation with us and regional stakeholders has been wide-ranging and has considered overhead lines, underground cables and sub-sea cables; AC and AC/DC solutions have also been considered.

7.30 Following consideration of the many options National Grid announced that they are considering the three particular options. . The most likely option has a significant impact on our 132kV distribution network, whereby National Grid's proposals would mean displacing our existing lines to establish a 400kV overhead line double circuit around the west coast of Cumbria.

7.31 We do not expect our customers to meet any part of National Grid's costs or the consequential costs of accommodating their chosen route. It is likely, though, that we would have to upgrade or replace some of our assets as a result. Where this is the case, and our customers benefit from it, then the costs will be reflected in our charges (see Annex 26).

7.32 Our options are to:

- Include the costs and risk in our base plan and reflect this in prices to customers
- Incur the costs and reflect these in prices through the annual iteration process
- Use the existing High Value Project uncertainty mechanism, which is available to all DNOs
- Use the Strategic Wider Works uncertainty mechanism, which is generally only available to Transmission operators

7.33 The first option is inappropriate because customers would be required to pay for the project, even if it is delayed or does not happen. The second and third options place a significant additional cash burden on us and the resultant Cost of Equity needed to compensate for this and maintain our Investment Grade credit rating is substantially beyond the reasonable range that customers could be expected to bear.

7.34 Ofgem has suggested that we use the established Strategic Wider Works uncertainty mechanism. We think this is a sensible approach which will ensure our customers pay for those assets and services which benefit them, but only when the cost, timing and scope of the work is known.

7.35 We have already established a collaborative and constructive relationship with National Grid and NuGen. We will continue to work with them to ensure our customers' interests are properly considered and to play our part in enabling a significant addition to UK low carbon generation capacity.

Rail Electrification

The Government is committed to investing in a programme of electrification that will help transform the railway and provide Britain with a sustainable world-class transport system. Network Rail is electrifying key rail routes across the North of England. This work involves a considerable number of diversions of our assets where they are in effected roads and bridges.

Manchester to Liverpool, and Huyton to Wigan: by December 2014

7.36 We have worked with Network Rail to modify bridges between Newton-le-Willows and Liverpool, and Huyton and Wigan. Work is now continuing to install the overhead line equipment to allow electric trains to be introduced between Manchester Victoria and Liverpool, and Liverpool and Wigan, by December 2014.

Preston to Blackpool: by May 2016

7.37 A fully electrified route between Preston and Blackpool will connect the area to the west coast main line; the key rail artery linking the North West with London and Scotland. Network Rail have already upgraded 15 bridges. Overhead line equipment on this route will be installed in 2015/16.

Manchester to Preston: by December 2016

7.38 Work on modifying the bridges and tunnels will start in the spring of 2014 and continue through 2015, followed by the installation of the overhead line equipment. The line will be fully electrified by December 2016.

Oxenholme to Windemere and Wigan to Lostock

7.39 The Department for Transport announced in the autumn of 2013 additional funding to electrify these routes. Network Rail is currently carrying out an assessment of the structures to understand which need to be modified for electrification.

Manchester to Leeds and York

7.40 Funding to electrify the North Transpennine route was announced in November 2011. Work has started on modifying bridges on the first phase of the Transpennine route from Manchester Victoria and Guide Bridge to Stalybridge, which will be fully electrified by December 2016. East of Stalybridge, Network Rail is currently carrying out an assessment of the bridges and tunnels between Manchester and Leeds once complete, a fully electrified route will be provided between Manchester, Leeds and York by December 2018.

7.41 There are a number of potential diversions on the Preston to Blackpool, Manchester to Preston and Manchester to Leeds phases of this work. We are aware that Ofgem have agreed a mechanism to advance fund similar costs in other DNOs' business plans, with an uncertainty mechanism to companies to allow these costs to be returned to customers if another party ultimately funds the work. We have made a provision for the NRSWA diversions within roads and bridges in our submission, but we have made no provision for overhead line diversions. Following extensive dialogue between DNOs, Network Rail, Treasury and Ofgem we expect these to be recharged to Network Rail. We are aware of at least six 132kV and four lower voltage overhead line diversions with an estimated capital cost of £1.75 million but have assumed that these will be recharged and will not be paid for by our customers. We do not believe that including an uncertainty mechanism with the advanced funding of these costs would be in our customers interests and have not included this in our business plan.

Real Price Effects

Inflation is generally measured by the Retail Price Index (RPI) and our income is adjusted to match RPI each year. This mechanism manages the general inflationary uncertainty associated with both new and existing assets. However, the types of goods that we purchase are very different from the basket of goods that are used to measure RPI.

7.42 Inflationary pressures on our cost base are driven by copper, steel, oil and other commodity prices, construction costs, specialist labour rates and capacity in the contractor market. We purchase a lot of equipment from global markets and with other parts of the global economy potentially performing better than the UK; this may create further differences between domestic RPI and the inflation we face. Contractor and specialist labour rates may also increase beyond RPI when demand, particularly in the infrastructure sector, outstrips capacity.

7.43 The difference between general inflation (RPI) and the actual inflation we experience is known as the Real Price Effect (RPE). We commissioned EC Harris to forecast the RPE outlook for RIIO-ED1. We reviewed their analysis alongside our own economic projections and determined the RPE impact on our RIIO-ED1 plan (after we have mitigated some of these increases) is £82.6 million (see Annex 16). We have fully offset this impact with efficiencies.

Pass through costs

We are unable to manage the costs of our licence fee, which is determined by the level of activity in Ofgem, National Grid's Transmission Connection Point charges and our overall rates bill which is determined by the Government's Valuation Office.

7.44 The existing DPCR5 mechanism allows us to pass any variation between actual and forecast costs to future prices. Ofgem has proposed to continue this mechanism in RIIO-ED1. We think this is an appropriate way to keep the risk balance between customers and ourselves constant.

Flexing our delivery model

The framework arrangements in our delivery model mean that we can flex contractor support to respond to changes in our reinforcement programme, whether in response to low carbon, socio-economic factors or the proposed Moorside nuclear power station.

7.45 Our RIIO-ED1 investment programme has a relatively smooth year-on-year profile. This helps us optimise delivery efficiency by giving our operational team and contractors a stable base from which to develop their plans. The monitoring steps we discuss above will give us sufficient time to revise these plans should the need arise. Plan revision will include flexing operational and contractor support to deliver an increased investment programme (see Annex 7).

7.46 Clearly, there is finite capacity in our internal workforce and the contract market. In the event that the DECC High scenario materialises, we believe there would be significant pressure on our delivery programme. Whilst we could look to secure substantial additional capacity, we do not think this is the most economic approach to take. Instead, we will re-profile those parts of our core investment programme which are less time-critical and thereby create space to accommodate any major shocks in low carbon adoption rates. We have assessed our plan and identified that on average just over 10% of any year's investment activity could be moved by two years to help optimise capacity.

Managing charging volatility

We recognise that volatility in our use of system charges to electricity suppliers could result in them including a risk premium in customers' bills. Our proposals are designed to minimise the need for such a premium.

7.47 The design of the price control means that many of the revenue components which give rise to volatility in charges are not factored into charges until two years after the details have been finalised. These components include rewards and penalties under the incentive mechanism, the recovery or repayment of revenue from previous years and the funding of additional costs allowed under the uncertainty mechanisms described above.

7.48 We already provide electricity suppliers with long-term projections of our expected revenues and charges and we plan to supplement these by giving 15 months' notice of indicative tariffs along with the assumptions underpinning them. This gives electricity suppliers the predictability they need in making their offers to customers and is consistent with Ofgem's proposals on risk allocation designed to keep customers' electricity bills to a minimum.

8 Innovation

Innovation is one of our core values and we constantly challenge and improve the way we do things. Innovation is about delivering new technical solutions and changing the way we do our day-to-day activities so that we continue delivering more for our customers now and in the future.

8.1 This is an exciting time for our business; we face unprecedented change in the face of emerging challenges and opportunities brought about by decarbonising our energy supplies, the economic needs of our customers and the ever increasing importance of the reliability of energy networks. Our customers and stakeholders should be assured that our business plan is designed to meet these challenges and deliver the benefits, efficiencies and services they need.

8.2 We have an enviable innovation track record. We are leading the industry in developing innovative solutions that transform the way in which DNOs distribute electricity. Our innovations deliver significant benefit for the amount of investment made, with many innovations achieving more than a tenfold return for stakeholders and customers.

8.3 Core to our business plan are three critical developments; our innovation strategy, our smart meter strategy and our smart grid strategy. Our innovation strategy (Annex 29) describes our overall approach to embracing and developing new techniques and technologies for the benefit of our stakeholders. Innovation pervades all areas of our business plan from customer service, asset management planning and field delivery.

8.4 Key to our businesses success will be the realisation of the significant potential of smart meters and smart grids. Our strategy for realisation of the benefits of smart meters is outlined in our smart metering strategy, Annex 28 and Annex 13 outlines our smart grid strategy.

8.5 Our strategy for innovation is aligned to our four stakeholder priorities of reliability, affordability, sustainability and customer service and we measure our success by the level of improvement we make in these areas.

Why innovate?

Changes in future demand on our network and services are inevitable but difficult to predict. Our continued success is dependent upon how we plan for an unpredictable future.

8.6 Over the past five years we have seen dramatic changes in the local, national and global economies and greater demands for the protection of the environment and the communities we serve. These challenges will continue through RIIO-ED1.

8.7 Working with CEPA (Cambridge Economic Policy Associates) we anticipate that over the next 10 years we will see:

Network	Network capacity being pushed to its limits using ageing infrastructure and assets
	Continued unpredictability in economic growth in the region
	Alternative methods for the storage of excess energy and greater flexibility in network loading and capacity
Customers	Customers demanding greater transparency over the way in which they are charged for electricity and more control over their own electricity consumption
	Demands for improved quality of service
	Extensive smart meter roll-out
Carbon and Social	Greater demands for electricity as more customers switch from gas
	Domestic use increasing by up to 20% through the connection of Low Carbon Technology (LCT) to the network
	Continued upward pressure on energy prices

8.8 Unprecedented market uncertainty and increased focus on social and environmental issues over the past five years has taught us that adapting to change quickly is critical. We have used innovation to deliver increased reliability, sustainability, affordability and service for our stakeholders and customers by continuously challenging and improving the way we do things.

8.9 We have an excellent pedigree in leading UK-wide innovation in our industry. Significant cost savings, efficiency improvements and increased levels of customer service are delivered by DNOs across the UK using innovation developed and shared by us. We think we should continue to invest in innovation to support collaboration between DNOs and industry partners and the collective impact of implementing UK-wide initiatives on the national economy.

8.10 We will invest over £26 million in innovation in DPCR5 and propose to invest at least £24 million in RIIO-ED1. These investments will deliver £133 million of customer savings in RIIO-ED1 and an anticipated £180 million in RIIO-ED2.

8.11 Our innovation programme includes work we will complete with our partners, work we will conduct with other network operators and work led by others that we will adapt for use on our network. We are seeking an innovation funding rate of 0.8%, equivalent to £3 million per annum for RIIO-ED1. This funding is essential to allow us to complete our innovation plans and deliver the customer benefits included in our plan.

Innovation principles

8.12 Our approach to innovation is based on the following principles:

- Understanding the changing needs of our customers and stakeholders as the UK decarbonises and the key role we can play in facilitating it
- Seeking to collaborate with partner organisations to develop solutions and learn from or pass on our knowledge
- Focussing upon customer involvement in all our innovation work ensuring that innovative commercial solutions and the evolution of smart customers drives our programme

8.13 This means we have a problem-led rather than product-led approach, which ensures that we target our innovation around meeting needs in the most practical and cost effective way.

Innovation governance

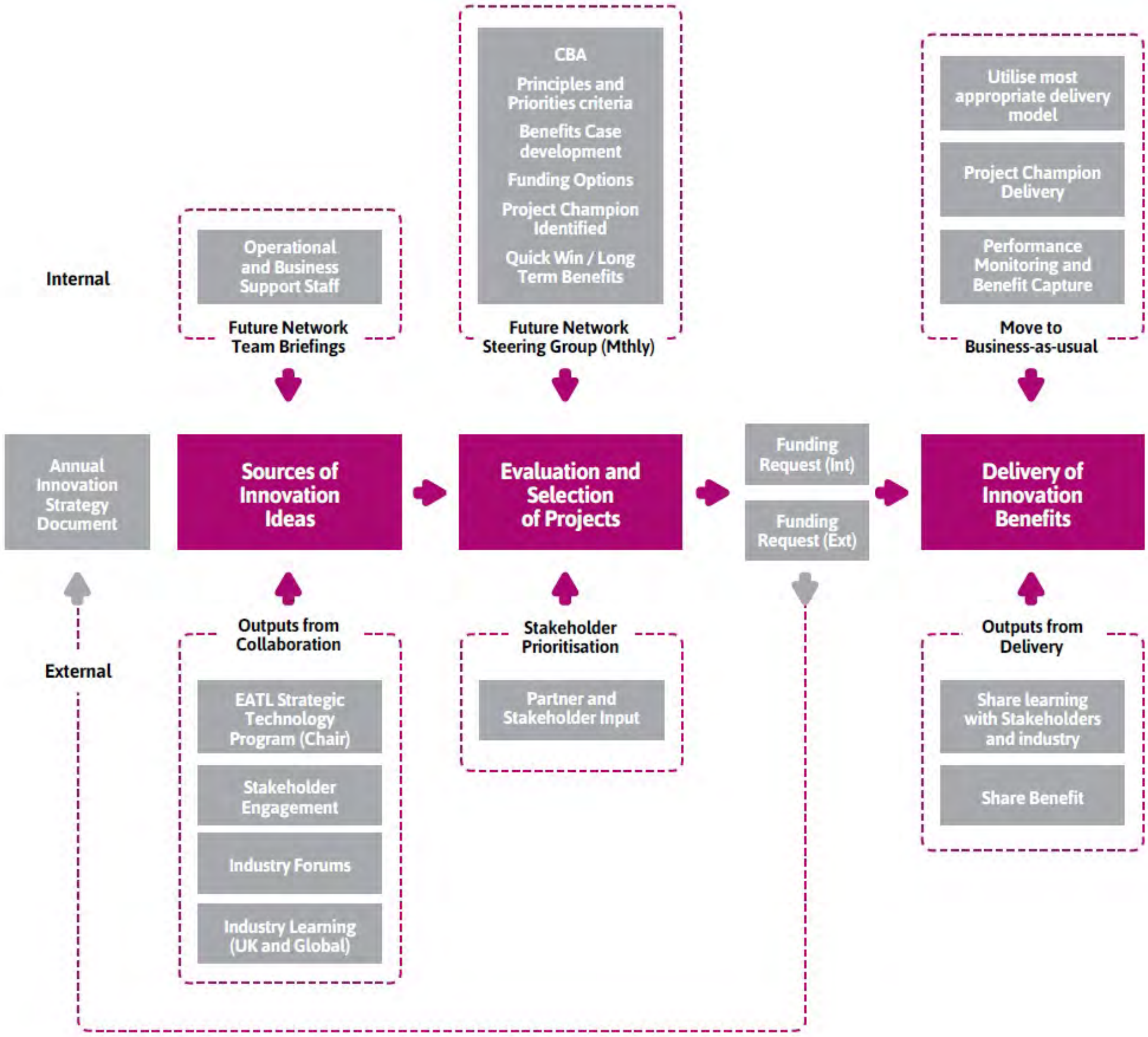
We apply robust governance to the process for identification, selection and delivery of innovation projects.

8.14 This ensures our investment in innovation is tested and validated and the impacts understood prior to rolling out as a business-as-usual activity.

8.15 We have developed an internal process to ensure each innovation project has a subject expert to act as a project champion. The project champion is responsible for defining how the project would be rolled out into business-as-usual and how the project benefits would be measured. We also have a small, centralised team of specialists within our Future Networks team who are responsible for promoting innovation and developing business cases for each initiative.

8.16 We have defined processes in place to ensure every stage of new innovation projects is assessed by representatives from the relevant business section. We also encourage our staff to bring forward innovative ideas and suggestions. The development of the Bidoyng smart fuse is an example of a successful innovation identified and developed by one of our engineers that has now become business-as-usual for us and many other DNOs.

8.17 The diagram below shows the generic governance process in place for innovation, together with the associated fora and reporting requirements.



Funding innovation activities

Innovation is jointly funded by us and customers.

8.18 The Innovation Funding Incentive (IFI) mechanism was introduced in DPCR4 to foster technical innovation within electricity distribution networks. In DPCR5 Ofgem created the Low Carbon Networks Fund (LCNF) Tier 1 and Tier 2, the Smart Grid Forum and Smart Metering Consultation to stimulate the industry to respond to future challenges. Specifically, the LCNF is designed to promote the innovation, trial and deployment of new technologies and commercial mechanisms. We also receive funding from bodies such as the Engineering and Physical Sciences Research Council (EPSRC) to offer under-graduates and graduate students internships within our organisation to work on innovation projects.

8.19 Funding is provided on an annual basis and determined by the submission of well-justified innovation plans for the price review period (see Annex 23). So far in DPCR5 we have funded around £9 million in innovation projects. External funding has contributed a further £8 million.

8.20 RIIO-ED1 introduces a new innovation funding mechanism called the Network Innovation Allowance (NIA), which replaces the existing IFI mechanism, and the Network Innovation Competition (NIC) which replaces LCNF Tier 2. The level of the award is determined by the well-justified innovation plan for the price review period with a clear emphasis on delivering specified output measures.

8.21 This business plan outlines our NIA requirements for RIIO-ED1.

Our track record

Our robust governance process and the application of our innovation principles has helped us select and support innovation projects which have consistently delivered a sustainable benefit for our stakeholders greater than the level of investment.

8.22 We are one of the few DNOs to have successfully invested our DPCR5 IFI funding each year. The success of our LCNF and IFI-funded initiatives means our customers will share in around £140 million of savings which we will deliver by the end of DPCR5. The table below highlights our funded innovation projects and the benefits delivered in DPCR5 and projected for RIIO-ED1.

8.23 Our innovation strategy (Annex 23) highlights our funded innovation projects, the benefits delivered in DPCR5 and projected savings for customers in RIIO-ED1.

Delivering innovation for customers and stakeholders

We invest in innovation to deliver value for our stakeholders, either in monetary terms through more efficient investment or in quality terms through better network performance or customer service.

8.24 Our partners are essential to the success of our innovation strategy; without them we could not harness the technology available to deliver benefits to our customers. We strive to build strong relationships with our partners;

> *"Innovation is approached differently by each of the network companies; with Electricity North West innovation is more innate, with change coming from within the organisation. It is evident that there is strong leadership, and a consistent approach towards innovation, with customer value at the centre."*
>
> *Kevin Tutton, UK Divisional Lead – Smart Grid, Siemens*

> *"We have worked on several projects together with Electricity North West and have always found them to be exceptionally receptive towards new ideas and concepts. Moreover, many of our existing products would not exist had it not been for the open and collaborative approach taken by the Electricity North West leadership."*
>
> *Peter Cunningham, Managing Director, Kelvatek*

> *"In all cases, Electricity North West has demonstrated its commitment to develop and implement solutions which benefit the company, their consumers, and the industry as a whole."*
>
> *Robert Davis, CEO, EA Technology*

> *"Electricity North West is leading the UK in radical solutions to our distribution network challenges and your Capacity to Customers and CLASS projects are of global interest and significance."*
>
> *"Your activities on how low carbon technologies and electric vehicles will affect LV networks are of crucial importance to the EU, and especially in typical European cities such as Manchester."*
>
> *Professor Peter Crossley, Head of Electrical Energy & Power Systems, the University of Manchester*

Innovation Initiative	Funding Type	Project Cost	Benefit	Saving Projection DPCR5	Benefit/ Saving RIIO ED1
Stakeholder Priority - Customer					
Network Operation - Development of a time domain relectometry approach to LV fault finding	IFI	£7,000	Delivers faster repairs with less time and excavations to locate the fault saving repair costs and CML	£3.6m	£14.4m
Network Operation - Delta V Developments & Trial Development of a voltage gradient approach to LV faults finding	IFI	£63,000			
Network Operation - Modular/Master Slave Rezap - Development of an LV autorecloser that will fit into all ENWL's LV fuse pillars and boards	IFI	£316,000	Reduces impact of transient faults by autoclosing post fault		
Network Operation - FuseRestore/Bidoyng - Development of a device to automatically restore a fuse after a transient fault	IFI	£453,000			
Network Operation - Smart Fuse	LCNF Tier 1	£350,000	Reduces impact of transient faults by autoclosing post fault		
Network Operation/Investment Planning - Chromatic Analysis of Insulating Oil - Non-intrusive testing of Insulating Oil	IFI	£116,000	Removes the need for oil samples to be remove from transformers for analysis and allows more frequent oil monitoring		£50k pa
Network Operation - Wide Area Data Gathering - Installation of a Power Line Carrier System	IFI	£95,000	Reduces the reliance on third party telecoms providers and reduces costs and increases security of communications		£100k
Network Operation - Next Generation LV Board/Link Box - LV Network Automation	IFI	£579,000	Release additional capacity from distribution transformers and reduce network losses, load/generation connections at lower cost, improved power quality	-	£5.5m
Network Operation - Customers - Research into the customer/DNO interface and how it can be improved	IFI	£283,000	Faster more accurate information provided to customers -improved customer experience	-	Qualitative
Network Operation - Demand control - Investigation of DNOs' capability to offer technical solutions to support transmission network stability	IFI	£31,000	Allows distribution networks to be used to assist with national objectives for the adoption of renewable energy generation without customers being impacted	-	Qualitative
Network Operation - Composite Link Box Lids - Investigation of composite materials	IFI	£11,000	Provides faster restoration times following faults	-	Qualitative
Stakeholder priority - Reliability					
Investment Planning - Oil Regeneration - Testing the capability of oil regeneration to improve health index	IFI	£270,000	Study with Manchester University into benefits of regenerating transformer oil on site to extend their asset life	-	£33m
Investment Planning - CBRM - Developing the ability to use CBRM outputs to define non-load investment programmes	IFI	£540,000	CBRM was initially developed for DPCR4, we have continued to develop this technique which has become the industry standard approach to asset management - improved asset decisions reliability	>£50m	£65m
Investment Planning/Network Operation – Vegetation Management - Identification and definition of vegetation growth rates as affected by climate	IFI	£298,000	Enables targeted preparation for the affects of climate change	-	Qualitative
Safety Network/Operation - Transient Resonance Study - Investigation into the effects of switching transformers with long cables	IFI	£70,000	Eliminates the need to provide high voltage switching devices on long cables (avoiding costs)	£8.7m	-
Investment Planning - Network Resilience - Investigation into the potential impacts of climate change on network resilience	IFI	£24,000	Enables targeted preparation for the affects of climate change	-	Qualitative

Innovation Initiative	Funding Type	Project Cost	Benefit	Saving Projection DPCR5	Benefit/ Saving RIIO ED1
Safety/Investment Planning - Polymeric Investigation - Forensic Investigation of failed and new insulators	IFI	£56,000	Improves the reliability of high voltage switchgear	-	Ongoing requires quantification
Network Planning - Harmonic Cabling Modelling – Analysis of the technical requirements for the connection of non linear loads	IFI	£9,000	Allows the connection of higher levels of generation without network reinforcement	Avoided Costs	Avoided Costs
Investment Planning - Stay Rod Testing - Non intrusive testing of below ground structures	IFI	£17,000	Testing completed and proved inconclusive and therefore will not proceed, alternative techniques will be investigated	-	-
Network Protection and Control - Fit Calibrate HAT's - Forensic investigation of network load measurement systems	IFI	£24,000	Allows more targeted investments and facilitates connections based on available information	-	Qualitative
Network Performance - Nafirs - Academic Investigation of fault data	IFI	£27,000	Used to develop Quality of Supply Investments and their likely effectiveness	-	Qualitative
Stakeholder priority - Affordability					
Investment Planning - Expansion Planning V2 – Development of network models for demand forecasting and pricing	IFI	£372,000	Allows more targeted investments in reinforcement for load growth	-	Qualitative
Network Design - Earthing - Investigation of transfer potential under fault conditions	IFI	£5,400	Reduces investments in underground electrode systems	-	Qualitative
Network Operation/Design - Fault Current Limiter - Development and installation of a super conducting fault current limiter	IFI	£540,000	Avoidance of network reinforcement to mitigate fault levels exceeding equipment safety ratings	-	£3m
Safety/Investment Planning - OLTC Monitoring - Acoustic monitoring of OLTCs	IFI	£277,000	Enhances safety of operatives following high profile OLTC failures and is also used to assess health of asset for more targeted investments	£750k	£500k
Network Capacity - Dynamic Line Rating - Weather related overhead line ratings	IFI	£323,000	Allows the connection of wind turbines to remote overhead lines	-	Avoided Costs
Network Capacity - Storage - Defining the economic and regulatory benefits of energy storage	IFI	£183,000	Facilitates the connection of low carbon technologies allowing demand management	-	Qualitative
Network Planning - Load Related Risk - Development of load-related output measures to succeed the current Load index (LI) methodology	IFI	£20,000	Allows more targeted investments in reinforcement for load growth	-	Qualitative
Stakeholder priority - Sustainability					
Demand Side Management - DSM Signals - Assessment of DSR price signals	IFI	£15,000	Understand benefits of ENWL's Low Carbon Network Tier 2 project, C_2C-realised through avoiding investment in network reinforcement and Demand Side Response	-	£10m
Network Capacity - Load Allocation - Development of software to project and identity overloads due to the projected take up of low carbon technologies	IFI	£460,000	Improved modelling of inherent capacity on the network as required by local conditions of increased demand and generation	£1m	£600k

Delivering innovation in reliability

Knowing when to invest in replacing, refurbishing or retiring our assets has a fundamental effect on the reliability of our network and the quality of service experienced by our customers.

8.25 We have developed best practice asset management strategies through the development of Condition Based Risk Management and Condition Data Capture, which allows greater visibility of the health of our assets. Once we understand the health of our assets we can then determine the appropriate intervention and investment required. We have led the industry in pioneering this approach and it is now widely used and referenced by all DNOs.

8.26 CBRM helps us develop whole life asset management strategies based on analysis of current and expected future performance. We have invested £500,000 in this initiative so far and have realised approximately over £50 million in benefits through cost and delivery efficiency and scope optimisation. CBRM is now a business-as-usual activity and has played a major part in supporting our business plan.

8.27 With our partners the University of Manchester, we researched the benefits of in-situ oil regeneration for our transformers. We can now regenerate transformer oil on-site through this pioneering technique, reducing the need for removal and replacement and significantly extending the operating lives of our transformers. We have used the IFI investment of £215,000 to defer significant non-load related investment during RIIO-ED1. In RIIO-ED1 we plan to use this technique to avoid the replacement of over 12 Grid and 77 Primary transformers, which will save customers an estimated £33 million.

8.28 We have worked extensively with local police forces and specialist security advisors to develop a number of innovative techniques to complement more traditional security strategies in order to secure our network and reduce the number of customers suffering supply interruptions due to criminal activity.

- Metal theft – A marking system for copper earth tapes and cables that allows positive identification of the materials rendering the materials extremely difficult to dispose of without detection
- Active tracking – New technology adapted from military applications where tracking devices are attached unobtrusively onto most types of substation assets and materials. The equipment can then be monitored and tracked when moved, allowing recovery from theft
- Security hardening – A number of initiatives specifically targeted to limit the impact of theft at substations including a £3.2 million implementation of new electrical mechanical locking systems across 500 sites to prevent illegal access to secondary network substations

Innovation in sustainability

We play a lead role in the Smart Grid Forum and development of the Transform model that is used by all Distribution Network Operators. We have also used IFI funding to develop a more granular network capacity management model.

8.29 We call this the Capacity Headroom model. This model supplements Transform and allows us to understand how our customers use our network now and forecasts the future impact of adopting Low Carbon Technologies such as electric vehicles and heat pumps at an LV individual feeder-by-feeder level. Whilst this model tells us where our load carrying capability has to increase we also use it to more accurately target our future requirement for network reinforcement solutions. This ensures that we can deliver low carbon solutions whilst minimising the cost of network reinforcement for our customers.

8.30 Our stakeholder engagement has clearly shown that in order for customers to adopt these new Low Carbon Technologies, the connection experience must be streamlined and simple. We have led the ENA heat pump and electric vehicle group to implement customer-friendly connections processes.

8.31 We have developed Demand Side Response (DSR) solutions to ensure we can support more sustainable technologies whilst maintaining reliability and affordability. DSR involves customers agreeing to shift their consumption patterns away from times of peak demand. This gives us more options to optimise load capacity and less reliance on reinforcement work. We anticipate that this could save £10 million in reinforcement costs through RIIO-ED1 under the DECC Low scenario.

8.32 During 2012 we worked with the Met Office and other DNOs on the EP2 project to assess the potential impact of climate change on electricity networks. On average 20% of all faults on the low voltage overhead network are related to tree-induced damage. Using Met Office projections relating to the future effects of temperatures, we commissioned work on future vegetation growth rates in defined UK bioclimatic zones.

8.33 The outcome of this research allows us to produce mitigation measures and accurate expenditure forecasts for tree cutting, flood resilience and erratic electricity demand fluctuations attributable to climate change. This means customers will benefit from greater network reliability and reduced asset replacement costs.

Innovation in affordability

The cost of connecting to our network can be prohibitive for some customers. We have invested in the development of innovative commercial arrangements under our LCNF Capacity to Customer (C_2C) programme to make this service more affordable.

8.34 New commercial arrangements allow customers to connect to the network using latent network capacity and offer voltage managed contracts for Distributed Generation customers. The real-time network voltage is used to control the use of existing assets, enabling us to minimise the connection costs of new generation connections. We are the first DNO to enter into these types of commercial arrangements with customers.

8.35 We recognise that developing solutions to address fuel poverty and help our vulnerable customers is extremely important. We have been working with a range of charities and government bodies to truly understand the issues around fuel poverty and how we as a DNO can make a positive difference. We have worked with Save the Children and National Energy Action (NEA) and have hosted a working dinner on fuel poverty with MPs from the North West at the Houses of Parliament.

8.36 We have implemented Connect and Manage strategies for low voltage domestic micro generation such as solar panels. In Stockport we transformed our processes for connecting large numbers of solar panels on the roofs of social housing by introducing this Connect and Manage approach. This reduced costs for Stockport Council considerably, as it negated the need for costly and time-consuming investigations into scenario and load planning. Instead, we simply connected all the solar panels, deployed inexpensive LV monitoring and dealt with a very small number of resulting problems. The trial was so successful that this Connect and Manage approach has replaced our existing process for all solar panel connections.

8.37 We are currently conducting a feasibility study with NEA and Stockport Council on an innovative project to get their social housing stock and tower blocks fit for the 21st century. Rather than spending more money to strengthen the electricity network for social housing through costly reinforcement works, we have taken the innovative approach of improving the energy efficiency and insulation of the properties instead. The energy efficiency reduces the amount of energy required to run the properties and therefore reduces the need to reinforce our network.

8.38 We will trial this approach later in the year alongside other techniques for reinforcement avoidance such as Demand Side Response. NEA believe that this sort of innovative approach not only saves money, and is environmentally friendly, but more importantly directly helps those most in need of support by reducing household energy bills.

8.39 In May 2013 the first stage of a new initiative to become a Smart Energy Community was successfully completed by Wigton in Cumbria. The initiative addresses fuel poverty by putting in place wirelessly-operated smart meters, which provide residents with more visibility of their energy usage to help them control what they use, allowing them to reduce their bills and save money. The first stage enabled the town to control their energy and share findings with the hope of expanding the trial to more homes and businesses in the future.

Innovation in customer service

Analysis of the performance of our low voltage network revealed a disproportionate impact on our customers from transient faults. These are intermittent faults that disrupt customers' supplies but have no identifiable cause and can occur a number of times before the fault is identified and repaired.

8.40 To solve this problem, we have worked with Kelvatek, a technology manufacturer, to develop a number of devices such as the Modular Re-Zap (a unit that switches loads on low voltage networks) and the Bidoyng smart fuse (a device that can automatically restore customer supply in under three minutes).

8.41 These devices have transformed the management of LV network cable faults. We will continue to implement this technology on our network and assist other DNOs by passing on our learning. Our £400,000 investment has resulted in over £2.3 million of price reductions on equipment purchases from our suppliers, a benefit that is passed on to our customers through cost reductions and improved supply.

8.42 Almost 50% of the visitors to our website used a smart phone or tablet to access key pieces of information and over 25% of our website visitors access our website specifically looking for power cut information. With customer input we have developed a mobile-friendly website that fits customer needs by giving customers accessibility irrespective of the mobile device they are using. This is ideal when customers are looking for information during a power cut and the use of a desktop is not an option.

8.43 During 2014, mobile internet use is expected to take over from desktop internet use, making this service crucial to enhancing our customers' interactive experience with us.

Collaborating for innovation

We recognise that we cannot lead on every issue but we are committed to continue the progression of innovation within our industry through collaboration with partners and leadership of national industry forums.

8.44 This role allows us to deliver more value for our customers by ensuring we are at the forefront of sharing best practice and have a position of influence regarding the future needs of our customers and stakeholders.

8.45 The national industry forums we participate in include:

- The DECC and Ofgem led Smart Grid Forum and the Electricity Networks Association (ENA) Futures Group. The Smart Grid Forum is focussed on identifying future challenges for electricity networks, system balancing and removing barriers to the efficient deployment of smart meter and smart grid technologies. This group's work is at the heart of shaping the future decision making and strategic direction of our industry
- We lead the ENA Heat Pump Working Group and ENA Electric Vehicle Working Group. These groups are working closely with manufacturers, installers and other stakeholders to agree on standard UK approaches for heat pump and electric vehicle charger installations
- We chair the Distribution Code Review Panel and through this we have introduced new customer friendly Connections Standards for renewable generation

8.46 We have also collaborated closely with local and national groups to drive innovation:

- The Greater Manchester Combined Authority (GMCA) to prepare for a number of planned heat pump installations stimulated by the Renewable Heat Incentive
- UK Distribution Network Operators through the Strategic Technology Programme (STP) operated by EA Technology and the Energy Innovation Centre. Electricity North West currently hold the chair of the STP Board and use this position to support EA Technology to identify and develop a range of new projects for UK DNOs, including identifying areas of common interest, identifying new asset management techniques, development of new testing techniques and investigation of future trends in low carbon technology adoption

8.47 In addition to these groups we have worked with a network of individual organisations developing innovative solutions for specific problems. Examples include regular knowledge sharing sessions with Liverpool and Manchester Universities, where we define our needs and they explore potential innovative solutions based on their expertise. We also have partnerships with Durham and Strathclyde Universities. Furthermore, we have a number of collaborations with other DNOs and National Grid to drive development of industry best practice.

Our innovation plan

Our innovation plan for RIIO-ED1 needs to adapt to an unpredictable future and we have identified key areas of innovation investment rather than being constrained by specific project definitions.

8.48 Whilst much of our innovation has and will continue to come from within our organisation as a direct response to changing customer needs, it originates in our contacts with manufacturers or as a result of collaboration with other network operators and technology suppliers. Our focus will continue to be on developing innovative solutions which deliver tangible, positive benefits for our customers and stakeholders. In some selected areas such as storage, we will continue to be a fast follower where we will adopt best practice solutions developed by other DNOs as well as continuing to lead at industry level to help create and share innovative ideas for the benefit of all.

Delivering innovation in RIIO-ED1 2015 - 2019

8.49 During this period we expect increasing customer demand and the clustered connection of Low Carbon Technologies to push local network capacity to its limits. We will focus on understanding in greater detail the capability of our network to expand and meet demand increases whilst maintaining exceptional levels of reliability and customer service.

8.50 We will use innovative approaches to provide more from our current network:

- Focus on the collection of real-time data on network performance, capacity and load from automated data capture, including data from smart meters
- Use our Capacity Headroom Model to identify and quantify network capacity and identify areas of strain on our network in real time
- Progress development of technologies currently in research through continued collaboration with our partners to achieve our stakeholder priorities
- Develop and invest in our employees' core skills in the areas of commercial, financial and technical innovation
- Focus on the delivery of priority services for vulnerable customers and those affected by fuel poverty
- Continue our leadership in industry forums and working groups

8.51 We have combined learning from several pieces of research work from the EATL Strategic Technology Programme (a collaborative research group involving all network operators which we chair). This has led to the incorporation of innovative ideas using research undertaken by EATL and by other DNOs with our own developments to give direct customer benefits such as strategies for low voltage domestic micro generation such as solar panels.

8.52 Work undertaken by WPD was extremely useful in developing the various trigger levels in our policies below which it was not necessary to put reinforcement in prior to connection. This allows domestic customers to connect solar panels at a lower cost. Our social housing stakeholders such as Wigan and Leigh council and Stockport homes have welcomed the savings this brings and the speed at which it allows them to install solar panel equipment.

Delivering innovation in RIIO-ED1 2019 – 2023

8.53 Our focus in this period will be the delivery of our data strategy and use of smart meter information to drive further efficiency, reliability and low carbon capacity on our network:

- Micro level data management of network performance

- Move from research and development to industrialisation of developed technologies
- Integration of smart meters into control room systems
- Response to stronger market demand within RIIO-ED1 for DSR and an increased requirement to manage network constraints and balance network supply
- Development of RIIO-ED2 investment plans based on real time data and Demand Side Response outputs
- Roll-out of Smart Grid solutions supporting the increased level of heat and transport load on our network

8.54 The development of smart grids is being championed as a key facilitator in the transition to a low carbon, low cost, greener future for Great Britain. In Annex 13, we outline our vision of a smart grid in Electricity North West and point to a number of key activities and work areas which are contributing to the development of the future distribution network.

8.55 Smart Meters will be installed in the homes and businesses of our customers over the next few years. These devices will help our customers realise savings and benefits never before available. As our customers' usage of and reliance on electricity increases, smart meters will become a vital part of our network management infrastructure.

8.56 Annex 28 outlines how we will use smart meters to improve our services and deliver savings to our customers. As the meter installation programme gathers pace our initial challenge will be to assist electricity suppliers in ensuring customers receive a safe and trouble free transition to the new meters. In parallel with this installation programme we will upgrade our IT systems to be able to use the meter data for the benefit of our customers.

8.57 This IT upgrade programme has already started and to ensure we deliver benefits as soon as possible we have commenced several elements of this work in DPCR5. We are also working with electricity suppliers to ensure customers are properly informed about both the installation programme and the benefits on offer.

Funding our RIIO-ED1 innovation plan

We are requesting a Network Innovation Allowance of 0.8%. This equates to a total value of £23.5 million for RIIO-ED1.

8.58 In DPCR5, we will spend an average of £3.3 million per annum on innovation. This business plan contains a 10% reduction in innovation investment but a significant increase in benefits delivered for customers arising from two factors.

- First, we anticipate that more learning will be available from the wide range of projects being delivered by other DNOs or developed collaboratively with other partners. This allows us to identify and implement best practice solutions without the cost burden of extensive research and development being passed on to our customers
- Second, we have already funded a number of innovations from the efficiencies they yield in our expenditure plans, such as Connect and Manage and our work on promoting energy efficiency. We will continue to utilise this approach in RIIO-ED1

8.59 Funding from the Innovation Roll-out Mechanism (IRM) will also allow us to deliver RIIO-ED1 innovations with our partners for our stakeholders. We are committed to sharing our knowledge and experience with other DNOs through our continued chairmanship of and contribution to industry forums and working groups.

8.60 We also understand that we may not be able to predict the scale and complexity of future innovations. For larger scale innovations we will apply for additional funding through NIC with our partners.

8.61 The diagram below sets out the key areas of focus for the innovation programme, their forecast profile and expenditure.

RIIO-ED1 innovation initiatives

Average annual spend - £2.96m			2016	2017	2018	2019	2020	2021	2022	2023	Projected Project Expenditure (£m)
Reliability	Load impact modelling	LV									0.8
		HV									
	Thermal capability	LV									1.2
		HV									
	Asset management	LV									1.2
		HV									
Affordability	Network configuration	LV									1.2
		HV									
	Reference networks	LV									1.2
		HV									
	Network modelling	LV									1.7
		HV									
	Feeder operational modes	LV									1.2
		HV									
Sustainability	Voltage management	LV									2.0
		HV									
	Feeder design	LV									1.5
		HV									
Customers	Demand side management	LV									2.0
		HV									
	New connections	LV									1.2
		HV									
	High performance computing/ data manipulation	LV									0.8
		HV									
	Automatic fault restoration	LV									1.2
		HV									
	Distribution System Operator services	LV									0.8
		HV									
Commercial	Data clouds	LV									1.2
		HV									
	Development of autonomy	LV									1.5
		HV									
Assets	New materials	LV									2.9
		HV									
Total											**23.6**

9 Glossary

AA1000APS	AA1000 AccountAbility Principles Standard. An international standard to help organisations identify, prioritise, and respond to sustainability challenges
Affordable	That can be afforded, inexpensive and reasonably priced
AGMA	Association of Greater Manchester Authorities
AMI	Advanced Meter Infrastructure
Asset management	A systematic and cost-effective process of operating, maintaining, upgrading and disposing of assets
BCF	Business Carbon Footprint. The measure of the carbon emissions of our business
BITC	Business in the Community. Campaigns for and supports businesses to operate responsibly
Black Start	A restart of the electricity distribution and/or transmission network after a complete loss of power
BMCS	Broad Measure of Customer Service
BSI	British Standards Institution
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model. A mathematical model for determining a company’s Cost of Equity
CBA	Cost Benefit Analysis. Systematic process for calculating and comparing benefits and costs of a project or investment decision
CBRM	Condition-Based Risk Management. The creation of an effective link between information and knowledge of assets to strategic planning and processes
C_2C	Capacity to Customers (a Low Carbon Networks Fund project)
CDC	Condition Data Capture. The collection of condition data on our assets
CEPA	Cambridge Economic Policy Associates. Economic and financial policy advisory business
CEVA	Our contracted logistics provider to April 2014
CGU	Cash Generating Unit
CI	Customer Interruption. The number of customers interrupted per 100 customers
CLASS	Customer Load Active System Services (LCNF/future networks project)
CNI	Critical National Infrastructure
CO_2	Carbon Dioxide
Competition Tests	Tests introduced by Ofgem into DNOs’ licences at the start of DCPR5 to assess compliance with legal requirements in respect of the making of connections and to measure the development of competition in relevant market segments of the connections market. Passing these tests allows a DNO to charge an unregulated margin for contestable connections activities; not passing them could result in Ofgem referring a DNO to the Competition Commission
Competitive connections	Connections that can be completed by Third Party Providers, not just Distribution Network Operators
CORD	Central Oil Reprocessing Depot
Cost of Debt	The effective rate that a company pays on its debt.
Cost of Equity	The effective rate that a company pays to its shareholders.
CPNI	Centre for the Protection of National Infrastructure

CRM	Customer Relationship Management
CSR	Corporate Social Responsibility
Customer	A stakeholder who pays for a service that we provide
DCC	Data and Communications Company. The entity that will coordinate communications between smart metering equipment in domestic consumers' homes and authorised smart metering data users.
Decarbonisation	The reduction or removal of carbon dioxide from a process
DECC	Department of Energy and Climate Change
Defra	Department of Environment, Food and Rural Affairs
Delivery model	The resource mix and execution strategy selected to deliver the desired business outcomes
DG	Distributed Generation. Generation connected directly to Electricity North West's network rather than through National Grid
DLO	Direct Labour Organisation
DNO	Distribution Network Operator
Domestic Renewable Heat Incentive	Government-funded initiative. The world's first long-term financial support programme for renewable heat, launched in 2011
DPCR4	Distribution Price Control Review 4, 2005-2010
DPCR5	Distribution Price Control Review 5, 2010-2015
DUoS	Distribution Use of System
EHV	Extra High Voltage (usually 33kV in our region)
ELT	Executive Leadership Team
ENA	Energy Networks Association
ENWL	Electricity North West Limited
ENWSL	Electricity North West Services Limited (formerly United Utilities Electricity Services)
ESG	Environment, Social and Governance
ESQCR	Electricity Safety, Quality and Continuity Regulations (Amended)
ETR138	Engineering Technical Report 138. Resilience to flooding of grid and primary substations
Fast pot / fast money	Costs which can be partially or wholly recovered in the current period rather than being added to the regulated asset value and recovered over a long period
FIT	Feed-In Tariff. Price at which energy suppliers buy energy from Distributed Generation.
FFO	Funds From Operations
Framework contractor	A contractor with whom we have a long term agreement to carry out work at a pre-agreed price and under pre-agreed terms and conditions
Frontier Shift	Productivity improvements industry made possible by new technology and ways of working
Fuel poverty	A household which needs to spend more than 10% of its income to heat the home to an adequate standard of warmth is classified as fuel poor
Fugitive emissions	Release of greenhouse gasses as a result of leakages or accidental releases. In the context of Electricity Northwest this mainly refers to SF_6 emissions
GIS	Geographic Information System
GSoP	Guaranteed Standards of Performance. Standards set by Ofgem which must be adhered to by every Distribution Network Operator

HI	Health Index
HV	High Voltage, 6.6kV or 11kV in our area
HVCA	High Volume Call Answering
IAASB	International Auditing and Assurance Standards Board
iBoxx	The iBoxx bond market indices are benchmarks for professional use and comprise liquid investment grade bond issues
ICP	An independent connections provider not affiliated to a distribution network operator
ICS	Institute of Customer Service
IDNO	Independent Distribution Network Operators own and operate various small networks embedded within DNO networks. IDNO do not have a defined distribution service area
IET	Institute of Engineering and Technology
IFI	Innovation Funding Incentive
Investment Grade	A credit rating that indicates that the rated instrument has a low chance of default. Many investors will only buy bonds that have an Investment Grade credit rating and Ofgem requires us to maintain our credit rating at BBB and Baa3 level
ISAE 3000	The ISAE 3000 (2003) is the International Standard on Assurance Engagements. This is a recognised international standard to ensure the quality of assurance work, including report verification, as well as, assurance on environmental performance, corporate governance, internal compliance, stakeholder engagement and other areas central to corporate responsibility
ISO 14001	International Standard for Environmental Management
ISO 31000	International Standard for Risk Management
kV	Kilovolts
kVh	Kilovolt hour
LCNF	Low Carbon Networks Fund
LI	Load Index
LCT	Low Carbon Technology. Technology which is developed to substantially reduce carbon dioxide emissions
LLP	Limited liability partnership
LRRM	Losses Rolling Retention Mechanism
LV	Low Voltage, 6.6kV or 11kV in our area
MWh	Megawatt hour
NGET	National Grid Electricity Transmission
NGO	Non-Governmental Organisation
NEA	National Energy Action
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NMS	Network Management System
NTR	Non Trading Rechargeable
NuGen	A UK nuclear company owned by GDF SUEZ and IBERDROLA. NuGen's Moorside project is a new nuclear power station of up to 3.6 GW on land in West Cumbria, North West England
NWEN(J)	North West Electricity Networks (Jersey) Limited
Ofgem	Office of Gas and Electricity Markets

Ofgem strategy decision for RIIO-ED1	Decision document which sets how DNOs will be regulated during RIIO-ED1
OHSAS 18001	Occupational Health and Safety Advisory Services 18001. A health and safety management system certification
OLTC	On-Load Tap Changer. A device which allows us to adjust the secondary (output) voltage of a transformer while it is under load
Opex	Operational expenditure
PAS-55	Publicly Available Specification 55. An asset management certification. Provides guidance and certification for good practices in asset management. Electricity North West has been certified since 2007
Pass-through costs	Costs outside our control, such as taxes, insurance and rates which we pass through directly to suppliers
PFI	Private Finance Initiative
Photovoltaic cells	Cells that convert solar energy into electricity
Planned outages	Scheduled power cuts to ensure vital maintenance work can be carried out on the distribution network
PMICR	Post-Maintenance Interest Coverage Ratio. A financial ratio which measures how much money we have available to pay our interest expenses after essential spending on our network
PSR	Priority Services Register. A database of vulnerable customers who require extra assistance during power outages
QoS	Quality of Supply
RAV	Regulatory Asset Value
RCF	Revolving Credit Facility
Reliable	Able to be trusted; predictable or dependable
Relevant market segment	Ofgem defined nine connections market segments that covered demand, distributed generation and unmetered connections where it was considered that competition in connections was likely to happen
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995
RIIO	Ofgem's new price control framework - Setting Revenue using Incentives to deliver Innovation and Outputs
RIIO-ED1	The first electricity distribution price review under the RIIO framework (2015-16 to 2023-24)
RIIO-ED2	The second electricity distribution price review under the RIIO framework (2023-24 to 2031-32)
RIIO-GD1	The first gas distribution price review under the RIIO framework
RIIO-T1	The first transmission price review under the RIIO framework
RPE	Real Price Effect. An increase in the real (adjusted for inflation) price of a particular good/service or basket of goods and services
RPI	Retail Price Index. A measure of inflation
SF_6	Sodium Hexaflouride – an insulating gas for switchgear that is also a potent 'greenhouse' gas
Slow pot / slow money	Costs which are added to the regulated asset value and recovered over time
Smart grid	A distribution network capable of dynamically routing energy to balance supply and demand
Smart meter	A meter that records electricity demand and can communicate demand to consumers, network operators and suppliers
Stakeholder	Anyone or any organisation that can affect or is affected by our network or our actions

Strategic wider works	This is a mechanism for considering and determining potential revenue adjustments during the price control period to enable the delivery of projects of larger strategic importance. It is usually applied to Transmission Network Operators such as National Grid but we will use it to deliver the network modifications required to support the new nuclear generating station in Moorside.
Sustainable	1. Capable of being sustained long-term. 2. Capable of being maintained at a steady level without causing ecological damage.
Totex	Total expenditure
tCO_{2e}	Tonnes of carbon dioxide equivalent
WACC	Weighted Average Cost of Capital
WSC	Worst Served Customer
WFR	Workforce renewal. To secure and develop the workforce of the future by setting workforce renewal targets for training and new apprentices
10-year trailing average	The average of the preceding 10 years

10 Annexes

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ANNEX 1: STAKEHOLDER METHODOLOGY AND RESPONSES

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Registered no: 2366949 (England)

Contents

1. Executive summary

1.1 Overview of our stakeholder engagement approach

The findings from our stakeholder engagement activity have helped shape our Well Justified Business Plan (WJBP). Our approach to engagement to help develop our plans complemented our existing engagement activities and processes.

Consulting specifically for our RIIO-ED1 plan, we focused our engagement on our plans up to 2023.

In line with our established approach to stakeholder engagement we:

1. identified relevant stakeholders for engagement;
2. defined the issues material to those stakeholders in relation to the business plan;
3. sought feedback from those stakeholders, on the issues material to them; and
4. responded to stakeholder feedback within our plan, and back to them direct.

To ensure that we understood stakeholders' views and had incorporated them correctly into our plans, we ran three complementary cycles of engagement.

Each cycle helped to refine feedback and ensure that we had interpreted them accurately. The main content of engagement to inform the business plan took place in Cycle 2.

Cycle 1: Preparation and introduction phase

Education and initial feedback through trial of innovative channels

Cycle 2: Main engagement phase

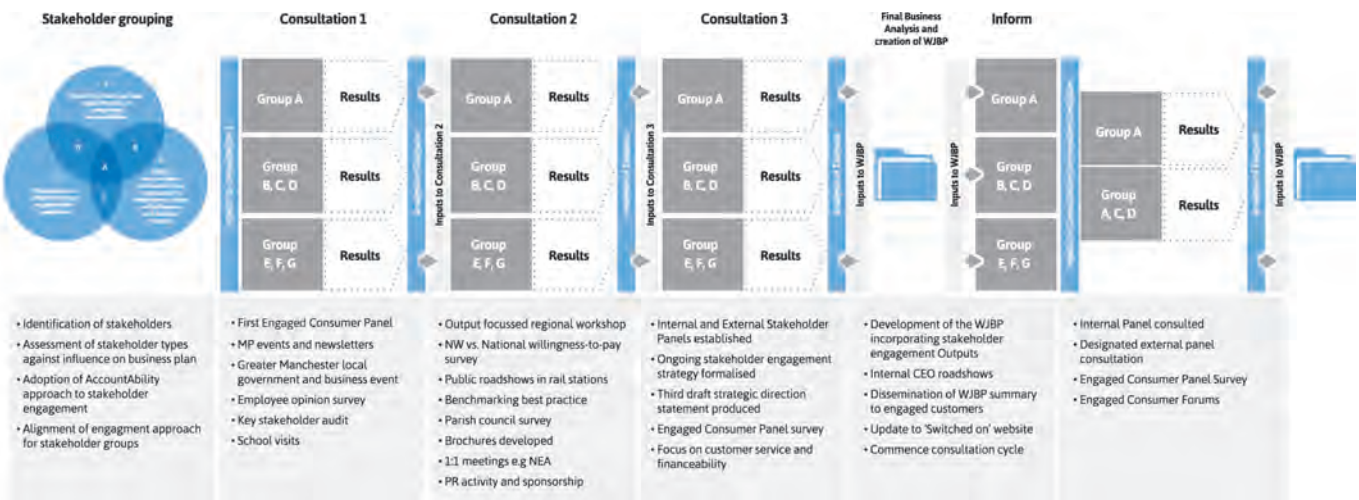
Refine focus of engagement. Bulk of testing with, and feedback from, stakeholders

Cycle 3: Analysis and evaluation phase

Final testing of our proposals with stakeholders for agreement

Additional Cycle

A further cycle of stakeholder engagement was carried out in early 2014 following feedback from Ofgem on our original plan. For more information on this additional engagement see section 5 of this annex.



2. Cycle 1 – Preparation and introduction

2.1 Purpose

The purpose of Cycle 1 was largely educational, including the establishment of a new campaign and brand identity: 'Switched On: North West'. This enabled us to set a framework for engagement, and make it clear to stakeholders the purpose and scope.

This preparation phase allowed us to set out how the next two cycles would develop.

We recognise that a clear barrier to engagement is a lack of knowledge about who we are and what we do among some stakeholders. To address this issue, we used this opportunity to trial new and innovative ways to engage stakeholders, including:

- getting more from school visits with take-home packs to engage parents;
- shopping centre roadshows with a new mascot and giveaways; and
- establishing a presence on social media.

This was complemented by a new campaign website, videos and online survey to attract stakeholders who may not otherwise have engaged with us.

Activity
Identified key stakeholder groups and channels of engagement
Created brand (Switched On) and mascot (Edison)
Create engagement website www.enwl.co.uk/switchedon
Establish social media presence (Twitter, Facebook, Youtube, LinkedIn)
Create educational videos (Who we are; Future challenges)
Full questionnaire available at www.enwl.co.uk/switchedon/have-your-say
Engaged consumer panel (February 2012)
Roadshows – shopping centres and business parks
School visits
Media analysis

2.2 Feedback, business analysis and outcomes

Successful channels of engagement with stakeholders were determined by the engagement team to take forward into Cycle 2.

Responses to questions at our roadshow events helped give an appreciation of topics concerning customers, however given the lack depth to these conversations the findings were inevitably restricted to high-level themes. Nonetheless, this helped shape our focus and engagement questions for Cycle 2.

Our online campaign site and questionnaire proved popular – and feedback from stakeholders showed an appreciation of its transparency, including the number of aspects that we must consider, and the impact of each on a customer's final bill.

Responding to stakeholder feedback, we developed a triangle of stakeholder priorities of:

- Reliability
- Affordability

- Sustainability

All delivered with exceptional customer service.

This focus helped direct our engagement during Cycle 2, and allowed stakeholders to plot themselves against the triangle to show where their priorities lay.

Feedback from Cycle 1 was fed back into the business to help develop the ED1 WJBP Executive Summary, with a separate 'What our stakeholders say' brochure developed setting out broad stakeholder views on each of the six key outputs. This brochure was then distributed to stakeholders and published online at www.enwl.co.uk/switchedon.

3. Cycle 2 – Main engagement phase

3.1 Purpose

The purpose of Cycle 2 was to continue the successful methods used in Cycle 1 using initial feedback from stakeholders to refine areas for discussion and establish detailed stakeholder responses.

The majority of feedback from stakeholders was gained in Cycle 2.

Activity
MP survey
2x MP events including engagement with National Energy Action and Professor John Hills as guest speaker on Fuel Poverty
UK-wide survey of domestic customer opinions to compare with results from NW customers
Stakeholder workshops across the region, bringing diverse stakeholder groups together to discuss issues raised in Cycle 1 in more detail and testing initial business proposals in reaction to Cycle 1 feedback
Further consumer roadshows with questionnaires (Rail stations and Business Parks)
Sponsorship of key publications – 100 years of Blackpool illuminations, Preston Guild official magazine, Cumbrian Newspapers to promote campaign and website
Third engaged consumer panel
Parish council survey
Engagement activity continued from Cycle 1: • Schools activity (Bright Sparks) • Public roadshow engagement activity • Social media outreach • Monthly Impact surveys of customers • Online questionnaire
Engage AccountAbility to assess stakeholder process and carry out gap analysis
Formalising stakeholder engagement strategy including plan to achieve stakeholder engagement assurance

3.2 Feedback, business analysis and outcomes

Stakeholder group	**Summary of feedback**	**How and where have we addressed this issue in the business plan?**
Domestic customers **Key areas** Reliability, affordability, customer service	**Reliability** of the network is the key issue for domestic customers. There is acceptance that faults can occur, but when they do **communication** and expectation management is very important. Providing for **vulnerable customers** is high on the list of priorities for domestic customers, including prioritised restoration if possible. Specific details about future planning is not high on domestic customers' priorities, although protection for events such as	Improving reliability Communication / customer service improvements Vulnerable customer strategy Reducing flooding impact through investment Safety campaign planned Planned outage timings to be reviewed

	flooding is. Wider **safety campaigns** are popular with domestic customers, as well as working with schools. There is a preference for **planned outages** to take place overnight or between 12pm-2pm. Preference to share **costs of network studies** between all customers prior to new connections as everyone benefits. Balanced approach to environmental risks preferred, including **oil capture** schemes and replacement of oil-filled cables. **Reducing bills** and **fuel poverty** seen as important by reducing demand and losses, leading to decreased need for new infrastructure to provide increased capacity.	Connect and m anage mitigates need for full network studies Oil-leak protection planned based on risk assessment Commitment to operational and communications measures to reduce demand, including work with National Energy Action.
Business customers (inc major customers) **Key areas** Reliability, affordability, customer service	All investment decisions we make should focus on i mproved **reliability**, this is the most important aspect for businesses. Better **information** about planned outages and during power cuts is important for business customers to enable them to plan effectively. Upsizing during **asset replacement** is important, but only where there has been a clear cost-benefit analysis. **Undergrounding for Visual Amenity (UVA)** is less important to businesses and m ajor customer than to NGOs or domestic customers – most businesses feel that undergrounding should only be done where it will improve **reliability**. If an area needs more **capacity** then the costs should be socialised, if a specific business needs more capacity then they should foot the bill. **DSR** is attractive but more information is needed and the price needs to be right.	Improved information about planned power cuts to customers Upsizing during asset replacement based on detailed analysis. Condition-Based Risk Management process also reduces cost Cost-share for capacity improvements and connections More information on D SR and pricing to customers. C2C trial pursued with thorough engagement with businesses on prices (www.enwl.co.uk/c2c)
Generation connectees **Key areas** Reliability, sustainability	There is a conflict between some groups and generation connectees. As the generators are commercial enterprises, some other stakeholder groups feel that they should pay for their own **network connections** or any **reinforcement** needed. The connectees feel that the costs should be s ocialised to encourage more connections, and because customers are benefiting from improved **security of supply**.	C2C
Local government (inc LAs, parish councils, sub-regional	Need to minimise investment to **reduce bills for fuel poor**. More should be done to **promote services for vulnerable customers**. Work with LA partners to identify vulnerable and get messages to them. Better **communication** with	Reduce prices in real terms Condition-Based Risk Management approach saves cost Vulnerable customer strategy

development bodies) **Key areas** Affordability, reliability, customer service	residents about who we are and what we do. **Undergrounding for Visual Amenity (UVA)** supported, but priority should be improvements to **reliability**. Could **rural areas pay less** as they have more power cuts? This would reduce need for costly improvements for low numbers of customers. Invest in **substation/asset security** measures, but not excessively.	Price difference depending on geographical location/number of faults not possible Balanced approach to security measures and based on level and impact of risk
MPs **Key areas** Reliability, customer service, affordability, sustainability	**Reliability** is key, a number of MPs see this as our only task. We should **communicate** more effectively with MPs and their constituents about who we are and how they can contact us, and issues specifically relevant to them. We should plan for the **future success** of the North West by looking at **capacity issues** to allow for growth. Work with **vulnerable customers** and exploring how we can reduce fuel poverty is important. We should keep our **substations** neat and tidy as they can have big impacts on communities.	Reliability improvements targeted More proactive and structured communications with customers and stakeholder C2C programme to reduce cost and speed of connections Vulnerable customer strategy Substation maintenance programme
NGOs (including regional single-issue groups) **Key areas** Affordability, sustainability	Single issue groups represent **fuel poverty** issues and a number of **environmental** matters. If we can improve energy efficiency or reduce consumption among domestic customers, then we will **reduce the need for reinforcement** saving us direct cost, and potentially removing people from fuel poverty. **Undergrounding for Visual Amenity (UVA)** schemes are seen as key by environmental groups with a request to extend the programme beyond National Parks, Areas of Outstanding Natural Beauty (NPs and AONBs). Can we consider design of poles and pylons in different areas that are more sympathetic to their environment. We should encourage **smart growth** to reduce need for more infrastructure. **Communication** is important as many groups may not know who we are or how our activities might affect them.	Addressing fuel poverty through partnerships with National Energy Action, British Red Cross and others as per Vulnerable Customer Strategy UVA conflicts considered in terms of cost. Overall beneficial to majority of stakeholders. Funding per year slightly increased but to remain on case-by-case basis in joint discussions with NPs and AONBs and other relevant stakeholders C2C and other innovation to enable smart growth Improved customer and stakeholder communication
Electricity suppliers **Key areas** Customer satisfaction, affordability	Suppliers view themselves as customers of ours and request premium **customer service**. They key output requested from the business plan is stability and predictability.	Customer service improvements for electricity suppliers Price impacts defined

This information culminated in the production of our 2013 strategic direction statement, focusing on our plans for 2015-2023.

4. Cycle 3 – Analysis and evaluation

4.1 Purpose

The purpose of Cycle 3 was to ensure that all relevant stakeholders were engaged on issues material to them and further test areas that require more information to allow us to adequately represent stakeholder views.

We issued the strategic direction statement developed from information gathered in Cycle 2 to all stakeholders previously engaged, and added a copy to our website. Further feedback was sought in key areas, and approval and endorsement of our final plans sought.

Cycle 3 also acted as a review stage to evaluate the engagement carried out with an opportunity to further formalise our ongoing stakeholder engagement activity. This included a third-party audit of our process to ensure its validity and trustworthiness.

Part of establishing this formal process included setting up both internal and external stakeholder panels. These panels reviewed our stakeholder engagement process and feedback, including how we have interpreted this feedback in relation to the business plan and how it has influenced our proposals.

These panels will remain in place up to and including the ED1 period to ensure that we remain focused on delivering what stakeholders want and need. The external stakeholder panel is encouraged to challenge both our plans and our processes to help us maintain robust and justifiable plans.

Key activity
Strategic Direction Statement published
First formal Internal Stakeholder Panel
First formal External Stakeholder Panel
All feedback from all stakeholders collated and reviewed
Further topics tested with stakeholder groups
Stakeholder engagement process assurance by Deloitte LLP
Formal endorsement of plans and business operations from stakeholders

4.2 Feedback, business analysis and outcomes

Testing the 2013 strategic direction statement with stakeholders gave an extra opportunity for stakeholders to comment on our plans before submission.

Our commitment of improved customer service and reliability for a reduced cost in real terms has proved popular with stakeholders.

Further engagement was requested from a number of stakeholders, up to and throughout the RIIO-ED1 period and we have committed to provide this.

Our revitalised framework for stakeholder engagement, developed in line with AccountAbility's Principle Standard, sets a solid basis for our ongoing future engagement.

The main feedback from stakeholders in Cycle 3 was that the outputs were largely correct, however we should focus on delivering it as efficiently as possible. Stakeholders want more for less.

We also acknowledge many stakeholders' views on reducing fuel poverty, including analysis of reports from DECC, National Energy Action and the Joseph Rowntree Foundation. As a result of this engagement – and research during Cycle 2 that showed that North West domestic customers the DE demographic were least willing to fund future investments in the network – we increased our focus on services for vulnerable customers, and have stretched our targets for efficient delivery, without compromising on outputs.

NEA: Fuel poverty in the context of wider energy policy (August 2012):

http://www.nea.org.uk/Resources/NEA/Policy%20and%20Research/Documents/Fuel%20Poverty%20in%20the%20Context%20of%20Wider%20Energy%20Policy.pdf

Joseph Rowntree Foundation: Tackling fuel poverty during the transition to the low-carbon economy (October 2011):

http://www.jrf.org.uk/sites/files/jrf/fuel-poverty-carbon-reduction-summary.pdf

DECC: Annual Report on Fuel Poverty Statistics (May 2013):

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/199833/Fuel_Poverty_Report_2013_FINALv2.pdf

5. Cycle 4 – additional engagement

5.1 Purpose

Following the submission of our plan to Ofgem in July 2013 and the subsequent feedback we received, our plans have been reviewed and resubmitted.

There were three aspects of our resubmission that we sought further stakeholder input on, to ensure that we are making the right decisions for stakeholders.

1. Changes to our original submission
2. New proposals
3. Further formal input and support of original plans

These three aspects cover the following main topics that we carried out additional stakeholder engagement on:

- **Connections** – should we change to our targets for time to quote and time to connect, and if so how?
- **Vulnerable customers** – we're adding more detail on what we're doing for vulnerable customers. Does it still reflect your views?
- **Storm compensation** – how do we get the balance right between compensating fairly and keeping bills down?
- **Electricity theft** – should we be doing more to tackle this issue on behalf of suppliers?

Activity carried out in Cycle 4

Key activity
Engaged consumer panel, January 2014
Extraordinary External Stakeholder Panel – RIIO resubmission, January 2014
Further formal endorsement from expert stakeholders

5.2 Feedback, business analysis and outcomes

Topic	Feedback	Outcome
Investment	While setting up our engaged consumer panel to tackle specific questions related to improving our business plan, we took the opportunity to continue to benchmark general willingness-to-pay in a number of investment areas. On average, engaged consumers are prepared to pay around £6 extra to fund network investment, although 36% were not willing to fund any additional investment. In terms of priorities, the panel told us:	We know that the priority for our stakeholders remains reliability. Providing support for our most vulnerable customers is also key. Stakeholders also believe that tackling electricity theft is important, along with many other issues. In balancing investment in these different areas we believe we are taking the appropriate steps and continuing to lead the industry. Engaged consumers, and our stakeholder panel also told us that they did not believe we needed such short times for

<table>
<tr><td></td><td>Reliability is still the main priority
Support for vulnerable customers is second most important
Reducing electricity theft comes 6th out of 11 options
Improving speed of connections is second lowest investment priority.</td><td>quoting or making new connections to the network. We have therefore responded and are proposing more appropriate and stakeholder-led targets.</td></tr>
<tr><td>Connections</td><td>Consumers can find it difficult to assess however given an open question, would prefer 7 days to quote and 13 days to connect
81% of engaged customers agreed with proposal to reduce targets but remain within top three performers
10 days to quote and 30 days to connect seen as acceptable to Consumer Futures.
Not particularly an issue for commercial customers due to longer project lead times.</td><td>Balancing these views, we are proposing to increase our original targets to six days to quote for a domestic connection and 30 days to complete a domestic connection. This still allows us to be market leaders, while reducing cost and risk to the business.</td></tr>
<tr><td>Vulnerable Customers</td><td>Consumers consider older customers, and those with medical needs to be most vulnerable.
Families with newborns also considered to be particularly vulnerable.
Most important support in order would be to:
upgrade the power network around hospitals and care homes
provide temporary power during outages
provide additional training for frontline staff
invest an additional £8m over and above current plans
contact all vulnerable customers once a year.
External panel commented that our approach is in line with other DNOs and stressed need for tailored services depending on vulnerability.
Investing in the network at key sites, and also contacting vulnerable customers</td><td>Following feedback from stakeholders we have decided to make our plans for vulnerable customers more specific and explicit. In doing this, we have increased our previous five outputs to seven.

In line with feedback from engaged consumers, we will:
keep proposal to upgrade the network at 56 hospitals and care homes
provide extra generation during outages
provide enhanced training for frontline staff
Feedback is clear that it is what we do, not how much we spend that is important to customers. Therefore we propose to focus on specific measures rather than spend levels.

We remain committed to contacting vulnerable customers regularly, however based on feedback and the balance of costs and service, propose to reduce our regular planned contact from ever year, to every</td></tr>
</table>

	regularly seen as important.	two years
Storm compensation	• Stakeholder panel recognise the difficulty in getting the balance right and suggested specific willingness-to-pay research with our Engaged Consumer Panel, however they did add that it is important for a DNO to maintain a level of discretion to consider appropriate compensation on each situation. • There is little appetite for increasing current compensation levels if it means increasing bills. • 70% of engaged consumers surveyed thought that £54 after 18 hours was reasonable if an outage was outside our control. • There was a relatively even split between engaged consumers who thought compensation should be paid at either 18 hours or at 48 hours following severe weather. • A third of engaged consumers are happy with current levels of compensation following severe weather, however almost half believe an extra £50 per day would be appropriate. • 88% of engaged consumers believe everyone affected should receive compensation, not just those who contact us. • 32% of engaged consumers surveyed believed that business customers should be compensated for total loss of earnings. 49% disagreed, and 19% did not know.	The majority of our engaged consumers told us that £54 after 18 hours without power due to a storm is about right. We agree, and despite there being an exemption available for severe storms that allows DNOs to only compensate customers after 48 hours, we have not used this exemption during recent severe weather events in December ‘13 and February ‘14. We’re planning on continuing with that approach, and consulted stakeholders to ask if we should never use the exemption. It is our intent not to use the exemption, however our stakeholder panel were keen for us to maintain an element of discretion. We considered the approach of some DNOs to simply double payments, however that still involves a trigger point at 48 hours. Our customers tell us that they want us to keep the trigger point for payments at 18 hours, meaning that we will pay more customers more compensation. Despite 32% of engaged consumers believing that business customers should be compensated for total loss of earnings, we believe the current arrangements are appropriate in order to remain affordable for all customers.
Electricity Theft	• Consumers appear keen for us to tackle electricity theft, even where the costs outweigh the financial benefits of doing so. However, there was some confusion highlighted by a consumer comment that it would ‘save money in the long run’.	We were one of the only DNOs to include information on electricity theft in our original plan. We checked with our stakeholders to see if it was something they really did care about, and they told us just what an important issue they think it is for us to tackle. As a result, we are committing to boost the

	• Consumers also recognised the safety as well as financial incentive to tackling the problem. • Although seen as important to tackle, our stakeholder panel recognise the need to draw a clear line where a DNO's social obligations must end due to costs to customers.	numbers in our revenue protection team in DPCR5, rather than waiting until RIIO-ED1. We have always been at the forefront of this issue for DNOs, and we will continue to promote our approach to Ofgem. Since we submitted our original plan in 2013, we are pleased to see that Ofgem has announced a new licence condition in RIIO-ED1 obligating all DNOs to follow our example in tackling electricity theft.

SUB-ANNEXES

A1. Stakeholder engagement strategy (from entry to Ofgem's 2013 stakeholder engagement incentive scheme)

A2. Deloitte LLP assurance statement

A3. Engaged Consumer Panel summary, February 2013

A4. Engaged Consumer Panel summary, December 2012

A5. Engaged Consumer Panel, North West vs National summary, June 2012

A6. Engaged Consumer Panel summary, July 2011

A7. Regional stakeholder workshops summary and slides, December 2012

A8. Parish council survey summary, December 2012

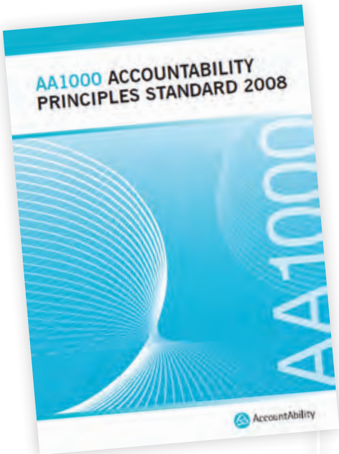
A9. Stakeholder report summary, July 2011

A10. Engaged consumer panel, full report, January 2014

A11. Extraordinary External Stakeholder Panel meeting minutes, January 2014

A12. Specific endorsement from key stakeholders

SUB-ANNEX A1: Stakeholder engagement strategy (from entry to Ofgem's 2013 stakeholder engagement incentive scheme)



1.2 Stakeholder engagement at Electricity North West

Stakeholders offer a huge source of knowledge and expertise. We rely on stakeholders, as experts in their fields, to inform our day-to-day and longer-term plans to help us meet their needs and expectations.

Our engagement is about continuous improvement and innovation. Allowing stakeholders to influence what we do and how we do it through structured and relevant engagement is essential to the successful operation of our business.

We worked closely with AccountAbility, a global think-tank and developers of internationally-recognised stakeholder engagement standard AA1000APS, to review our stakeholder engagement approach in 2012/13.

As a result of this work, we developed and launched a company-wide Stakeholder Engagement Manual, setting out a clear strategy with appropriate governance and structure, consistent operating procedures, and cohesive reporting and evaluation mechanisms.

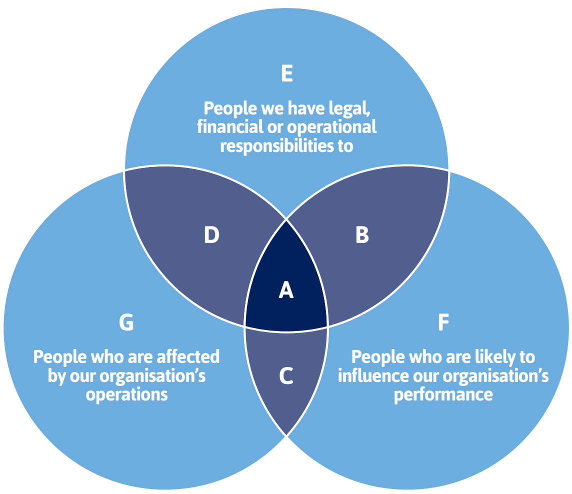
The manual is written as both a strategic guide and practical handbook for employees describing how engagement is done at Electricity North West. It was developed based on:

- ***our own best practice, including feedback from last year's stakeholder submission for Ofgem's Broad Measure of Customer Satisfaction;***
- ***benchmarking against best practice by other utilities and businesses; and***
- ***AA1000APS and direct consultancy from AccountAbility.***

1.2.1 Identifying stakeholders

The first stage of our robust stakeholder engagement strategy is to identify our stakeholders. We have developed our process for stakeholder identification into an objective framework, allowing us to review our existing list of stakeholders and add or remove stakeholders based on set criteria, ensuring consistency and fairness in selection and prioritisation. A set process for this element of our plan also removes the risk of the loudest stakeholder drowning out others.

Our list of stakeholders is formally reviewed internally every three months by our Internal Stakeholder Panel and every six months by the External Stakeholder Panel. For our latest list of stakeholders see the Stakeholder Engagement Manual (appendix 3).



1.2.2 Materiality determination process – what should we engage on?

Our second stage is to identify issues material to those stakeholders, and our own organisation. We have done this through a materiality determination process, resulting in a materiality matrix (below). This matrix forms the basis of the issues on which we engage, and allows us to apply a uniform approach to determining proportionality.

Inclusion of priorities in the matrix is influenced by three factors:

1. ***Feedback from stakeholders on what is important to them.***
2. ***Electricity North West's own five values: customer, people, safety, performance and innovation.***
3. ***Ofgem's key output areas for the next 10 years: reliability and availability, customer service, safety, environment, conditions for connections, and social obligations.***

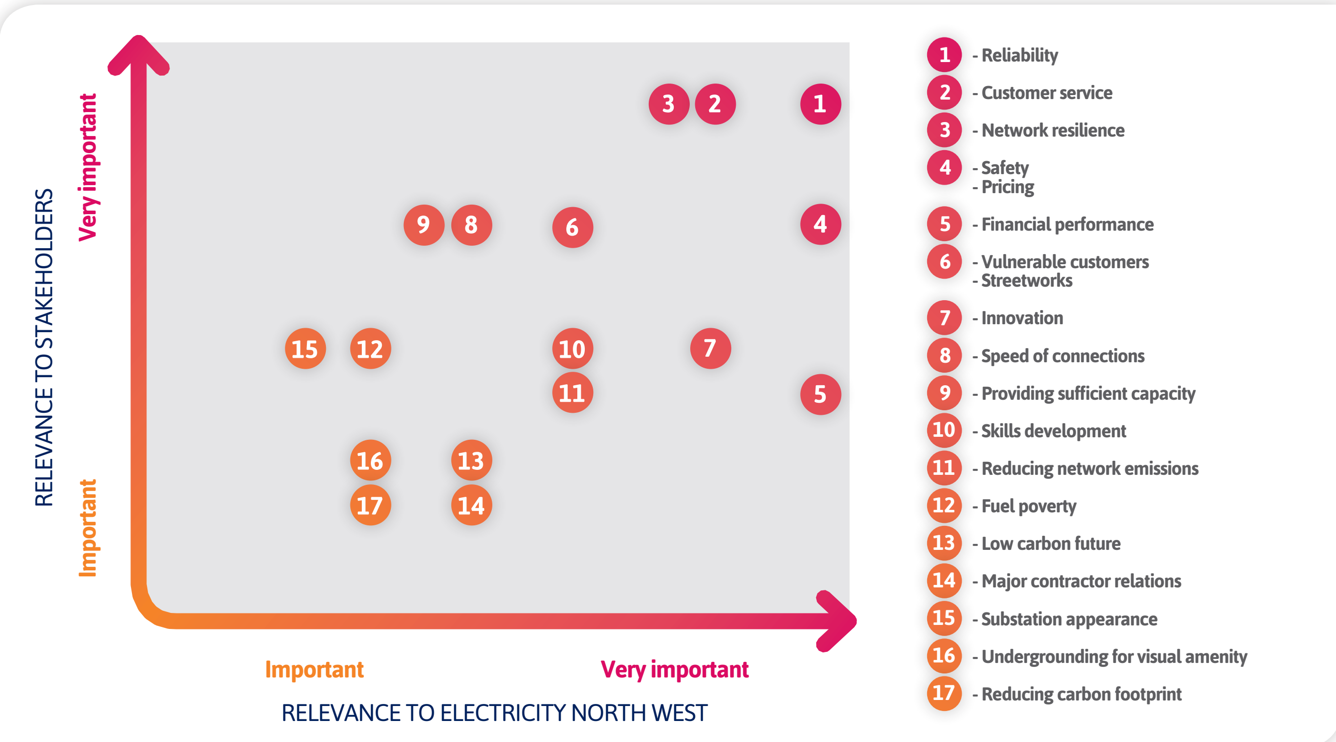
Using our corporate 'risk matrix' we have scored each priority against the risk of not including it, in terms of financial, legal, regulatory, health, safety, environment, people, reputation and security of supply impact.

We then multiplied this against a 'likelihood' score indicating the likelihood of the issue to have a major effect on our business in the next 10 years.

By categorising stakeholders in relation to how they are affected by, or affect our operations – using the stakeholder identification Venn diagram – we have been able to attribute appropriate and proportional weightings to their views.

Using these weighted stakeholder opinions, and also incorporating a calculation to incorporate the number of stakeholders affected, we have plotted relevance to stakeholders. The process and resulting table was then reviewed by both the Internal Stakeholder Panel and External Stakeholder Panel.

As with our stakeholder identification process, the materiality matrix will be reviewed by each panel at every meeting.



1.2.3 Responding to stakeholder feedback

Our third stage is to engage with those stakeholders on those issues relevant to them. One way we ensure that we do this is by simply asking our stakeholders which issues they would like to engage with us on, and how they would like to do it. This process of checking back with stakeholders is evident throughout our process, including External Stakeholder Panel feedback on our stakeholder identification and materiality determination.

The final stage is to report all engagement outputs, feed them into the business, record outcomes, and then report back to stakeholders on tangible changes to our business or plans as a result of their engagement.

Through our stakeholder engagement process, we know who our stakeholders are, what matters to them, and how they want to engage with us. We then tailor our approach based on this information – keeping them updated on relevant business activities, decision-making and other developments, but not wasting their time on things that are immaterial to them, or irrelevant to us.

In addition, we recognise that it is our job to balance stakeholders' sometimes-conflicting views to the satisfaction, or at least understanding, of all parties.

1.2.4 Engagement needs

The table below shows our high-level stakeholder groups, the need for engagement and examples of engagement in 2012/13.

STAKEHOLDER GROUP	ENGAGEMENT NEED	ENGAGEMENT IN 2012/13
Customers	Our customers include anyone who pays for our services, including domestic, business, connections and distributed generation customers. We need to listen to our customers' views to improve our operations and the services we provide for them.	• Ongoing customer service phone interviews • Willingness-to-pay surveys • Online feedback forms and web survey
Public sector	From local government and schools, to emergency services, MPs and national government – we have a number of key relationships and a vast range of public sector stakeholders. Engagement locally is essential due to the unique nature of our business which directly affects local communities. Engagement nationally as a regulated business is also essential, ensuring that we communicate appropriately at all levels and recognise our wider role in the UK.	• Regional workshops • Emergency planning meetings • MP events, survey and 1-1 engagement • Ongoing engagement through CEO's chairmanship of Energy Networks Association (ENA) • School liaison through BrightSparks educational programme
Industry	Our industry engagement includes engagement with electricity suppliers, employees, contractors and other utilities. By working together we can gain the benefits of a range of experience and viewpoints to help meet local and national stakeholder demands.	• Supplier meetings through ENA and our own 1-1s • Contractor forums • National Joint Utilities Group • Industry working groups
Non-governmental organisations	We interact with a number of NGOs, including environmental and other lobby groups. We have a local and national perspective to our responsibilities. For example, environmentally, we must manage our own direct impact with local stakeholders, and nationally we must continue to facilitate the UK's move to a low-carbon future. Stakeholders include Areas of Outstanding Natural Beauty, Friends of the Lake District, RSPB, National Energy Action, British Red Cross, Consumer Futures.	• Undergrounding for visual amenity quarterly group • External stakeholder panel • Regional workshops • Participation in stakeholders' meetings/workshops • 1-1 meetings
Financial	Our financial stakeholders, including our investors, banks and credit rating agencies, clearly have a big impact on our organisation. Appropriate engagement is key to the successful financing of our business.	• For more information see: www.enwl.co.uk/about-us/investor-relations • Regular meetings with banks and credit rating agencies to keep them informed

1.3 Relevant accreditation schemes and assurance

Our 2012/13 stakeholder engagement process has been independently assured by Deloitte LLP in accordance with the International Standard on Assurance Engagement 3000 (ISAE 3000 – a standard that has been designed by the International Auditing And Standards Board (IAASB) to assure non-financial data). (See Deloitte's assurance statement in appendix 1.)

We have systematically reviewed and revitalised our approach to stakeholder engagement throughout the year in line with AA1000APS. We are committed to the principles of inclusivity, materiality and responsiveness.

In 2012/13 we appointed a full-time corporate social responsibility manager (CSR manager), and entered the Business in the Community (BITC) Corporate Responsibility (CR) Index for the first time. The CR Index takes the form of an online survey where companies follow a self-assessment process intended to help them identify both the strengths in their management and performance, and the gaps where future progress can be made. BITC then independently validate submissions to ensure reliability and consistency.

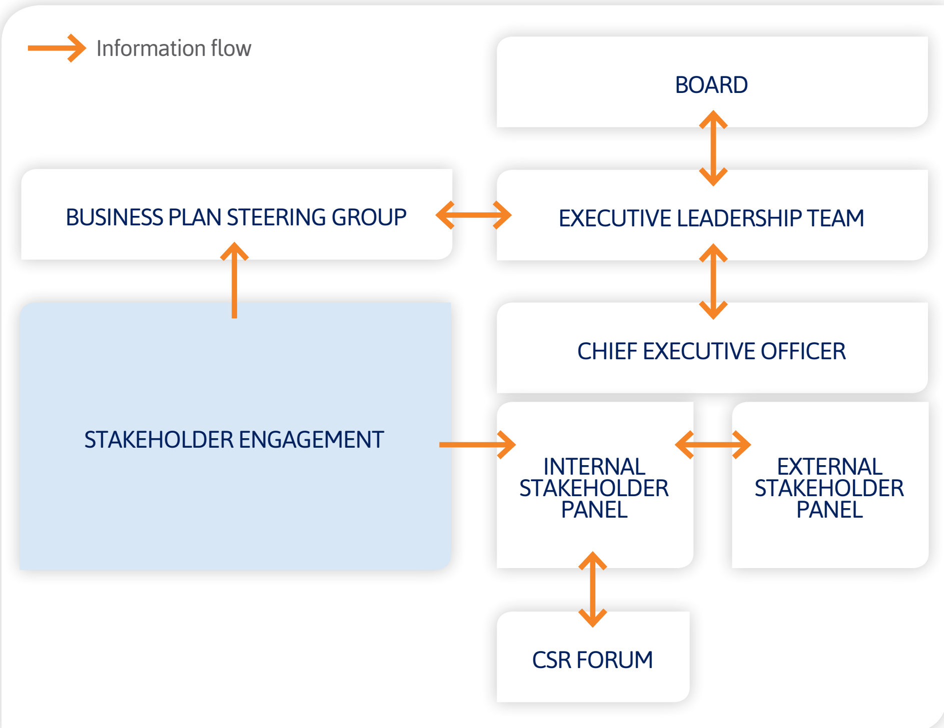
As in previous years, we also continued to report our CSR and stakeholder engagement activity against Global Reporting Initiative (GRI) guidelines. Our 2012/13 CSR report is due for publication in August 2013.

1.4 Evidence of culture change and senior management buy-in

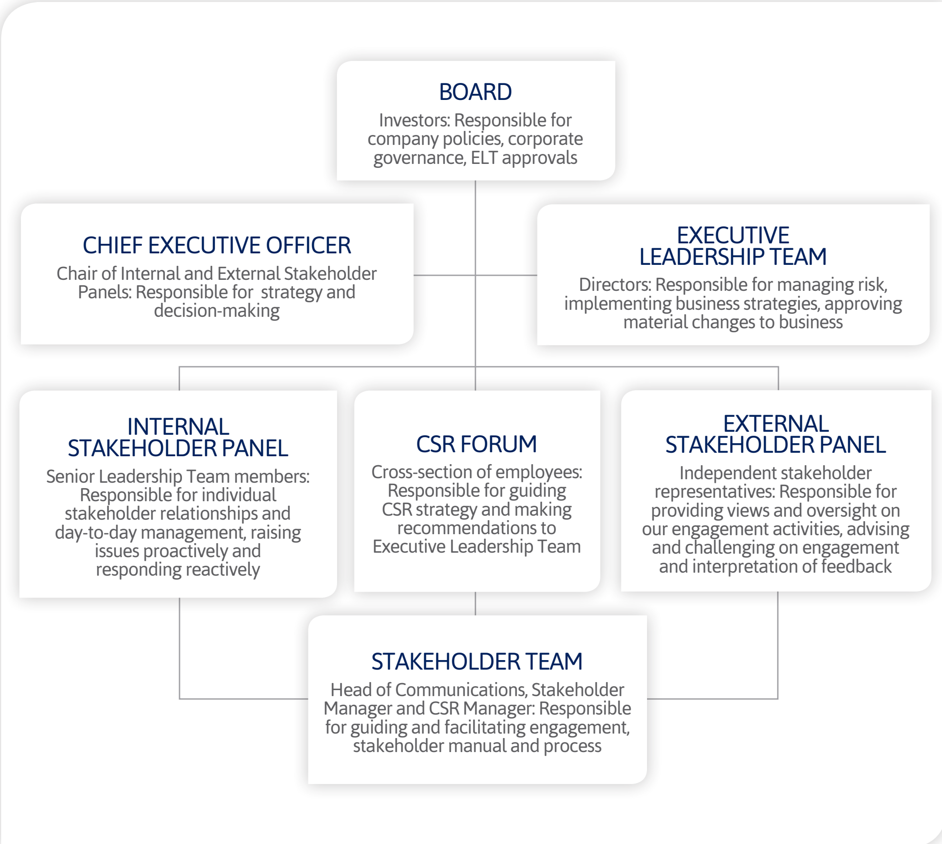
A strategy paper on our renewed approach to stakeholder engagement, including our commitment to follow the AA1000APS, was approved by our Executive Leadership Team in 2012 (included in Stakeholder Engagement Manual, appendix 3).

The overall governance structure of our stakeholder engagement activities is outlined below.

Governance structure and information flow:



Governance responsibilities:



Our new **Internal Stakeholder Panel** meets formally at least every three months to discuss stakeholder engagement issues. It is made up of 10 members of the senior leadership team, representing every business area, and is chaired by the chief executive officer, supported by the customer director and stakeholder engagement team.

The panel has its own terms of reference which are included in our Stakeholder Engagement Manual (appendix 3), and is responsible for developing and implementing the stakeholder strategy, including its integration into business processes and decisions. The decision-making process is aligned with our business model, and is described in detail in our stakeholder manual.

Our **External Stakeholder Panel** is attended by our chief executive, and although it purposefully has a level of autonomy, members of Electricity North West's senior management team are available to be called to attend the panel on request to present to or answer questions from panel members on topics of their choosing. Its terms of reference are also included in our Stakeholder Engagement Manual (appendix 3).

The internal and external stakeholder panels work closely together to complement each other and provide the right balance of responsibility from the internal panel and challenge from the external panel.

1.5 Results and feedback from stakeholder engagement

Our formalised framework for stakeholder identification has given our processes improved transparency and credibility. We have engaged with stakeholders at levels appropriate to their relationship with us and interest in issues concerning our organisation. Through a prioritisation technique we have ensured that our engagement is proportionate to each stakeholder.

In addition to our 'business as usual' stakeholder engagement, our 2012/13 stakeholder engagement activity focused on gaining feedback to help us develop our business plan for 2015–2023.

Based firmly on AA1000APS, our process continued to follow three cycles of engagement with stakeholders as we set out in 2011/12, wrapped up in the 'Switched On: North West' campaign.

Cycle 1

- ✓ Stakeholder identification
- ✓ key output and materiality determination
- ✓ first engaged consumer panel
- ✓ Greater Manchester local government and business event
- ✓ launch of first Strategic Direction Statement (2011)
- ✓ qualitative key stakeholder audit
- ✓ engaged consumer questionnaire
- ✓ MP events and newsletters
- ✓ Employee Opinion Survey
- ✓ Executive Leadership Team internal roadshows
- ✓ school visits; social media launch
- ✓ Switched On: North West branding and minisite launched (www.enwl.co.uk/switchedon)
- ✓ online willingness-to-pay survey
- ✓ educational videos produced
- ✓ first public roadshows.

PROCESS	KEY AIMS	KEY OUTPUTS
Stakeholder engagement	Identify, approach and inform stakeholders about the business, process for developing our plan and key output areas	Stakeholders clearly have differing views, and differing motivations and levels of interest. Challenge identified to ensure proportionality and materiality in all engagement. Further challenge identified in lack of knowledge becoming barrier to engagement.
Business decision-making	Are we addressing the areas that stakeholders want us to address? Are we engaging with stakeholders on issues that are material to them?	Focus on customer service and quality stakeholder engagement critical to all stakeholders. Plans must follow cyclical approach to keep stakeholders' interest. 'Engaged customer panel' concept developed to address accessibility issues.

Cycle 2

- ✓ Output-focused regional workshops
- ✓ second strategic direction statement produced
- ✓ North West vs National willingness-to-pay survey
- ✓ further public roadshows in key rail stations
- ✓ sponsorship of key publications
- ✓ increased promotional and public relations activity
- ✓ new process for highlighting types of work carried out with new 'communications for project managers' document rolled out
- ✓ 'What our stakeholders say' brochure produced
- ✓ 'How stakeholders are influencing our business plans' brochure produced
- ✓ Parish Council Survey
- ✓ further videos produced
- ✓ benchmarking engagement against other similar companies to identify best practice
- ✓ 1-1 meetings with key new stakeholders including National Energy Action.

PROCESS	KEY AIMS	KEY OUTPUTS
Stakeholder engagement	Elicit feedback from relevant stakeholders and customers on specific output areas to inform the plan.	Three-way challenge identified, to produce plan focused on affordability, reliability and sustainability.
Business decision-making	Develop business plan informed, proportionally, by stakeholder opinion, balancing conflicting views.	Customer-service focus of plan growing alongside asset management responsibilities. Key function of reliability reinforced – proper asset management fundamental in providing good operational customer service.

Cycle 3

- ✓ Internal panel established
- ✓ external panel established
- ✓ formal stakeholder engagement strategy developed and documented
- ✓ third strategic direction statement produced
- ✓ further engaged consumer panel survey focused on customer service and financeability
- ✓ industry-wide suppliers' engagement
- ✓ Independent connection providers workshop.

PROCESS	KEY AIMS	KEY OUTPUTS
Stakeholder engagement	Present interpretation of stakeholder engagement so far back to stakeholders for further feedback	Explaining conflicts helps stakeholders understand potentially difficult decisions we must make. Transparency key to credibility with stakeholders. ICP workshop to improve robustness of engagement with group.
Business decision-making	Are stakeholders happy with our interpretation, and how we have addressed their views in our plans? Is further engagement needed on any specific areas?	Commitment to continuing engagement with stakeholders during business plan period (2015-2023)

SUB-ANNEX A2: Deloitte LLP assurance statement

Independent assurance report by Deloitte LLP to Electricity North West Limited (ENWL) on the application of Electricity North West Limited's 2012/13 description of its 2012/13 stakeholder engagement programme for the reporting year ended 31 May 2013.

Scope of assurance work

We have been engaged by the Board of Directors of Electricity North West Limited to provide limited assurance[1] of ENWL description of its 2012/13 stakeholder engagement programme for the reporting year ended 31 May 2013 as found in sections 1.2.1, 1.2.2 and 1.2.3 of Sub-annex A1: Stakeholder engagement strategy (from entry to Ofgem's 2013 Stakeholder Engagement incentive scheme) of Annex 1: Stakeholder Methodology and Responses of ENWL's Well Justified Business Plan dated July 2013.

Basis of our assurance work and our assurance procedures

Our work was carried out by a multi-disciplinary team of corporate responsibility and assurance specialists in accordance with the International Standard on Assurance Engagements 3000 (ISAE 3000). To achieve limited assurance the ISAE 3000 requires that we review the processes, systems and competencies used to compile the areas on which we provide assurance. This is designed to give a similar level of assurance to that obtained in the review of interim financial information. It does not include detailed testing of source data or the operating effectiveness of processes and internal controls.

Key assurance procedures

Our key procedures included:

- Interviewing those responsible for management of the ENWL stakeholder engagement programme to understand activities in the reporting period, how the company is applying the AA1000APS (2008) principles and how issues identified are reviewed and managed.
- Review of documentation associated with the stakeholder engagement programme.
- Reviewing the responsibilities of the internal and external stakeholder panels including interviewing a sample of members of both panels.
- Reading and analysing internal and external information relating to ENWL's stakeholder engagement practices and the company's performance during the year

Our work was based on procedures performed at ENWL only. For the avoidance of doubts we have not tested the integrity of the underlying system/information.

Our conclusion

Based on the assurance work performed, in all material respects, nothing has come to our attention to cause us to believe that ENWL's description of its 2012/13 stakeholder engagement programme for the reporting year ended 31 May 2013 as found in sections 1.2.1, 1.2.2 and 1.2.3 of Sub-annex A1: Stakeholder engagement strategy (from entry to Ofgem's 2013 Stakeholder Engagement incentive scheme) of Annex 1: Stakeholder Methodology and Responses of ENWL's Well Justified Business Plan dated July 2013.

[1] Footnote 1: The levels of assurance engagement are defined in ISAE 3000. A reasonable level of assurance is similar to the audit of financial statements; a limited level of assurance is similar to the review of a half year financial report

This conclusion has been formed on the basis of, and is subject to the inherent limitations outlined above.

Responsibilities of Directors and independent assurance provider

ENWL's responsibilities: The Directors are responsible for the preparation of the Part 1 submission (Evidence to present minimum requirements of stakeholder engagement) under Ofgem's Electricity Stakeholder Engagement Incentive Scheme 2012/13 and for the information and statements contained within the sections. They are responsible for determining the stakeholder engagement goals and establishing and maintaining appropriate performance management and internal control systems from which the reported information is derived.

Deloitte's responsibilities: Our responsibility is to independently express conclusions on the subject matter specified by ENWL. This is set out above.

- We complied with Deloitte's independence policies, which address and, in certain areas, exceed the requirements of the International Federation of Accountants Code of Ethics for Professional Accountants. We have confirmed to ENWL that we have maintained our independence and objectivity throughout the year, and in particular that there were no events or prohibited services provided which could impair our independence and objectivity in the provision of this engagement.
- Our report is made solely to ENWL in accordance with our letter of engagement for the purpose of the Directors' governance and stewardship. Our work has been undertaken so that we might state to ENWL those matters we are required to state to them in this report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than ENWL for our work, for this report, or for the conclusions we have formed.
- This report provides no assurance on the maintenance and integrity of ENWL's website nor the controls used to maintain this website's integrity, and in particular whether any changes may have occurred to the information subsequent to our work. These matters are the responsibility of the Directors of ENWL.

Deloitte LLP

London, 21 June 2013

SUB-ANNEX A3: Engaged Consumer Panel summary, February 2013

Engaged consumers less willing to pay extra for reducing the duration of power cuts than unengaged consumers

There is little difference in the willingness to pay extra to reduce the duration of power cuts between ENW customers (£1.01 - small sample or £0.96 - large sample) and non-ENW customers (£0.94). However, ENW's Engaged Consumers (£0.86) are much less willing to pay extra to reduce the duration of power cuts. This is probably because, Engaged customers have been made aware of how reliable their existing electricity network is (99.99%) and are less willing to fund marginal gains than the wider population.

Engaged consumers less willing to pay extra for reducing the frequency of power cuts than unengaged consumers

There is little difference in the willingness to pay extra to reduce the frequency of power cuts between ENW customers (£0.79 - small sample or £0.66 - large sample) and non-ENW customers (£0.68). However, ENW's Engaged Consumers (£0.58) are less willing to pay extra to reduce the frequency of power cuts. Again, this is probably because, engaged customers have been made aware of how reliable their existing electricity network is (99.99%) and are less willing to fund marginal gains than the wider population.

Engaged consumers much more willing than unengaged consumers to pay extra for reducing major equipment failure.

There is little difference in the willingness to pay extra to reduce major equipment failure between ENW customers (£0.00 - small sample or £0.12 - large sample) and non-ENW customers (£0.05). However, ENW's Engaged Consumers (40p) are much more willing to reduce major equipment failure. Engaged customers appear more likely to recognise benefit in investing to reduce major power cuts - those lasting more than 18 hours - than investing to reduce the duration and frequency of normal outages.

ENW customers more willing to pay extra than non-ENW customers

Electricity consumers in ENW's region are more willing to pay for investment in the network than those outside of the region. On average, non-ENW customers say that they would be prepared to pay £4.02 per year to fund additional investment. ENW customers would be willing to fund £4.31 (large sample) or £4.59 (small sample) of additional investment in the network. Engaged ENW customers, who understand the electricity sector and the role of DNOs better than un-engaged customers, say that they would be willing to pay £5.14 extra to fund investment in the network.

Rural customers more willing to pay extra than urban customers

Outside the ENW region, rural customers (£4.22) are a little more willing to pay extra for network investment than urban customers (£3.96), a gap of 26p. The gap between rural (£5.27) and urban (£4.12) willingness to pay within ENW's region is about four times bigger, with ENW's rural customers willing to pay 115p more than its urban customers.

SUB-ANNEX A4: Engaged Consumer Panel summary, December 2012

Summary

Willingness to fund investment is falling

Continuing recessionary pressure and increasing electricity bills are dampening appetite to fund additional ENW investment. On average, willingness to fund additional investment has dropped by 22% (from £6.03 to £4.68) since last year. There is less appetite for investing to reduce the environmental impact of the network, but much more for improving the network's ability to withstand extreme events like floods and storms.

Restore power more quickly in the Winter

Almost all Engaged Electricity Consumers say that it is important for ENW to repair power cuts more quickly in the Winter than in the Summer. Three in five would accept an average summer restoration time of 5.5 hours in exchange for an average winter restoration time of 1.5 hours. ENW should consider re-structuring resources to meet heightened consumer concerns – and expectations – in the Winter.

Summary

Worst time to be without power is evening – especially in the Winter

The least inconvenient time to be without power is after 10pm followed by Lunch Time (12 noon to 2pm). Conducting planned outages in the Summer after 10pm or between 12 noon and 2pm would be the 'best' times for ENW to schedule essential maintenance on the network.

Fewer longer planned outages preferable to more short ones

More than half of Engaged Electricity Consumers say that the maximum number of planned outages should be two or less per year. While most express no preference for when scheduled work should occur, those that do prefer weekdays to weekends.

More than eight in ten say that extending a planned power cut to complete work on the same day is preferable to restoring power and scheduling another planned shutdown on another day. Over half would accept a 4 hour extension if work cannot be completed within the scheduled time.

Summary

65% say that £9 per year to fund interest payments is acceptable to ensure power flows

Though describing the cost of capital in terms of mortgages and personal finance helps, most don't understand the concept. Nonetheless, the majority say that they prefer the certainty of long term loans to any potential savings associated with short term loans.

Nine in ten say that they would prefer the current approach to funding capital costs based on repaying interest only at an additional cost of £3 per year to an approach incorporating capital repayment at an increased cost of £14 per year. Consumers don't understand who, how or when they would benefit from ENW repaying capital and some are suspicious about who would benefit most: consumers or shareholders.

Awareness and recognition of ENW's role is improving slowly

Awareness of the ENW brand has increased from 23% in 2010 to 29% in 2012.

Recognition of what you do has improved from 5% to 12% over the same period.

Key Findings

1 North West residents are willing to pay for further infrastructure improvements

Despite widespread concern about rising energy prices and the research process highlighting the impact on personal bills, participants are prepared – on average – to pay £2.27 more than the 'medium' level of your initial investment plan to allow Electricity North West to make further improvements to its service provision.

Across Electricity North West's 2.4 million connections and over a 5 year period, this equates to permission – and willingness to pay – for £27 million worth of additional investment.

"When you're paying over a thousand pounds in power bills, £2 is actually nothing, isn't it?"

"If you go to a substation to repair it, I'm sure it's better to repair it for the future … if something has gone wrong, you should put it right and put it right for the future as well."

"£2 over a year isn't a lot. Most people can afford it."

2 'Will it keep the lights on?'

In assessing investment decisions, participants tend to consider three issues in deciding whether they are – or are not – prepared to pay for additional investment. The most important of these is the extent to which participants believe any decision will contribute to maintaining, or ideally, improving the reliability of the network.

Consumers look first and foremost to ensure that they have a reliable connection to the electricity network and so prioritise decisions like replacing assets before they fail, stopping disruptive metal theft, and upsizing assets to allow for future growth.

"In our house, we rely on the electricity completely, so a power out is a problem."

"They've had these swoops on cables recently … we ought to try to look to protect any cables or substations or whatever where they are going to be vulnerable."

"If you're running a company and you're dependent on power and it goes out, your company is crippled and you can't make any money."

3 'Is it dangerous?'

The second of the three considerations is for the safety of the public and Electricity North West's staff. Participants show clear concern for safety, easily imagining the dangers posed by the electricity network, and so are prepared to fund an increased programme of asbestos removal, measures to address the use of oil in substations and cables, and others measures to minimise public safety incidents.

"I think a planned programme for getting rid of asbestos and the oil in substations ought to be built in."

"Asbestos ought to be prioritised so that the staff are protected from that because it's a known hazard that they're going to have to go into."

4 'Does it protect the vulnerable?'

The third consideration in assessing the value of an investment decision is the extent to which any measure is seen to protect or aid vulnerable groups. Priority service for vulnerable groups was the area participants were most willing to fund additional investment for, with other measures – like enhanced service to sole-energy customers – popular too.

"When a baby needs feeding and it needs to be a warm feed, they don't have any appreciation of why they're not getting it instantly … looking after a very young baby that's crying for its nosh is very difficult."

"My stepmother, who is 87, she got a phone call to say that we are doing some work and you'll be off from two until six or whatever. I thought 'that's very good'".

5 Scepticism about long-term investment

Participants demonstrate considerable scepticism about the ability of any organisation, including Electricity North West, to make very long-term investment decisions. They question on what basis the North West's electricity needs and demands in 2032 or 2052 can be predicted and call on Electricity North West to limit investment in preparation for electric vehicles, heat pumps, and new renewable energy sources.

"Investing for solar panels or wind power for me is a total waste of time because I wouldn't receive any payback."

"I think when we're currently in a recession, I think generally if you asked Joe Public to pay more for something that's 20 or 30 years off in principle, I think they're feeling the pinch now, so it's quite hard for them."

"I don't see what providing the electric stations or whatever for recharging cars should be borne by people who many not use a car or may not see the need for it."

6 The DE challenge

In total, one-in-five are unwilling to pay the ‘medium’ investment level. This rises, however, to almost half amongst socio-economic group DE; those working in semi or unskilled manual jobs or those entirely dependent on the state through unemployment, disability, or old age. This socio-economic group, characterised by low incomes, demonstrates a clear tendency to be less willing – or able – to pay the ‘medium’ investment level.

“I’ve got four kids and they’ve all got everything they want twice over … I get really disgruntled thinking there’s a giant amount of profit that my energy provider is making and they are sitting there going ‘brilliant’.”

7 Views are largely uniform

Aside from the divergent views of socio-economic group DE, there are few significant differences between men and women, older and younger participants, and rural and urban respondents. Younger participants, those aged 18-34, do however demonstrate a greater willingness to fund investment into environmental measures like connecting renewable power generators and reducing Electricity North West’s carbon footprint.

“You’ve asked about the environmental impact and the visual impact … for me, it would be important for them to focus on [the environmental] aspect because I think it’s really important at the moment. We’re supposed to be getting to the point of no return.”

8 Protecting the vulnerable is seen as good value-for-money

Participants were asked to consider their willingness to pay for each investment option as a theoretical decision without cost implications and, again, with a cost attached. In most cases, willingness to pay decreased once a cost was attached.

For a small number of decisions, however, willingness to pay *increased* once cost was considered and these included enhanced service to sole-energy customers and priority service for vulnerable people. Participants, assessing the relatively low cost of these measures against their positive impact for vulnerable people, deemed these investments to be socially worthwhile and to offer good value-for-money.

“I was surprised at how little cost for some of the things.”

“That’s a priority really … vulnerable people, old people, invalids, kids, pregnant women. I think that should definitely be the priority.”

“If you said to me do I want to pay £2 extra a year for green issues, or do I want to pay £2 a year towards the vulnerable, I would say go for the vulnerable. I’m not prepared, if I’ve got the choice, to go for the green.”

9 Awareness of Electricity North West has increased slightly

Since the first wave of research, recognition of the Electricity North West name has increased from 23% to 25% and understanding of Electricity North West’s role in the electricity industry has cliϒbed from 5% to 8%.

"I've seen the vans in my area, but didn't realise what they actually do."

"I'd heard of them because where we live we tend to have slightly more power cuts. I tend to ring them up fairly regularly."

"I was amazed when I did the survey because I honestly still thought that NORWEB had something to do with the power."

Summary

- 21% say they are unwilling to pay your 'medium' level of investment. Nearly half of these come from social grade D or E.
  - DEs are much more unwilling to pay your 'medium' level of investment than the population as a whole.
  - This group is at least three times more likely to prioritise the following investment decisions as 'low' than the panel as a whole.

Investment Decision	Times more likely to say 'low' than population as whole
Replacing assets before they fail	4.0
Opportunistic upsizing of assets to facilitate future connections	3.6
Reduce oil spills from cables	3.3
Protection against metal theft	3.3
Expectation of customer service team	3.2
Ensuring network has enough capacity to meet demand	3.0
Reduce oil spills from substations	3.0
Protection against storms	3.0
Minimising public safety incidents	3.0

- Before knowing impact on their bill, customers are prepared to pay on average £6.03 to fund additional ENW investment. After considering impact that investment decisions would have on their bill, willingness to fund drops to £2.27 above the cost of your 'medium' investment level.
- On average, the panel is willing to pay more than your 'medium' level of investment on all investment decision except:
  - Preparing for electric vehicles/heat pumps
  - Addressing equipment noise
  - Fixed price small scale connections
  - Protection against flooding
  - Connecting and managing renewable power generators
- The areas on which the panel is willing to pay 10% or more than your 'medium' level of investment are detailed below. ENW may wish to consider increasing the 'medium' level of investment on these areas:
  - Providing priority service for vulnerable
  - Socialisation of A&D charges
  - Replacing assets before they fail

- Protection against metal theft
- Removing asbestos
- Opportunistic upsizing of assets to facilitate future connections
- Reduce oil spills from substations
- Minimising public safety incidents
- Reducing ‘pinch points’
- Reduce oil spills from cables
- Providing enhanced service to sole-energy customers

Tracking Measures

Awareness of Electricity North West has increased slightly since December 2010 with 25% of adults in the North West aware the ENW brand.

The public’s understanding of what ENW does is also improving slightly from a very low base. Just over a year ago 5% of people in the North West could identify what ENW does. Now, 8% recognise the role you play in the electricity sector.

SUB-ANNEX A5: Engaged Consumer Panel, North West vs National summary, June 2012

Key findings

- **The issues on which consumers in the North West are more willing to pay for an enhanced service than the British population as a whole are:**
- Mobile generation for customers if power cannot be restored within three hours
- Reducing equipment failure that causes major power cuts
- More comprehensive safety campaigns
- More proactive call centre

SUB-ANNEX A6: Engaged Consumer Panel summary, July 2011

Engaged consumer panel 2011

Power cuts – fear of them, the need to minimise them, the inconvenience and disruption caused by them –were a dominant issue throughout the Engaged Consumer Panel and focus group research.

- **Many viewed Electricity North West's only task as 'keeping the lights on'.**
- **For most, their only expectation of Electricity North West is that the company will work hard to keep power on and most wanted to see Electricity North West improve on the existing 99.99% reliability.**
- **Reducing the number of power cuts and limiting their duration was seen as Electricity North West's most important short-term goal, most important objective for long-term investment and the most important value for the company to hold.**

"I expect the power to always be on, you need it for everything you do."

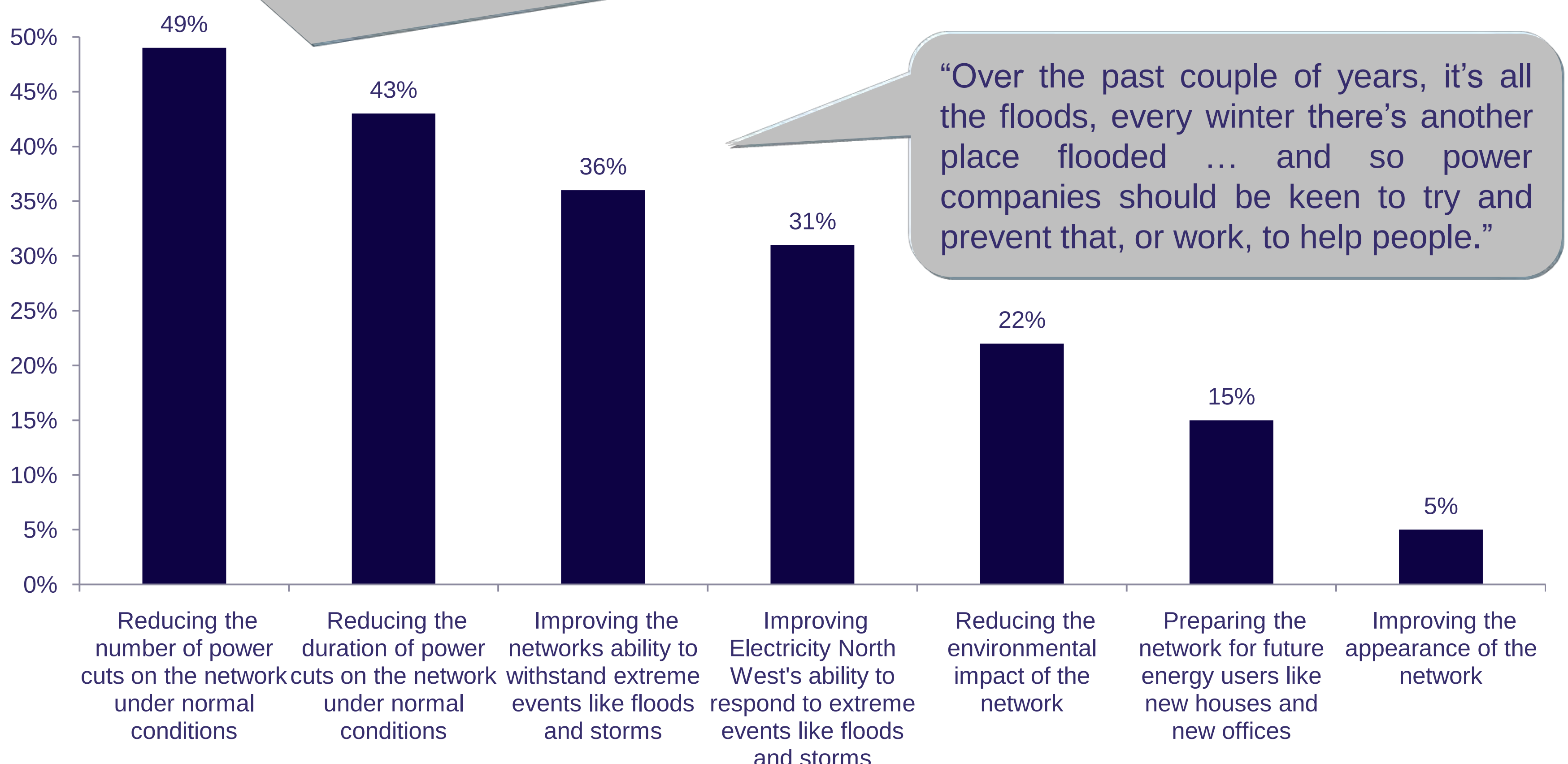
"When the guy next door cut the street's power off, it was in winter, so it was pitch black, so you get home and you've no lights. You don't know where your candles are ... you do get anxious quite soon."

"We had a power cut. I think it was earlier this year, it wasn't that long ago, it was off for about an hour, an hour and a half. When it first goes, it's gone in the morning, you've no idea how long it's going to be off for. Is it going to be off for five minutes or five hours? You get so used to the power being on, I went to the front room to put the telly on, to see if there was anything on the news about it, I was trying to put the telly on even though the power was out."

Reducing the number and duration of power cuts is seen as the most important investment priority for ENW, with reducing the impact of extreme events the next most important.

“Having a power cut, even though they don’t happen very often, that’s the thing that you think about, and that’s the thing that people really don’t want to happen. So that’s whyI think it is important.”

“Over the past couple of years, it’s all the floods, every winter there’s another place flooded … and so power companies should be keen to try and prevent that, or work, to help people.”



Q *Please rate the areas of investment ... [Figures in bars % saying most or 2nd most important area of investment]*

Populus

Base: 221

Nearly half are not prepared to pay anything extra to fund additional investment by Electricity North West.

Average amount prepared to pay to fund additional investment: **£4.70**

Q *How much extra, if anything, would you be prepared to pay in your electricity bills per year to fund additional investment?*

Populus

Base: 221

Key issues to consider

- **Fear of power cuts dominates thinking about ENW**
- **Expectations of ENW are simple but unrealistic (perfect reliability of supply) – important to explain why cuts happen and how quickly ENW gets the power flowing**
- **Reaction is strongly negative to any suggestion that ENW might limit / control when and how appliances can be used**
- **Despite being ‘Engaged Consumers’ many admit it is difficult to make judgements on benchmarking / investment – better understanding of the costs and benefits is essential**

SUB-ANNEX A7: Regional stakeholder workshops summary and slides, December 2012

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Electricity North West ran a series of stakeholder workshops in different parts of its service area during Autumn 2012, to have informed discussions with key stakeholders about its proposed investment plans under the next Ofgem price control period.

The workshops were organised as independently-facilitated focus groups, with each event tackling specific themes and bringing together between five and ten key stakeholders with three or four representatives from Electricity North West. The stakeholders represented generators, major industrial and commercial customers, developers and development consultants, local authorities, environmental organisations and business groups. Each event was hosted by the Electricity North West regional operations manager for the geographic area, supported by colleagues with particular knowledge of the themes under discussion.

A total of 34 key stakeholders took part in the workshops, and a further two key stakeholders who were unable to attend submitted written comments. As expected from a diverse group of stakeholders, many different opinions were aired and there were some conflicting views about investment priorities. Some stakeholders were keen to see more investment in certain areas, even if it would mean increases in customers' bills, while others saw opportunities for savings that would help to reduce bills.

However, a number of key themes emerged on which there was broad agreement, if not full consensus, as follows:

Communication

Across the workshops, the key stakeholders asked for more and better communication from Electricity North West, particularly around power outages.

Suggestions included greater use of Twitter and social media, and inviting customers to register their email and mobile phone contact details via a website so they could receive automated message updates during outages. Business stakeholders wanted more detailed and accurate information about both planned and unplanned outages so they could mitigate against business risks, and several asked if Electricity North West would consult some business representatives about how they would like to see communication and account management improved.

Reliability and availability of the network

A consistent theme was that as a general principle, investment should lead to increased reliability and availability of the network.

This came up under a number of different discussions; for example, when discussing the issue of compensation for customers who experience power cuts, many of the stakeholders said they would rather the money was spent on preventing power cuts in the first place than compensating those who suffered them. When asked if Electricity North West should do more for customers who had no oil or gas, the feeling was that investment in improving reliability of the network would benefit them in particular, as well as the wider community. On the subject of undergrounding overhead power lines in rural areas, many felt that the investment was only justified if it led to improved network reliability as well as environmental benefit. And on the subject of tackling metal theft, many felt that increased investment in security was justified if it led to increased network reliability as well as improved safety.

Vulnerable customers

The stakeholders generally felt that current provision for vulnerable customers was about right, but there should be improved communication and information about how vulnerable customers are defined, what Electricity North West will do for them, and how they should go about getting help when they need it.

Among suggestions that gained support was that utilities, local authorities and emergency services could work together to create local emergency response groups, which would take over the support of vulnerable customers in times of crisis so that people received a consistent multi-agency approach.

Stakeholder workshop process

The vast majority of the stakeholders who attended the workshops felt they were very useful, welcomed the opportunity to give their views, and praised Electricity North West for taking the initiative to engage in full and frank discussion in this format. Many said they hoped the workshops would be just a first step in the company listening more to its key stakeholders as they felt that by working together they could help Electricity North West prioritise its investment to benefit as many people as possible.

Date	Venue Contact Details	ENWL Team	Delegates
20th November **Keswick**	Skiddaw Hotel, Main Street, Keswick, Cumbria CA12 5BN **017687 72071**	Martin Deehan Michael Proctor Alex Moore	Morgan Donnelly, Wind Prospect – Project Manager/Engineer Dave Shaw, Tata Steel – E&I Project Engineer Hennie van der Westhuizen, Iggesund – Central Engineering Manager Alan Brown, Iggesund – Strategic Planner John Stables, British Gypsum – Denice Gallen, Copeland Borough Council – Nuclear and Energy Officer
21st November **Bolton**	Britannia Hotel, Beaumont Road, Bolton, BL3 4TA **01204 855582**	Lee Maxwell Vincent Cranny Alex Moore Sarah Walls	Cllr Michael Green, Lancashire County Council – Cabinet Member for Transport… Dorothy Kelk, Friends of the Earth - Volunteer Marion Seed, Friends of the Earth - Volunteer Cllr Peter Goldsworthy, Chorley Borough Council - Leader Richard Jennison, CPRE – Environment Director
26th November **Manchester**	King's House Conference Centre, King's Church, Sidney Street, Manchester, M1 7HB **0161 276 8194**	Mark Williamson Michael Proctor Tony McEntee Jonathon Booth	Jackie Copely, CPRE Andy Beaumont, Lyondell Basell – Senior Electrical Manager Mike Reed, Trafford Council – Growth and Masterplan Manager Li-Hsia Chan, MIDAS – BDM Energy and Environment Russ Comrie, Cargill – Energy and Utilities Manager
27th November **Stockport**	The Stockport Guildhall, 169 Wellington Road South, Stockport, Cheshire, SK1 3UA **0161 480 6531**	Mark Williamson Vincent Cranny Brian Hoy Steph Rourke	Combined with Manchester event
28th November **Preston**	Preston Masonic Hall, Ashlar House, Saul Street, Preston, PR1 2QU **01772 252170**	Lee Maxwell Michael Proctor Tony McEntee Brian Hoy	Karen Smith, Matalan – Utilities Manager Dave Derbyshire, Matalan – Environmental Manager Shaun Costain, BAE Systems – Investment and Infrastructure David Halliwell, Green Energy from Nature - Rob Green, Blackpool Bay Area Co – Head of Enterprise and Investment John Knox, Energy Coast West Cumbria Ltd, Industrial Liaison Consultant Bev Taylor, Bruntwood – Energy Manager Wayne Calland, Bruntwood
30th November **Kendal**	Kendal College, Milnthorpe Road, Kendal, LA9 5AY **01539 814700**	Martin Deehan Alex Moore Jonathon Booth	Jack Ellerby, Friends of the Lake District Cllr Mike Tonkin, Eden District Council - Environment Chris Hardman, Carlisle City Council – Planning Manager David Haughian, Cumbria County Council – Strategic Programme Co-ordinator Andrew Davison, English Heritage – Principle Inspector of Ancient Monuments NW Richard Kemp, Tenet Consultants - BDM Richard Willacy, Telford Hart Associates Barry Watkinson, Morgan Sindall – Nuclear Development Director John Farmer, Cumbria Wildlife Trust

Stakeholder engagement

- We're engaging with stakeholders across the North West, from domestic customers to local government and large businesses
- We're also engaging with national stakeholders, like suppliers and the Department for Energy and Climate Change, to make sure that our plans reflect the views of all stakeholders

Roadshows

- We've held surveys, roadshows and school visits, helping us to shape our plans

Website

- We're encouraging people to have their say through our engagement website and leaflets

www.enwl.co.uk/switchedon

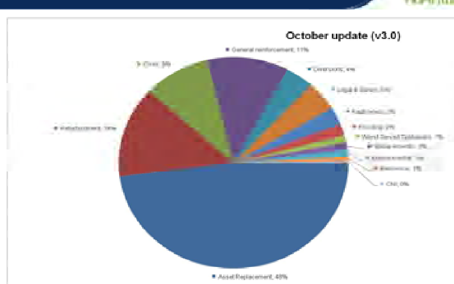
National feedback so far

Regional feedback so far

What we're already delivering

- We expect to invest around £2bn between 2015–2023 (in addition to £1.4bn between 2010–2015)
- This investment will focus on:
  - Improving *reliability* for customers by replacing ageing assets and increasing resilience against flooding or extreme events
  - Making the network *sustainable* for customers in the long term by extending capacity for a low carbon future where people use more electricity, and improving environmental performance
  - Keeping our part of the bill *affordable* for customers by innovating to keep costs at current levels

Proposed Network Investment



Today

- Based on the feedback we've already had from stakeholders, we have some proposals for the future of the network
- Do you agree with our proposals? What's most important to you considering Reliability, Affordability, Sustainability?
- We want to know what you think about our specific proposals, and also get your input on any other issues you want to raise

Today

- We're here to listen to your views
- We'll report your views back into the business so that we can finalise our plans
- We don't intend to answer everything today, but we'll keep in touch and report back to you with our final business plans

- Sue Hayman - Facilitator

Environment

- Q1

Many people feel that overhead power lines and pylons spoil the natural environment in our National Parks and Areas of Outstanding Natural Beauty. We are already investing in putting power lines underground in sensitive areas – but should we do more?

Environment

- Q2

Some of our larger and older underground cables use oil as an insulator. As they wear out or are damaged, leaks can occur which may harm the environment. We plan to replace 20% of oil-filled cables by 2023, but we could spend more, or save money by reacting only when there is a problem.

Environment

- Q3

The transformers in our substations are also filled with cooling oil. They can leak when things go wrong. Large substations have measures to catch oil leaks, but we could save money by working to minimum safety standards, or spend more by including small substations.

Social Obligations

- Q1

Some of our customers are described as 'vulnerable' because they may be elderly, or have new babies, or have particular needs. What extra services should we provide them free of charge?

Social Obligations

- Q2

What about customers who don't have gas or oil and only have electricity for their heating? Should we provide them with anything extra?

Social Obligations

- Q3

Noise. Much of our equipment is silent, but sometimes noise can be created. Where it does occur, how should we deal with it?

Safety

Q1

Metal theft from substations is a huge problem and extremely dangerous for the criminals, for our staff and sometimes for the public. It can also cause power cuts. Should we spend more money to secure our equipment?

Safety

Q2

We are committed to ensuring the safety of everyone who comes into contact with our network. How should we promote safety awareness?

Safety

Q3

Asbestos. Some of our older substations contain asbestos. What should our policy be on removing asbestos from these buildings?

Questions?

Reliability & Availability

Q1

Many of our pylons, overhead lines, underground cables, substations and equipment are ageing and will need replacing eventually. When this happens, should we replace them with the same or improved equipment?

Reliability & Availability

Q2

On average in the North West, a customer goes two years between power cuts and is without electricity for less than two hours in every two years. However, some customers, often in very rural areas, can have more than 15 power cuts in three years. What should we do?

Reliability & Availability

Q3

We could also do more to reduce the risk of major equipment failure; this is already low, but when faults do happen they can cause a major power cut of 18 hours or more.

Conditions for connection to the network

Q1

As homes and business use more electricity, the capacity of the network is used up. When its size needs increasing to help meet demand, who should pay?

Conditions for connection to the network

Q2

If a small business, like a farm or food producer, wants to expand or modernise and needs more electricity than their connection can handle, should they pay all the cost of upgrading the network, or a flat fee towards it? Or should the cost be shared amongst us all?

Conditions for connection to the network

Q3

What about when we need to increase the network to get new generators connected, like wind farms? Should the generator pay for any improvements needed, or just those that only they will use, or should we all share the burden?

Customer Satisfaction

Q1

If domestic customers lose power for more than 18 hours, we automatically pay them compensation. This is coming down to 12 hours, but should it be even less? Or should we only pay compensation if people claim it?

Customer Satisfaction

Q2

Under the existing regulations, industrial customers are only entitled to very low levels of compensation if they are without power. Is this fair?

Customer Satisfaction

Q3

To maintain an efficient network, there are times when we need to turn the power off on a planned basis. When this happens, how much notice should we give people? Is 2 days enough? Or 7 days? Or more than 7 days, with detailed timings of when power will be on and off?

Questions?

SUB-ANNEX A8: Parish council survey summary, December 2012

Key Findings from thŜ Parish Council Survey

Analysis of the survey results shows that for 15 of the 20 questions, the most commonly-selected answer was the Medium option. As a general rule, this meant the council felt that current or proposed levels of investment in this area were about right and should continue.

Low priority areas
For four of the questions (1, 3, 8 and 14) the Low response was the most commonly-selected answer. Selecting the Low answer meant the council saw this area as a low priority and would be happy for investment in this area to be reduced, potentially leading to a reduction in electricity bills.

Questions 1 and 3 were around who should pay for new infrastructure required when new connections are made to the network, either to put electricity in or to take it out. The councils felt that generally the developers should pay, and the public should not have to contribute through the socialising of costs across all consumers. Question 8 referred to compensation for businesses who experience power cuts; again, the councils felt that the cost of compensation for businesses should not be spread across all consumers.

Question 14 asked how long, on average, it would be acceptable for a consumer to be without power. The majority of councils selected the Low option (50 minutes), rather than supporting proposed investment to bring the average power cut duration down to 40 or 25 minutes.

High priority areas
Only one of the 20 questions drew the High option as the most popular answer. This was Question 6, which focused on the frequency of power cuts. It said that on average, a customer in the North West goes two years between power cuts, but in some very rural areas consumers can have more than 15 power cuts in three years. The majority of councils supported increasing investment so that no customer suffers this number of power cuts, even if this means increasing electricity bills.

This answer tends to reflect the fact that most parish councils are in rural areas. It is likely that if the same question was asked of consumers in urban areas, who are less familiar with power cuts, fewer would select the High option.

However, it is clear that for those who live and work in rural areas, reducing the frequency of power cuts in those areas is a higher priority than most other areas for investment.

Undergrounding of overhead lines
Question 11 asked councils whether they felt more should be spent on undergrounding existing overhead power lines. This is often an emotive subject, particularly when new high-voltage power lines are being proposed.

However, two-thirds of councils who responded picked the Medium option, feeling that the current policy of spending £1m per year on undergrounding overhead lines in sensitive locations identified by key stakeholders was the correct approach. Only 28% favoured doubling spending in this area, while a very small minority of 6% favoured stopping spending on undergrounding to reduce bills.

SUB-ANNEX A9: Stakeholder report summary, July 2011

Executive Summary

Journalists

- Journalists view Electricity North West almost exclusively through their relationship with the press office. Electricity North West's press office, although recognised as only recently established, is viewed positively and seen as responsive and helpful. Jonathan Morgan is spontaneously named by some journalists and is well-regarded.
- In terms of improvements, journalists want faster responses to queries, better access to management or company experts, and pro-active stories with local angle. Electricity North West's press office is inevitably compared to the larger, better established United Utilities operation. Though viewed positively, some believe that Electricity North West's press office has some way to go to match the level of service delivered by United Utilities.
- Knowledge of, and interest in, the electricity industry is very limited amongst non-specialist journalists. Local/regional journalists feel that they need to know only enough to write individual stories about Electricity North West and have no need for a more detailed or broader understanding.

Energy Suppliers and IDNOs

- This category, largely consisting of energy suppliers, approaches Electricity North West from a business perspective rather than a stakeholder perspective.
- They have regular contact with Electricity North West, and other DNOs, regarding invoicing and other supply issues. They look for Electricity North West to respond quickly to their queries, to express sympathy when mistakes are made, and to be 'can do' in putting things right. While Electricity North West is not regarded as particularly poor in this regard, these stakeholders are critical of all DNOs, seeing them as too often unresponsive and accusing DNOs of failing to grasp the need to provide good customer service. Some are critical of Electricity North West's inflexible billing systems and the perception that, at times, you are unwilling to explain how mistakes in billing came about.
- While Energy Suppliers and IDNOs have a good understanding of the energy industry and Electricity North West, not all have an actual interest in the industry. Many have little, if any, desire to know about aspects of Electricity North West's business outside their immediate sphere of interest.

MPs

- MPs, beyond recall of an association with United Utilities, know little about Electricity North West. Most MPs are uncertain as to the role played by Electricity North West, struggle to recall contact and have no basis on which to comment on Electricity North West's performance.

- MPs both call for greater contact with Electricity North West – welcoming the prospect of a short introductory meeting or briefing – while admitting that they are extremely busy and difficult to contact. MPs suggest carefully targeting communications to their interests or constituency needs.
- While MPs currently assume that Electricity North West is performing well – assuming that if it was underperforming they would have had complaints from constituents or others – their lack of knowledge poses a long-term danger. MPs, like consumers, have unrealistically high expectations of Electricity North West (perfect reliability at a minimum cost) and little sense of the difficulties of maintaining and renewing the North West's electricity infrastructure.

Regional Stakeholders

- Electricity North West's regional stakeholders – the largest business users, local government officials and elected members, local and regional forums – are extremely positive about Electricity North West. They praise both their contact with Electricity North West, Electricity North West's operational performance, and its commitment to long-term planning.
- So positively do regional stakeholders regard Electricity North West, that they criticise it for not doing more to promote itself. They call on Electricity North West to make it clearer – to the general public and opinion formers – the role Electricity North West plays in investing in the North West, in employing thousands and maintaining vital infrastructure. Regional stakeholders, alongside MPs, are the keenest supporters of local and regionally focused CSR actions.

NGOs

- NGOs are often extremely narrowly focused, with a detailed knowledge and interest in a particular area but with little awareness beyond this specialist area. NGOs are sharply divided in terms of their contact and perceptions of Electricity North West.
- Those engaged by Electricity North West are extremely positive. They see Electricity North West as sharing their passion, typically for environmental issues, and praise the company's performance and staff. Contact with Electricity North West has given these stakeholders some understanding of the issues faced by Electricity North West and its role in the wider sector.
- Those NGOs without contact, however, know much less about Electricity North West. These NGOs are not critical of Electricity North West, but instead simply know too little about it to express any type of informed opinion of the company.

Regulators

- Regulators, amongst all stakeholders, tend to have the greatest knowledge of Electricity North West and have regular contact with it.

- Electricity North West is viewed positively and across a range of areas – quality of contact, operational performance, forward planning – is seen to compare favourably to the bulk of other DNOs.
- Much of regulators' contact with Electricity North West is required by law and part of the regulatory regime governing the industry. Regulators are keen to stress that this is a minimum level of contact and that Electricity North West and DNOs are free to do more. Regulators stress the importance of this in relation to Electricity North West (and other DNOs) doing more to engage with non-regulator stakeholders and to maintain both informal, and formal, relations with regulators.

SUB-ANNEX A10: Engaged consumer panel, full report, January 2014

Engaged Electricity Consumer Panel
Electricity North West

January 2014

Populus
RESEARCH | STRATEGY

electricity north west

Summary

Strong support for ENW's plan to be amongst the top 3 DNOs on connections

Consumers find it difficult to estimate the time required for new connections, but, on average, expect a quote for a new connection within 7 days. ENW's current proposal is ahead of this expectation level. However, the expected time to actually install the new connection is on average 13 days, well below the current number of days in ENW's proposal. More than four-fifths of respondents favour ENW's plan to be in the top three performers.

Upgrading medical networks and providing additional support during outages are most important ways to support vulnerable customers

Engaged Electricity Consumers – and over 55s in particular, believe it is important for ENW to protect the vulnerable, most notably by upgrading hospital infrastructure and providing temporary power during outages. While almost all respondents consider those with medical needs and the elderly as vulnerable, it is notable that more than half (especially women) say that families with newborns should also be classified as vulnerable.

Summary

Appetite for ENW to take action against electricity theft even if costs outweigh the financial benefits increases with age

A desire for fairness evokes strong emotions in the call for action against electricity theft. At least four in five Engaged Electricity Consumers say that it is important for ENW to do all of the activities under consideration – especially assessing/identifying premises where electricity theft is likely. While 74% of over 55s want ENW to take action even if the costs outweigh the financial benefits, less than half of 18-34s (43%) agree.

Efficient and easy customer service is vital when customers are without power

Respondents consider a number of customer service areas to be extremely important, most notably having their calls answered quickly, explaining why the power is out and when it will be restored. Text and the ENW website are the most likely alternative methods of contacting ENW when phone lines are down. A small proportion would use social media including Facebook and Twitter.

Summary

Under normal circumstances, there is little appetite for increasing current compensation levels if it means an increase in electricity bills

70% of Engaged Electricity Consumers do not think that compensation levels should be more than £54 after 18 hours without power. Some resist the 'blanket compensation culture' and suggest that compensation should be based on culpability relating to poor maintenance rather than uncontrollable events – including extreme weather. However, nearly half (46%) think that compensation relating to extreme weather should be paid after 18 rather than 48 hours. Nearly half favour compensation of at least £50 per day, while a third favour retaining the existing level of payment.

Respondents believe that compensation should be paid to all affected by the outage, and that the level of compensation should be the same irrespective of the number of customers affected, however those aged 18-30 are somewhat less convinced by both these arguments. Only a third (32%) believe business customers should be recompensed for total loss of earnings.

Summary

Willingness to fund investment is growing

On average, willingness to fund additional investment has increased by 28% (from £4.68 to £5.97) since 2012. Males and over 55s are most willing to pay extra.

As in previous years, investment related to 'keeping the lights on' tends to be most prised by Engaged Electricity Consumers. 'Improving support for vulnerable customers' (measured for the first time this year) is also clearly important to consumers. Other areas measured for the first time (reducing electricity theft and new connections) are relatively unimportant.

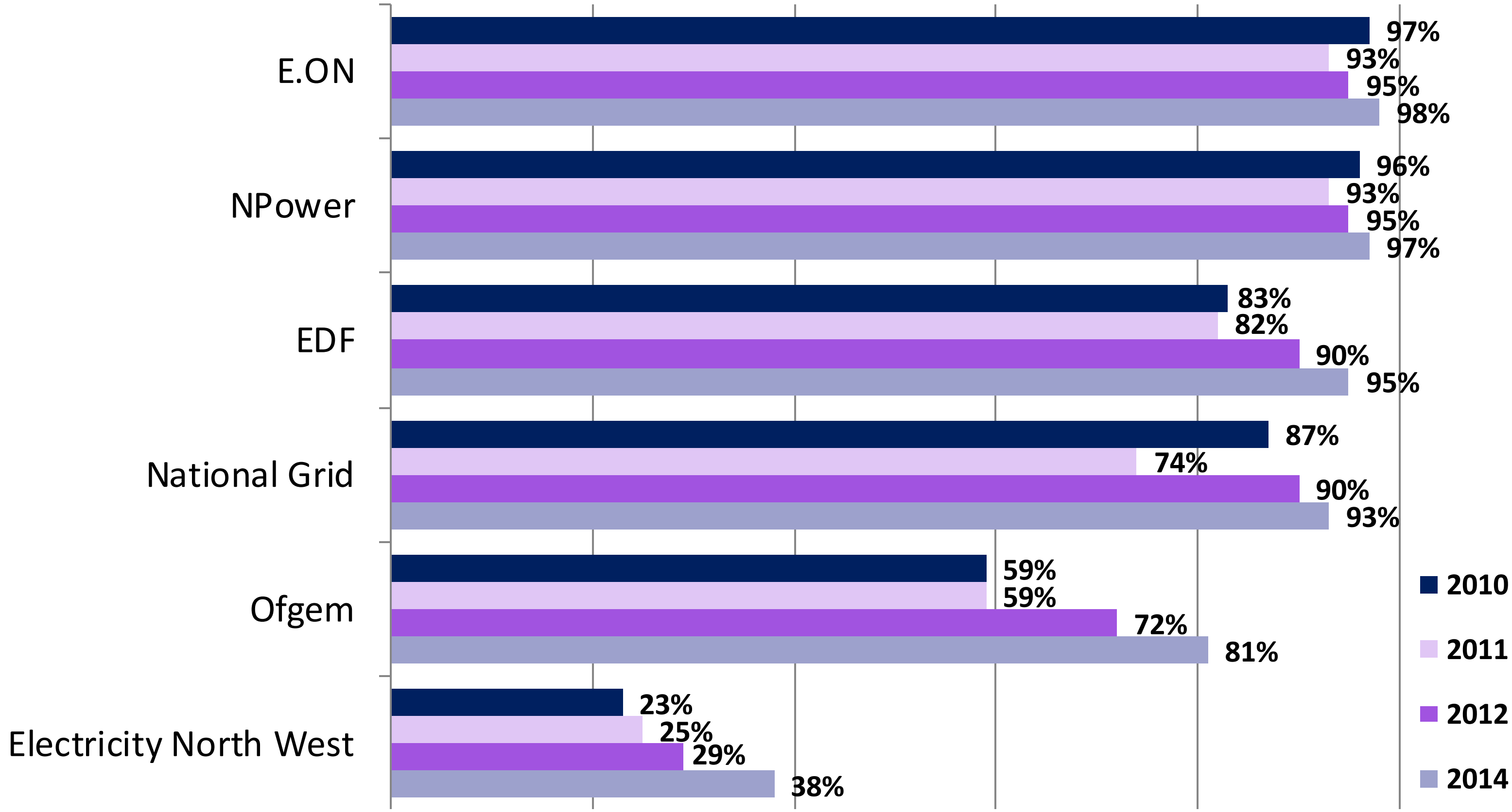
Awareness and knowledge of Electricity North West continues to grow

Awareness of the ENW brand has increased from 23% in 2010 to 38% in 2014. Understanding of the role of ENW has also grown to 21% in 2014, from 5% in 2010. Both awareness and recognition of ENW's role is higher among men and over 55's than other demographic groups.

Awareness and understanding of ENW

Awareness of ENW continues to grow…

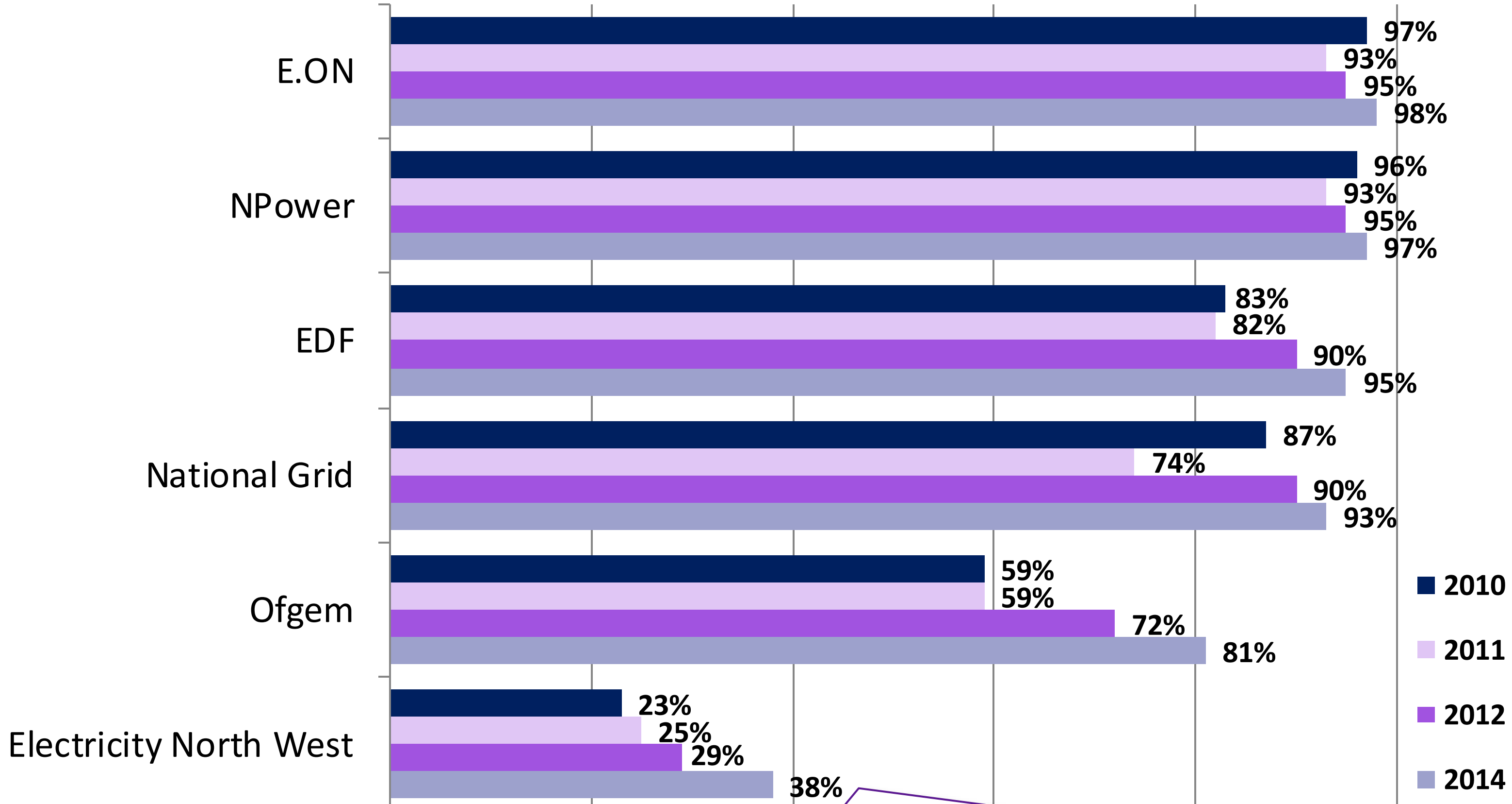
Before today, which of the following companies and organisations had you heard of?



[Base 2014: 914]

Awareness of ENW continues to grow…

Before today, which of the following companies and organisations had you heard of?

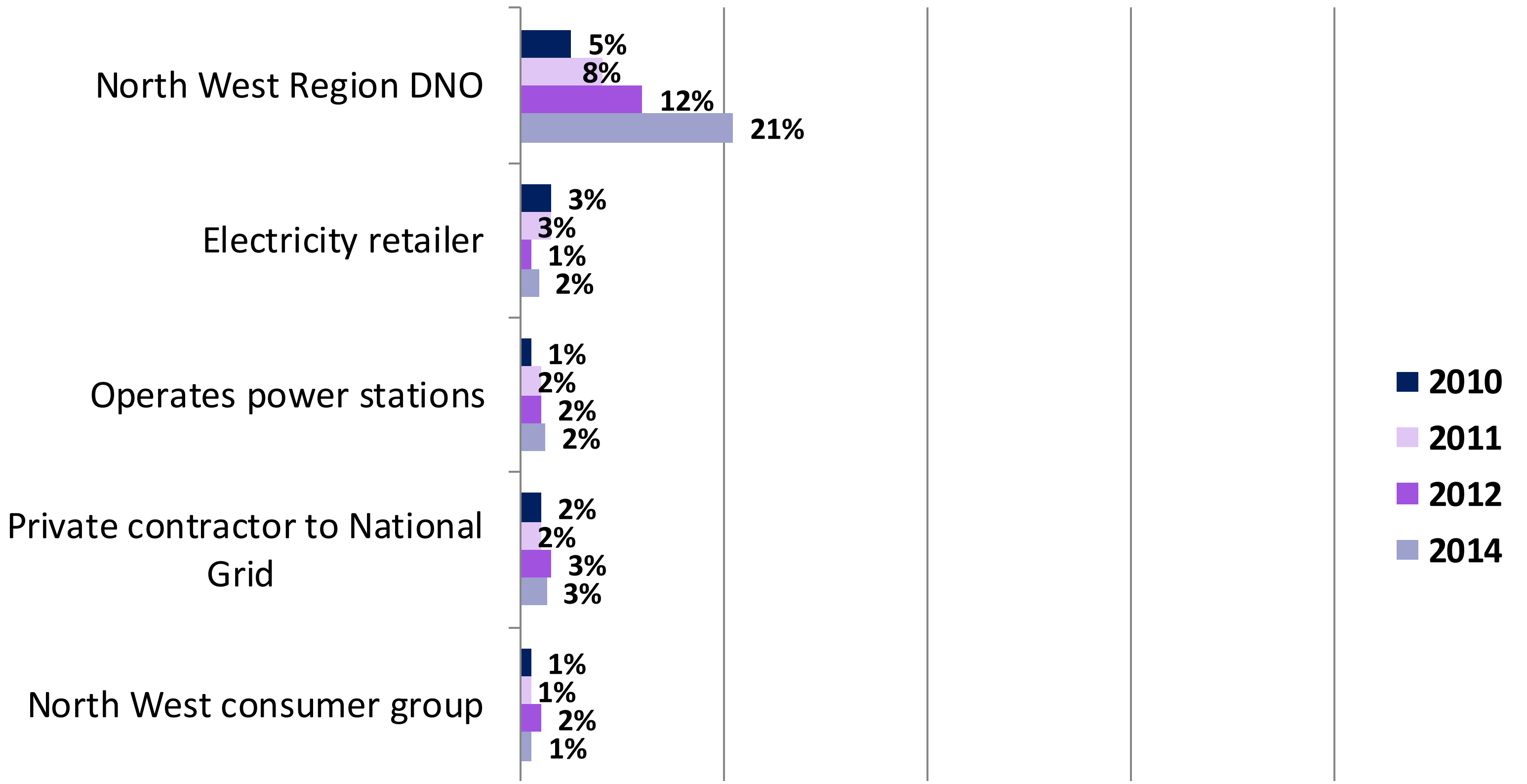


"I had never heard of them before the survey then the very next day a van past me whilst I was walking the dog with an emergency ring."

[Base 2014: 914]

… as does understanding of what ENW does

To the best of your knowledge … Describe what Electricity North West does



[Base 2014: 914]

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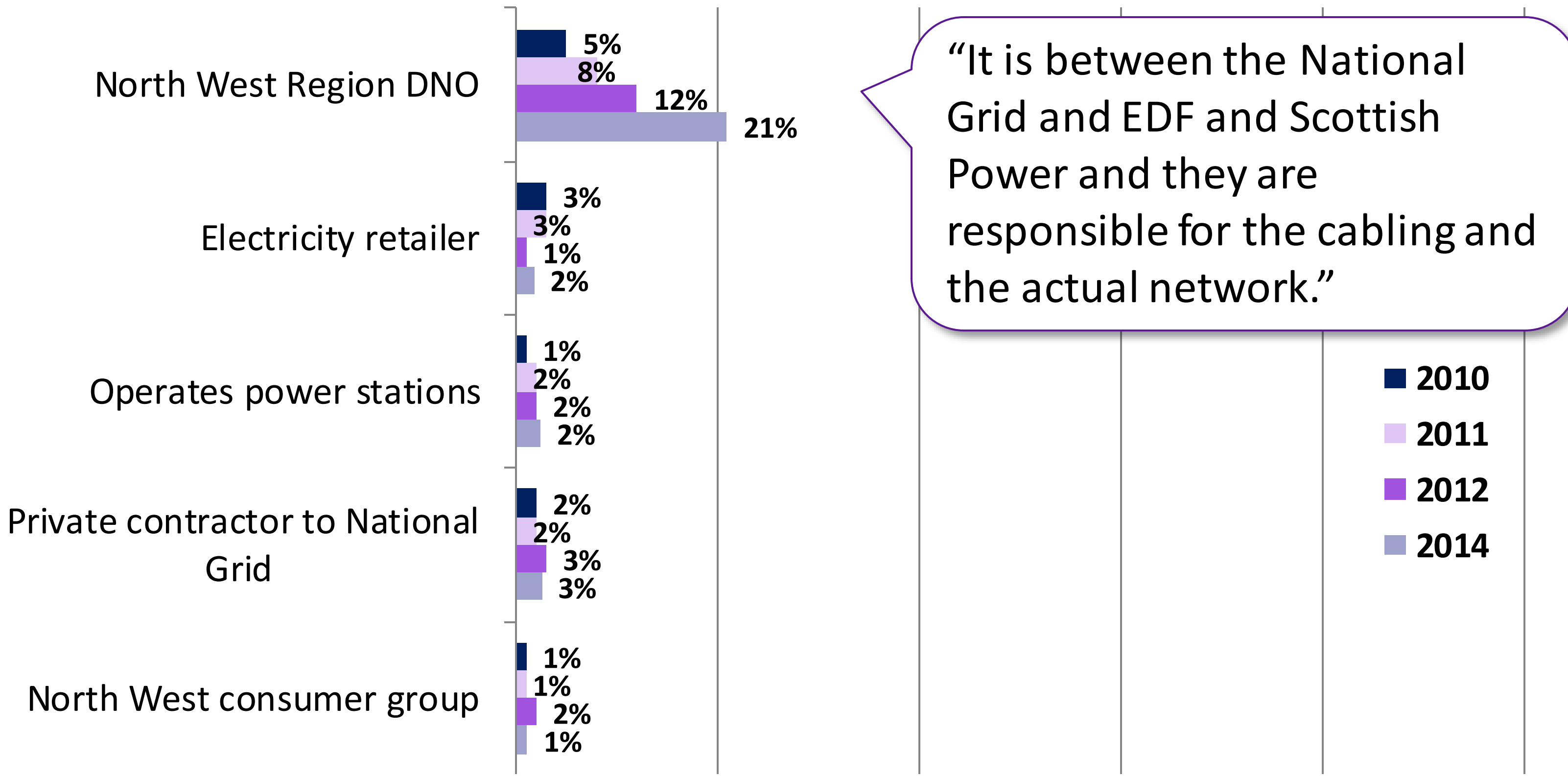
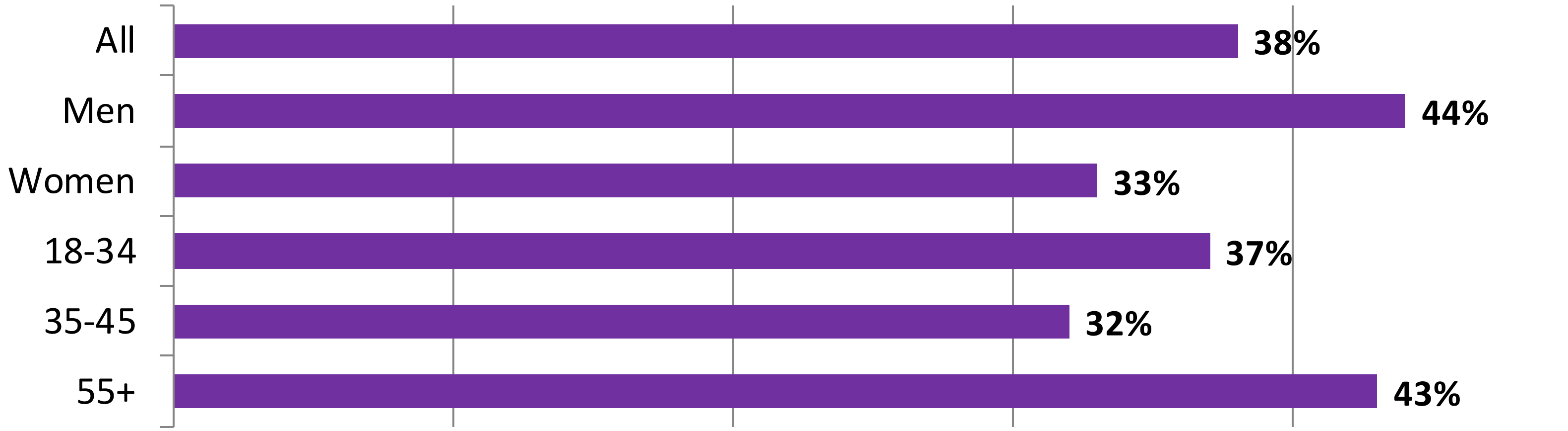


[Base 2014: 914]

Men and over 55's tend to know more about ENW than other groups

Before today, had you heard of Electricity North West?



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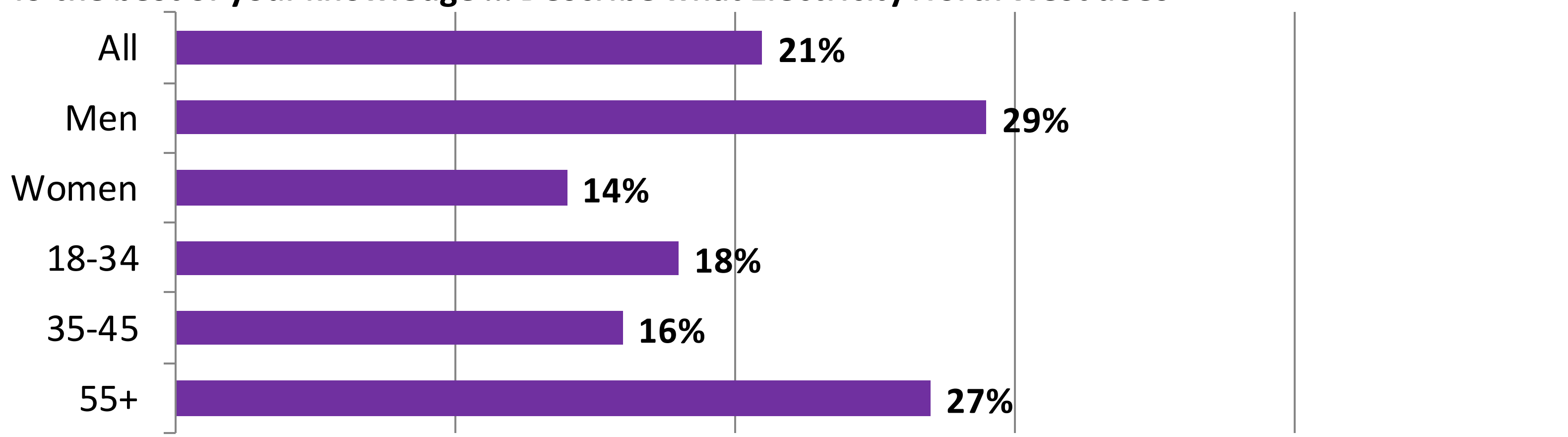
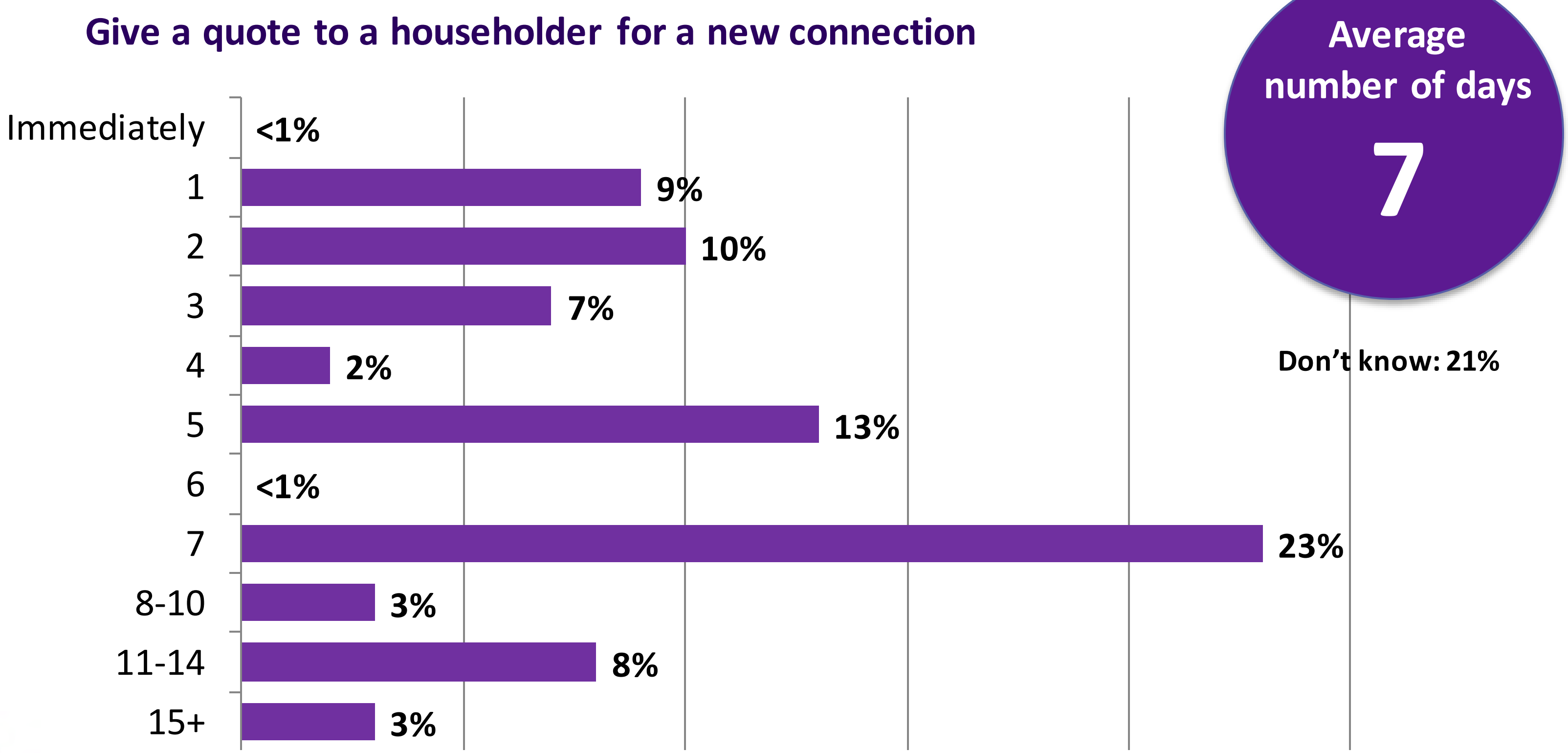


[Base 2014: 914]

Connection Targets

ENW's current proposal beats the average expectation of 7 days to quote

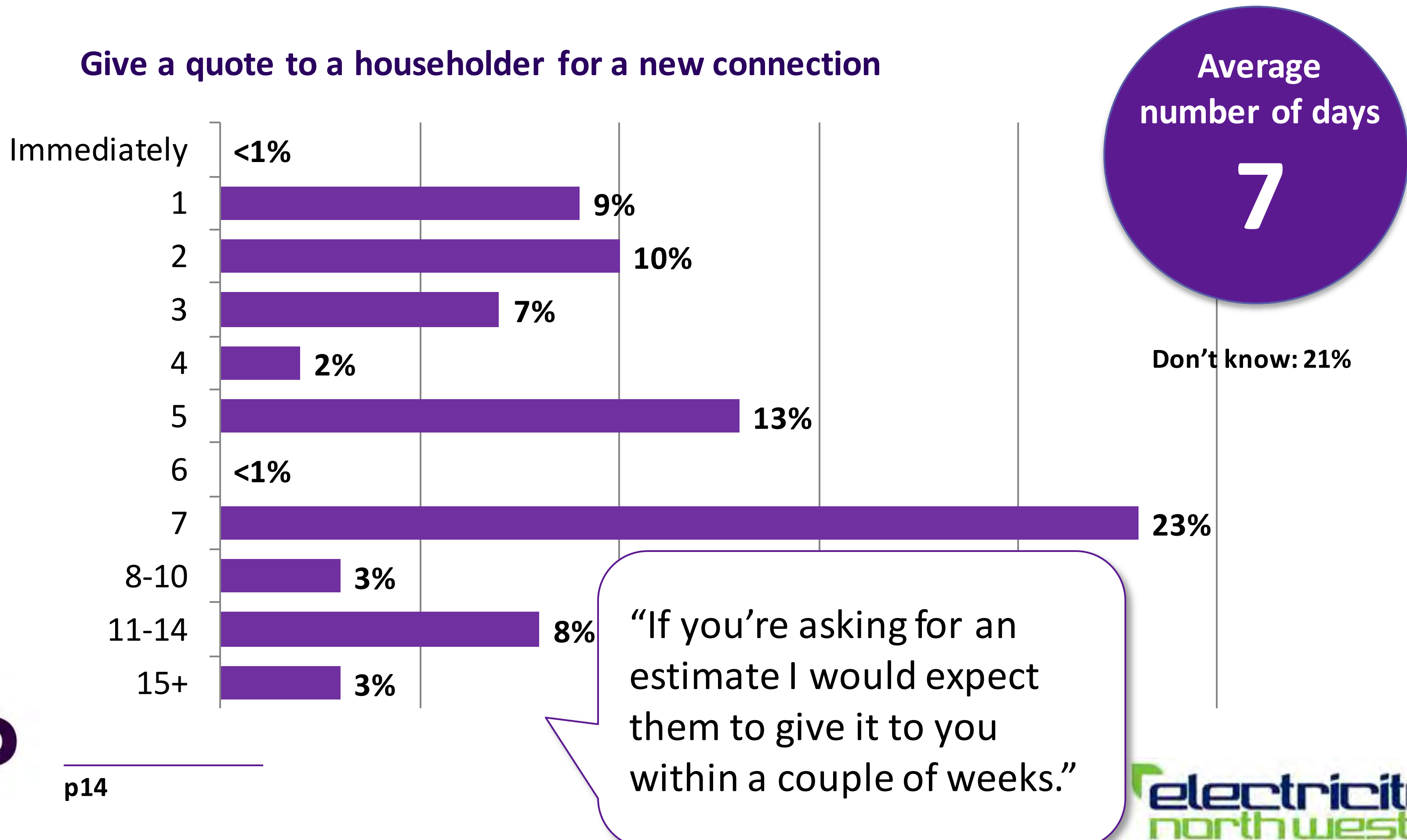
In days, how long do you feel it is reasonable for Electricity North West to need in order to...



[Base 2014: 824]

ENW's current proposal beats the average expectation of 7 days to quote

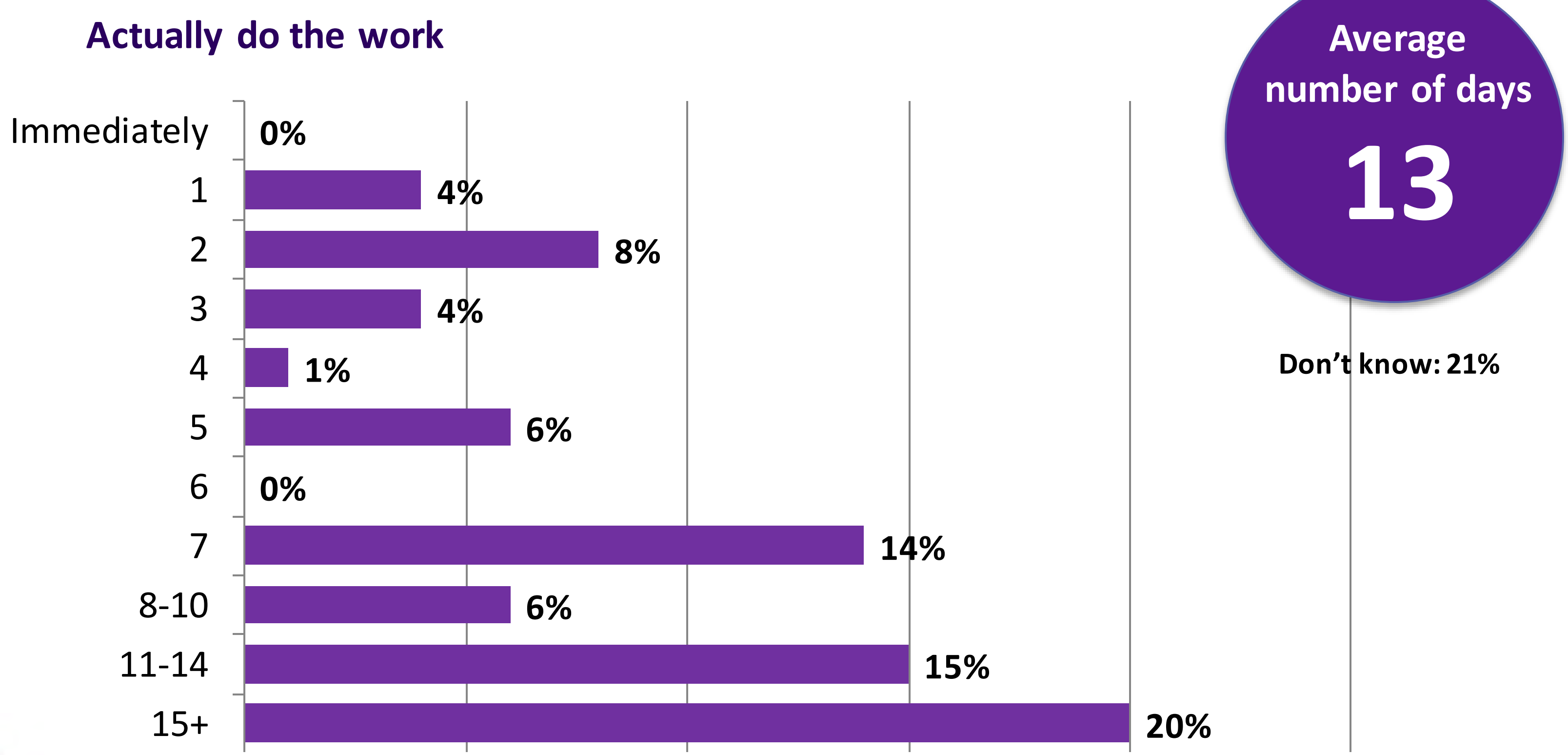
In days, how long do you feel it is reasonable for Electricity North West to need in order to...



[Base 2014: 824]

13 days is well below the current number of days included in ENW's plan

In days, how long do you feel it is reasonable for Electricity North West to need in order to...

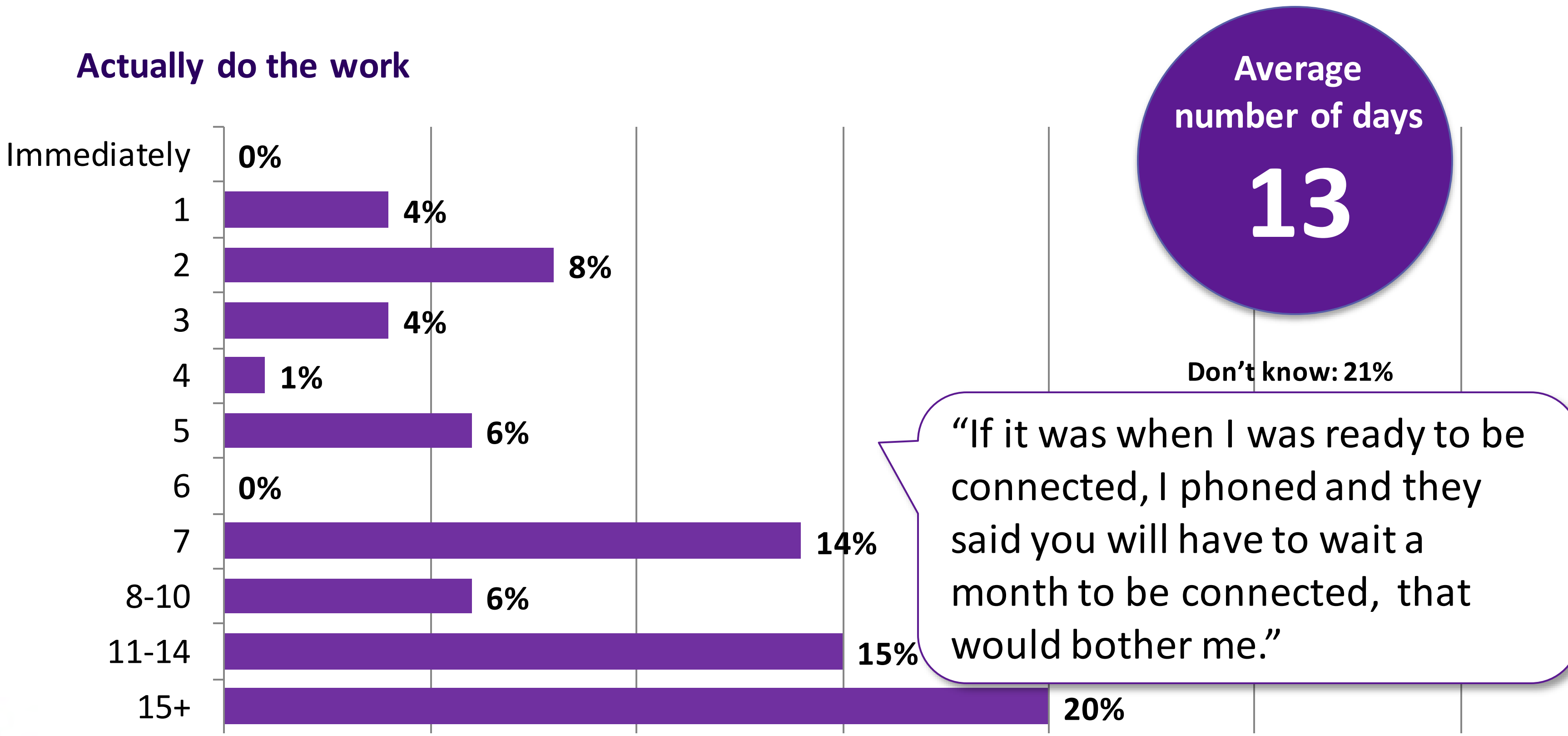


[Base 2014: 824]

13 days is well below the current number of days included in ENW's plan

In days, how long do you feel it is reasonable for Electricity North West to need in order to...

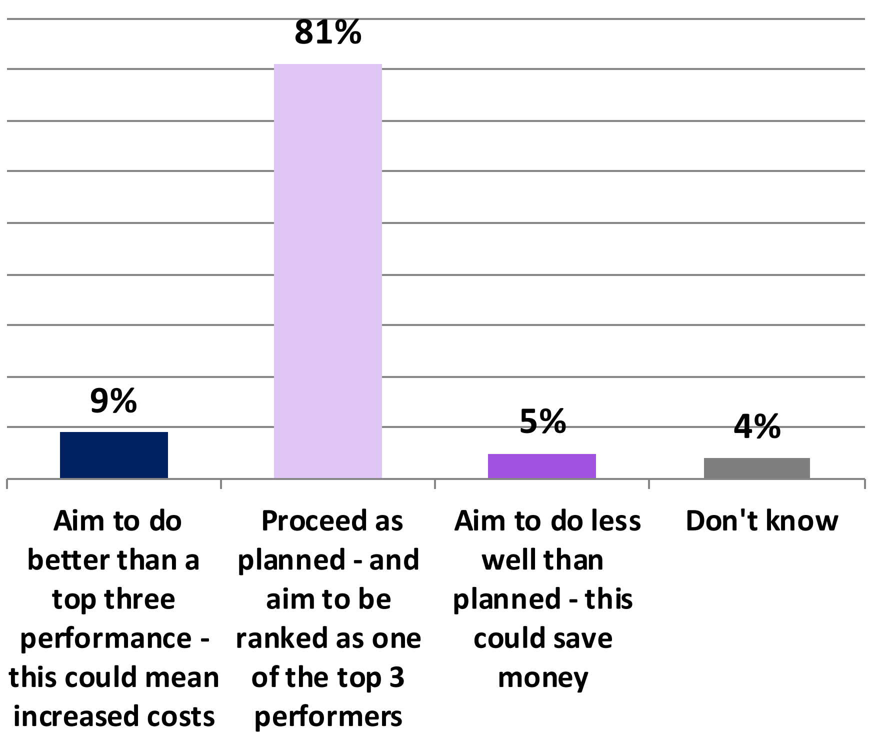
Actually do the work

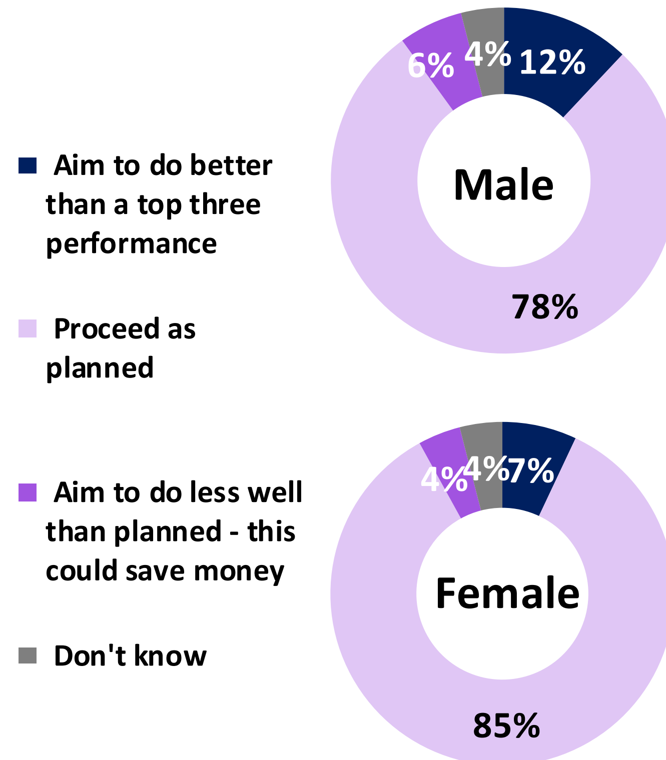


[Base 2014: 824]

The vast majority favour ENW's plan to be amongst the top 3 performers

Should Electricity North West…





[Base 2014: 824]

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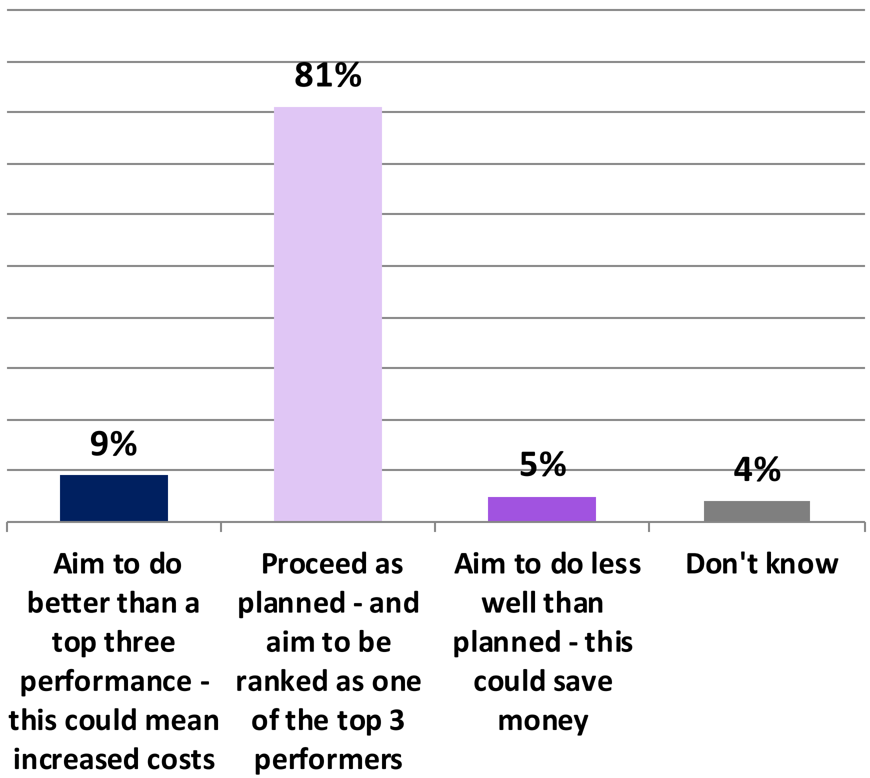


"You should always aim to be better."

"I personally think it's not worth it. Waiting a few more days for a non-emergency project to save money is fine."

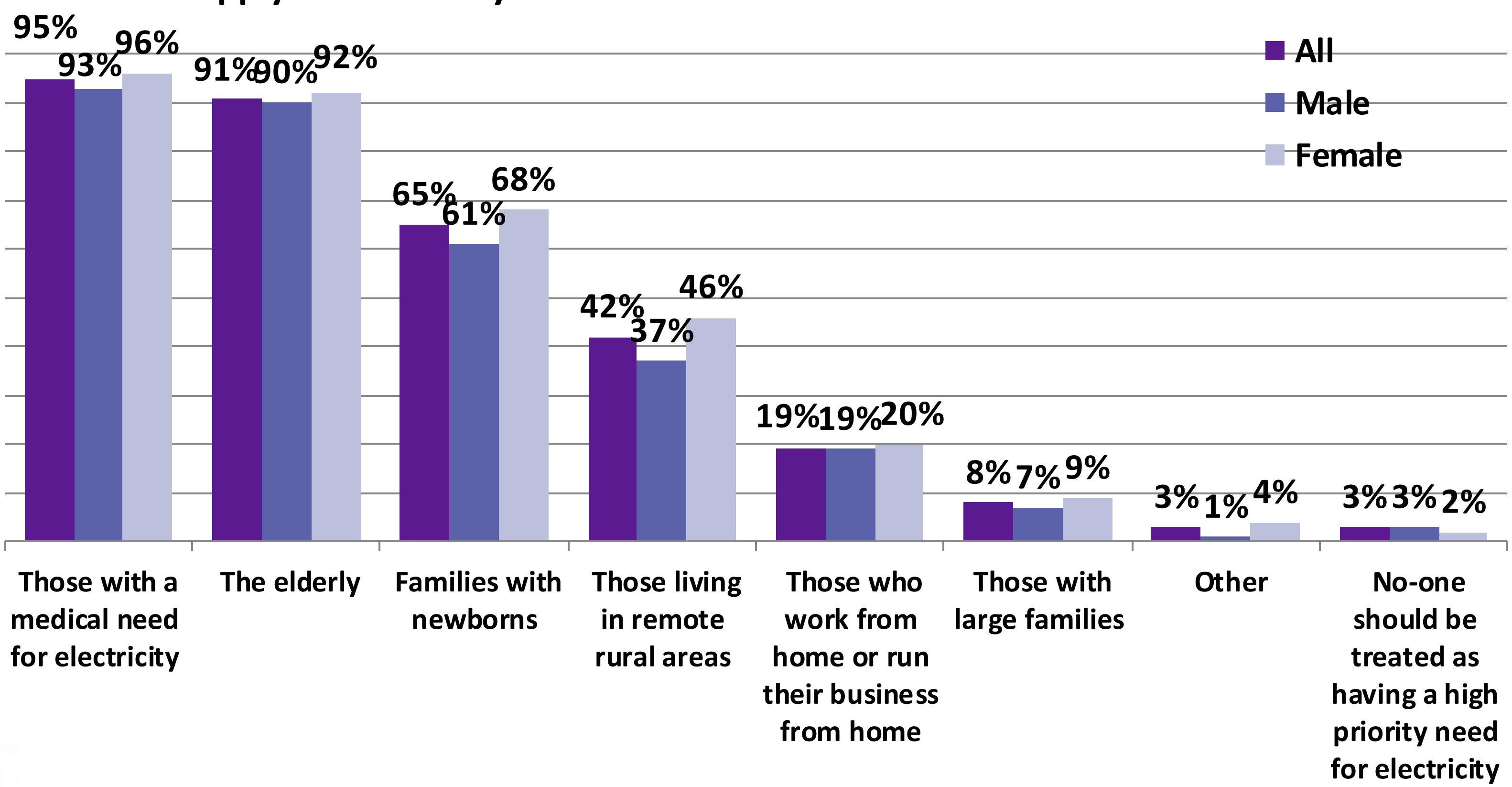
[Base 2014: 824]

Vulnerable Customers

electricity north west

Elderly and those with medical needs considered most vulnerable. Women more concerned than men about vulnerability of families and the 'rurally remote'

Which, if any, of the following groups do you believe have a particularly high need for a reliable supply of electricity?



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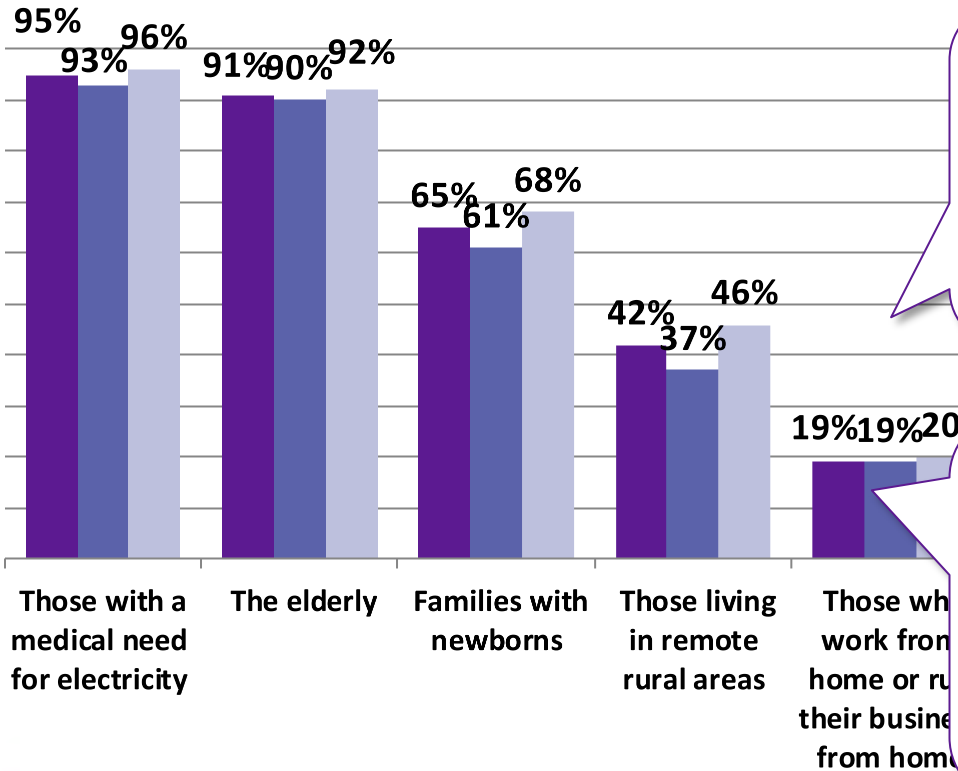


"Elderly people, especially those people that live on their own. And those people with young children".

"If somebody's on a ventilator at home obviously they need it because that battery is not going to last forever."

[Base 2014: 824]

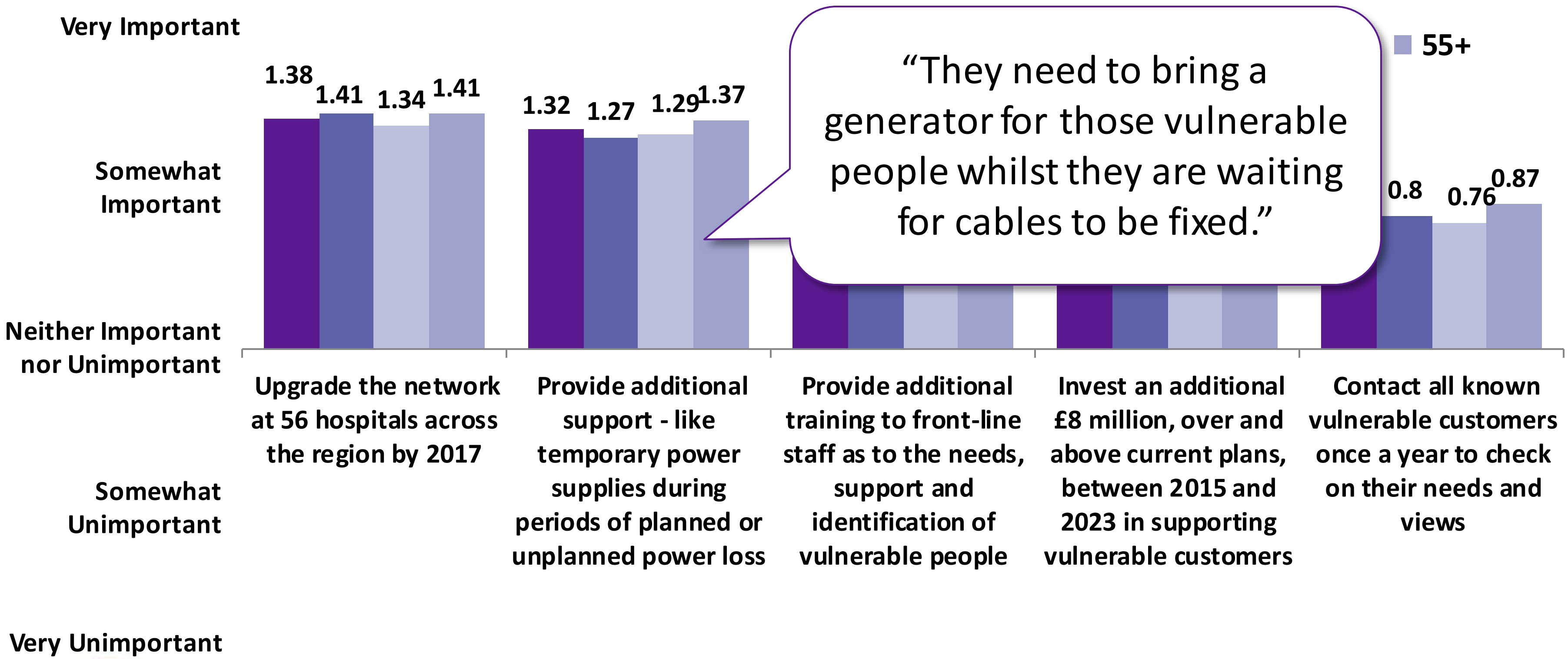
Most important support for vulnerable customers are hospital infrastructure and temporary power supplies during outages. Over 55s are most concerned about supporting the vulnerable

Please say how important or unimportant you think it is for Electricity North West to do each of the following. (Average rating)

[Base 2014: 824]

Most important support for vulnerable customers are hospital infrastructure and temporary power supplies during outages. Over 55s are most concerned about supporting the vulnerable

Please say how important or unimportant you think it is for Electricity North West to do each of the following. (Average rating)

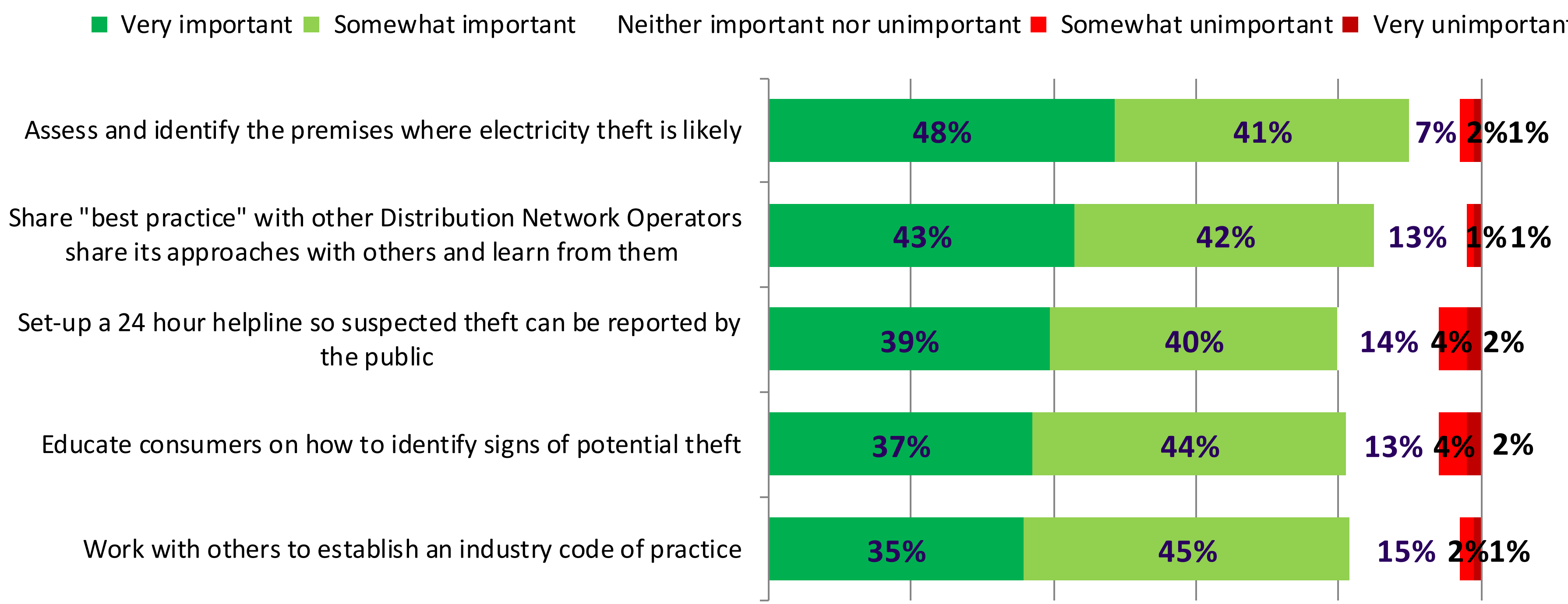


[Base 2014: 824]

Electricity Theft

Each element of ENW's plan to combat electricity theft is considered important – especially assessing/identifying premises where theft is likely

For each of the following possible actions, please say how important or unimportant you think it is for Electricity North West to do each of the following.



[Base 2014: 824]

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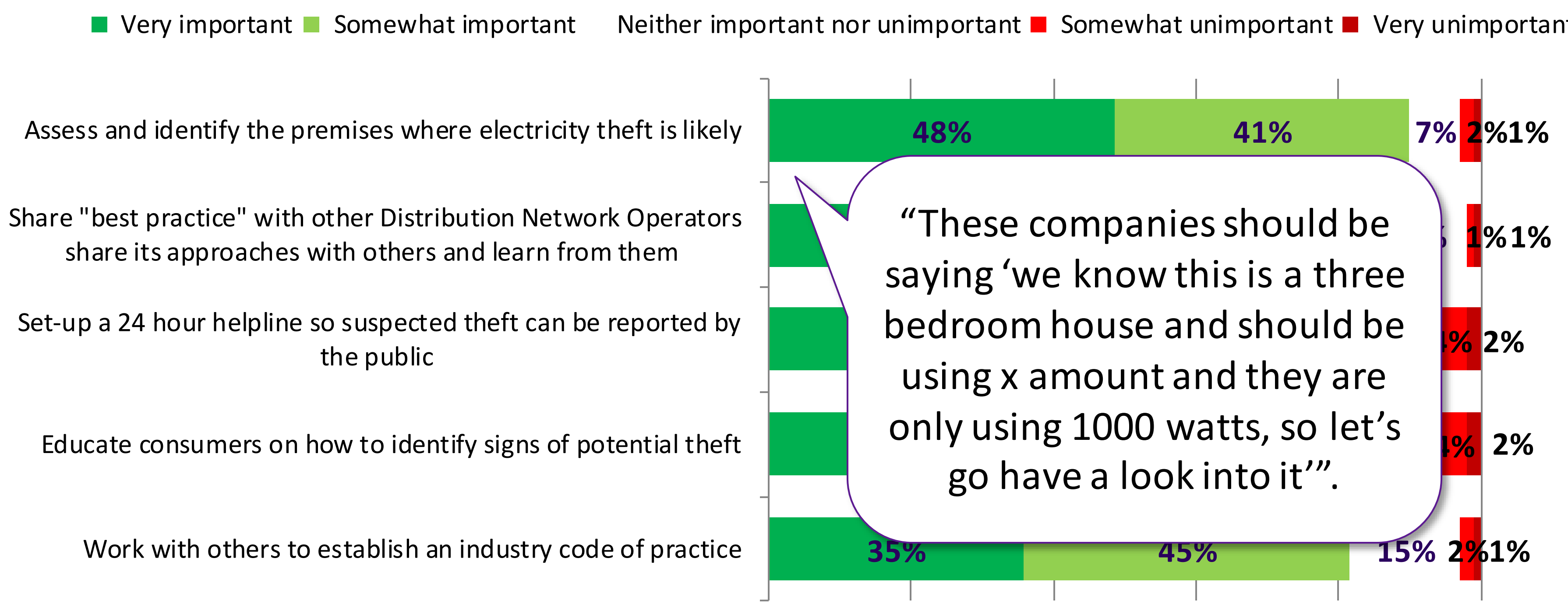
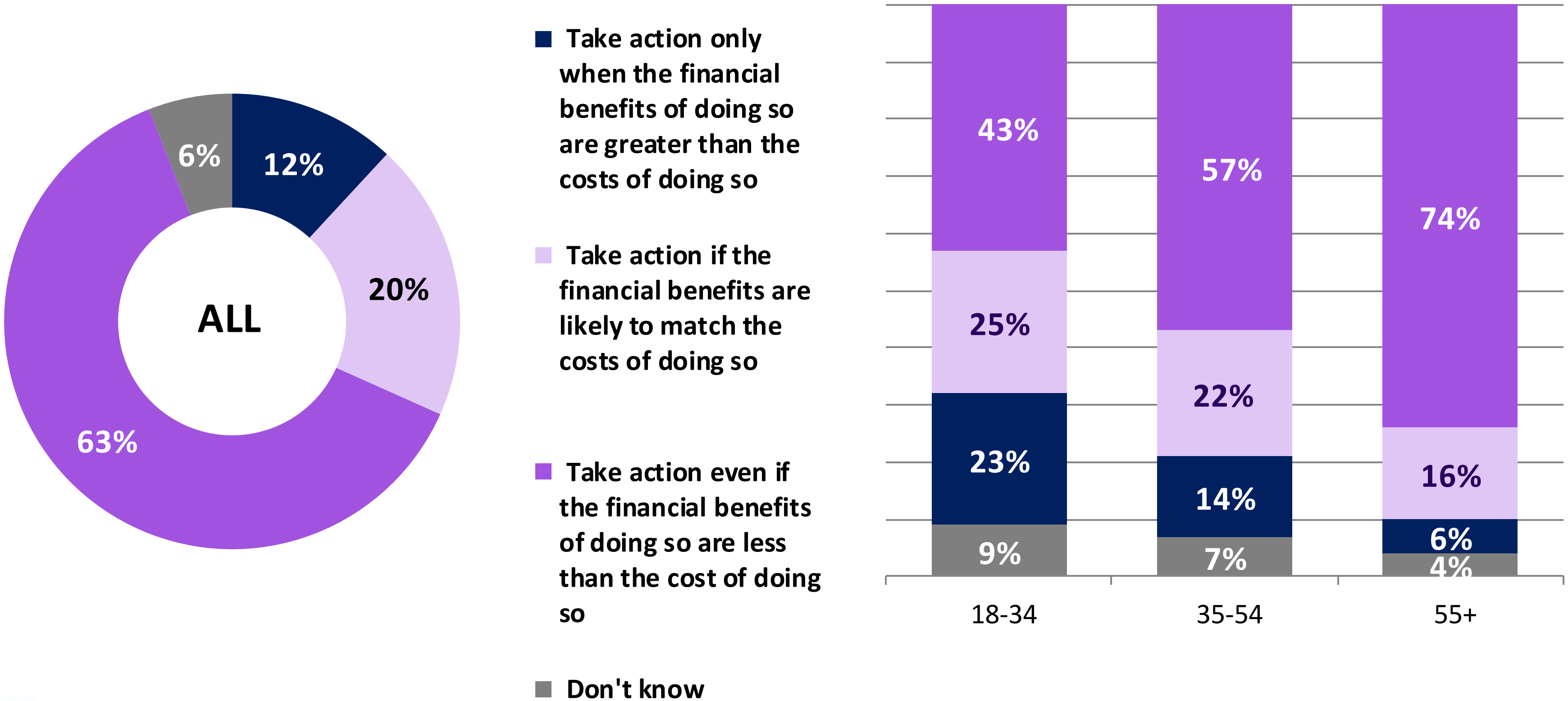


[Base 2014: 824]

The call for action on electricity theft – even when costs outweigh financial benefits – increases with age

Thinking about Electricity North West's general approach to tackling electricity theft, should they...?



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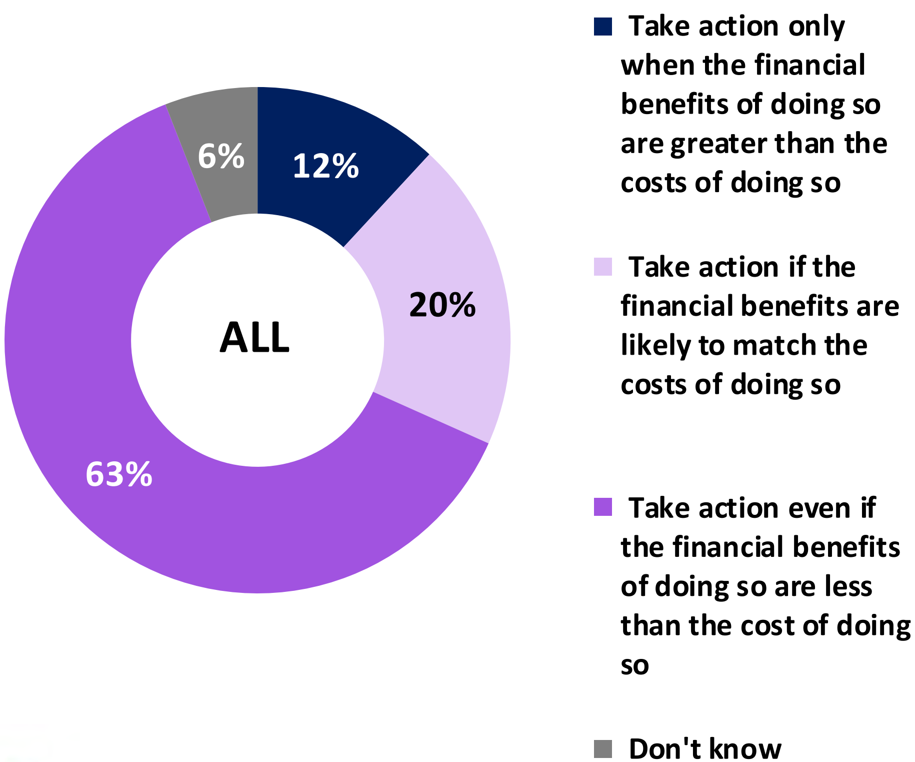


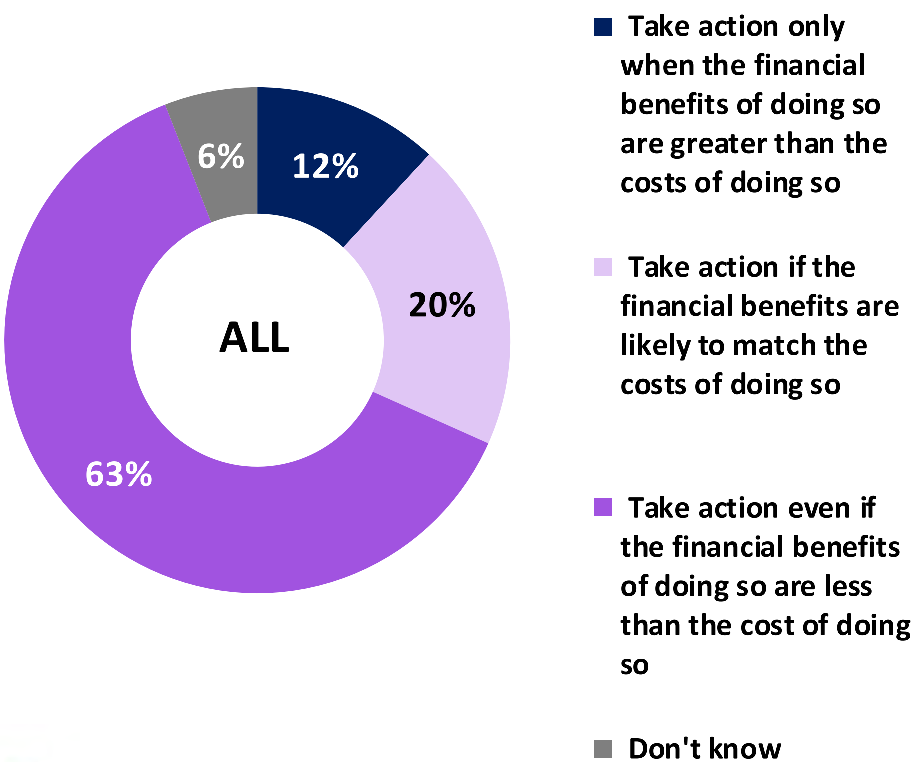
"They have got to stop people doing it at the end of the day, and they will save money doing so in the long run."

"They need to take action because not only do you have the theft of the fuel, you have the danger to the engineers and the people in the house."

[Base 2014: 824]

The call for action on electricity theft – even when costs outweigh financial benefits – increases with age

Thinking about Electricity North West's general approach to tackling electricity theft, should they...?



“It’s seen as a victimless crime and it isn’t; it spoils it for everybody.”

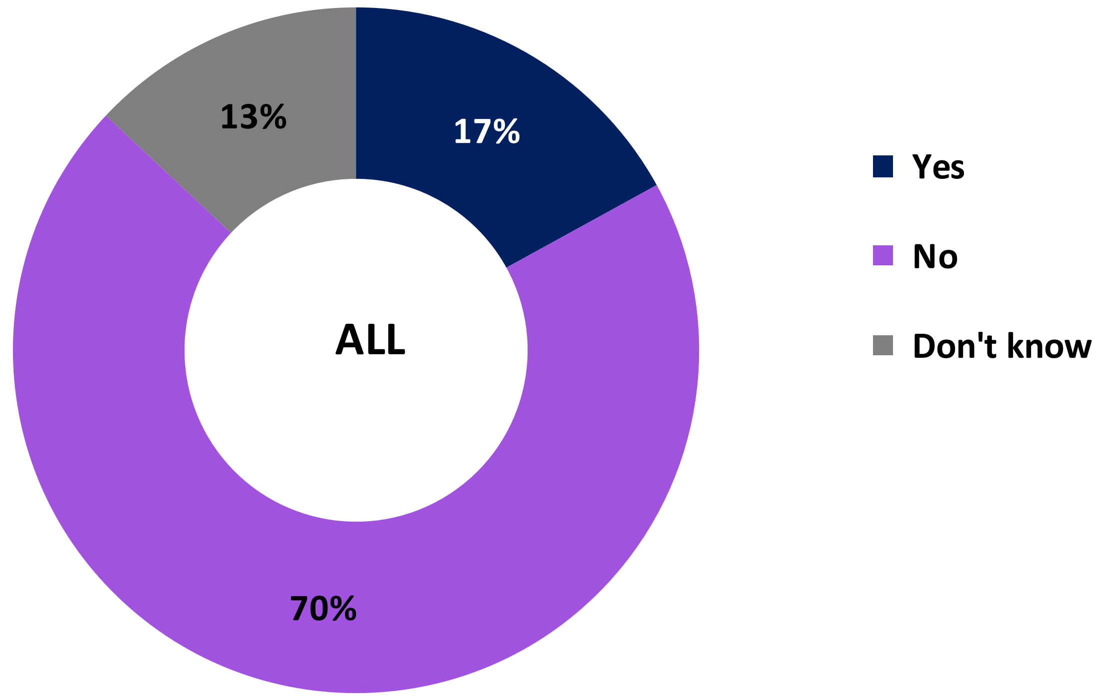
“You shouldn’t go looking for it; it’s going to cost money to do that. I don’t want to spend good money after bad.”

[Base 2014: 824]

Storms and compensation for power outages

There is little appetite for increasing current compensation levels if it means an increase in electricity bills

Keeping in mind that increasing the level of compensation payments is likely to raise the costs of all electricity customers slightly, do you think the compensation level should be higher than £54 after 18 hours without power?



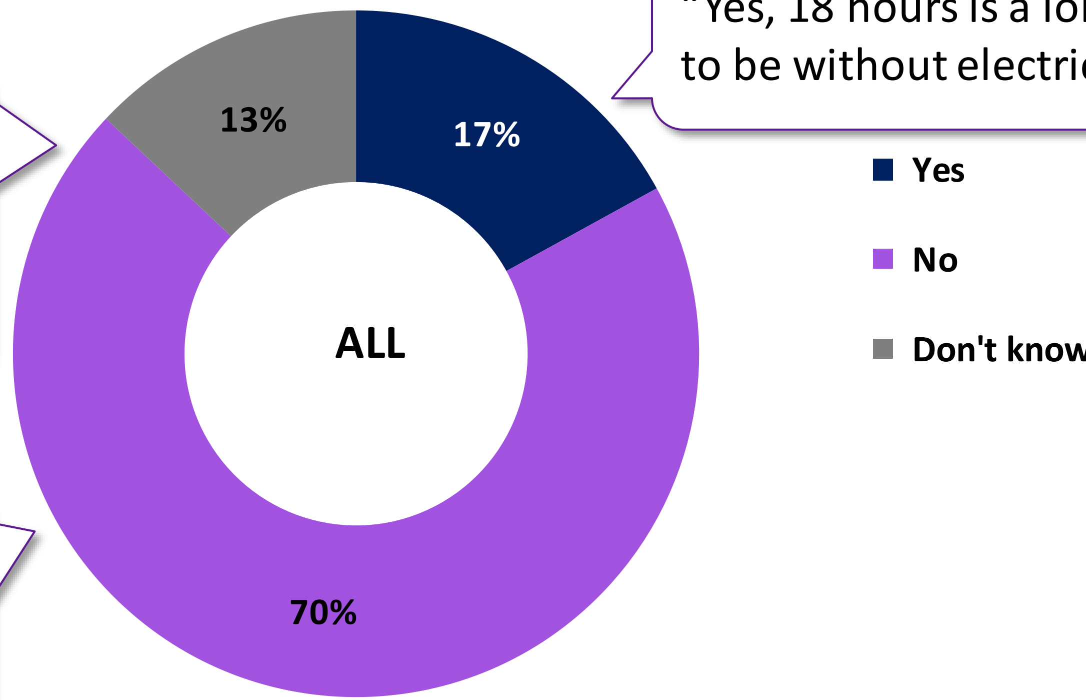
[Base 2014: 824]

There is little appetite for increasing current compensation levels if it means an increase in electricity bills

Keeping in mind that increasing the level of compensation payments is likely to raise the costs of all electricity customers slightly, do you think the compensation level should be higher than £54 after 18 hours without power?

"Yes, 18 hours is a long time to be without electricity."

"'As long as everything's been maintained as it should be and they can prove that then you can't blame them and expect compensation."

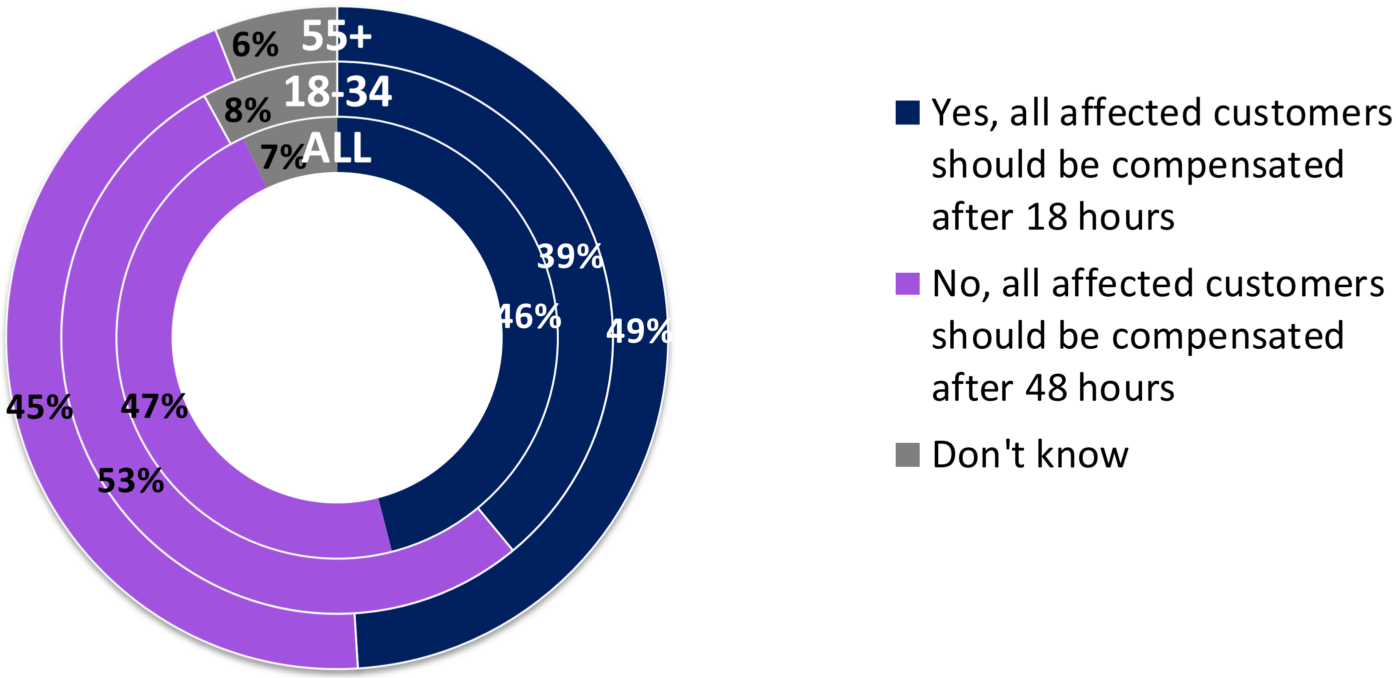


"I think culpability must come into it. If they are culpable then fair enough they should pay compensation."

[Base 2014: 824]

Appetite for paying compensation after 18hrs rather than 48hrs is split with 18-30s leaning slightly toward 48hrs and over 55s, towards 18hrs

Keeping in mind that increasing the level of compensation payments is likely to raise the costs of all electricity customers slightly, do you think that all customers affected by extreme weather should be paid compensation after 18 hours rather than 48 hours?



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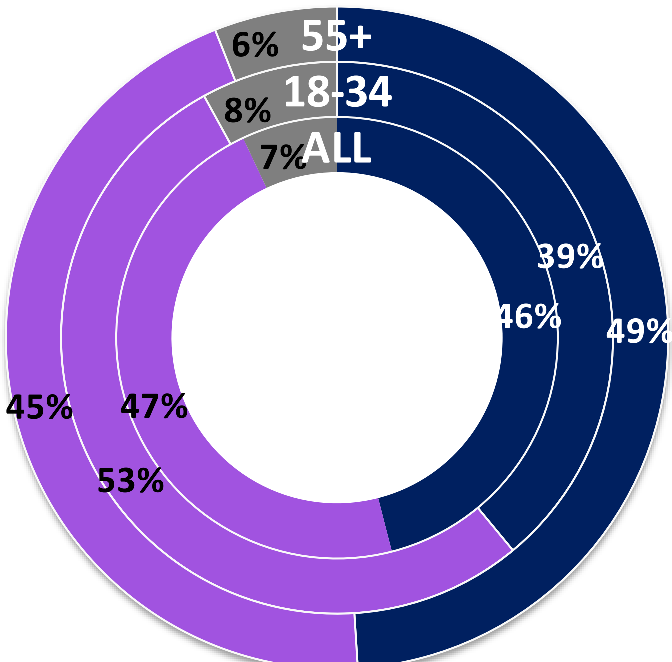


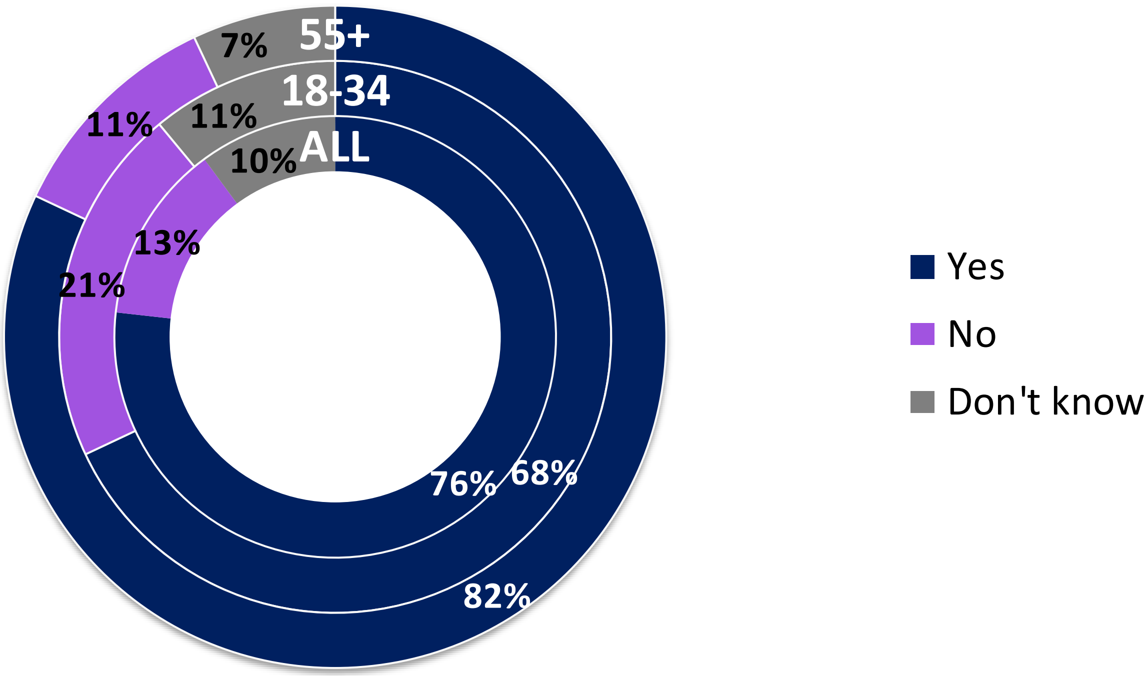
"No, it's not their fault what's happened and I do believe that the utility companies do their best, so at the end of the day I don't think it should change."

"The storm could last longer than that, and you don't want people outside putting themselves in danger fixing it."

[Base 2014: 824]

Most say that compensation should be the same irrespective of the number of customers affected, though 18-30s are less sure

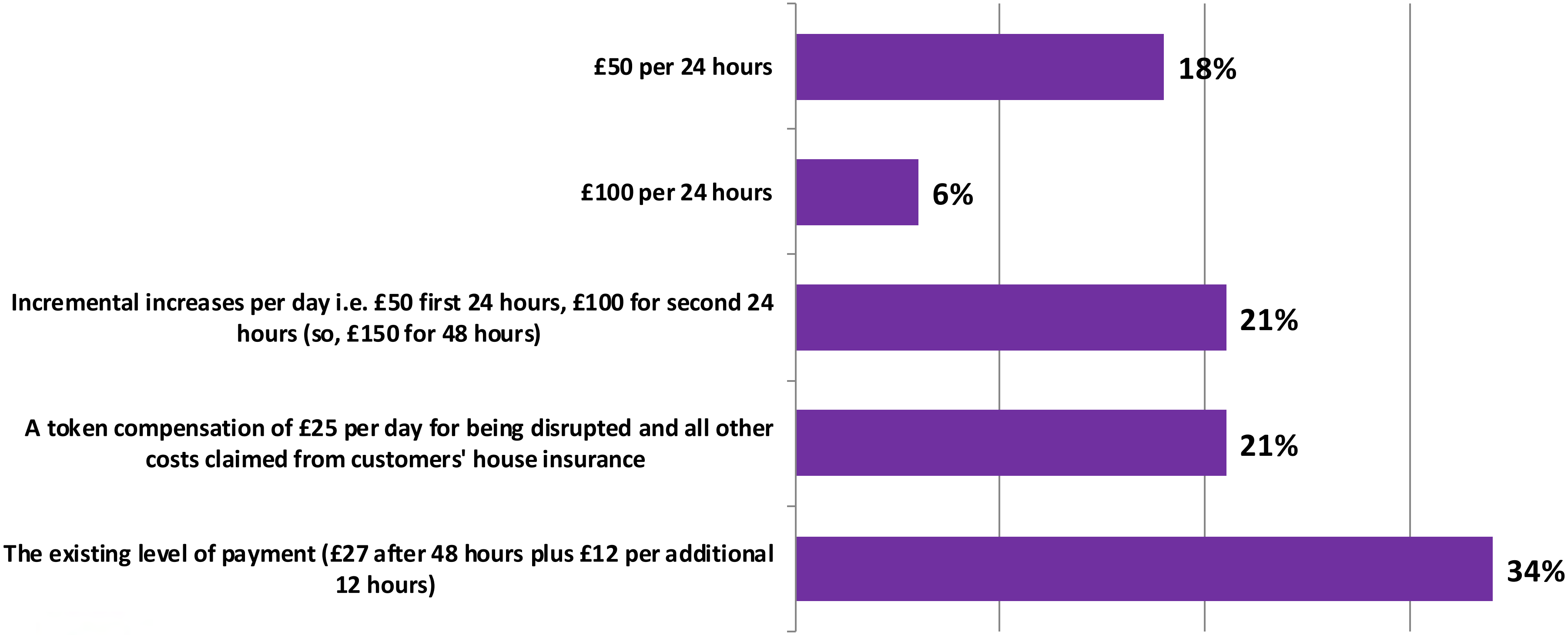
Should compensation be the same irrespective of how many customers are affected?



[Base 2014: 824]

While a third of consumers are happy with current compensation levels after extreme weather, nearly half favour an increase of at least £50 per day

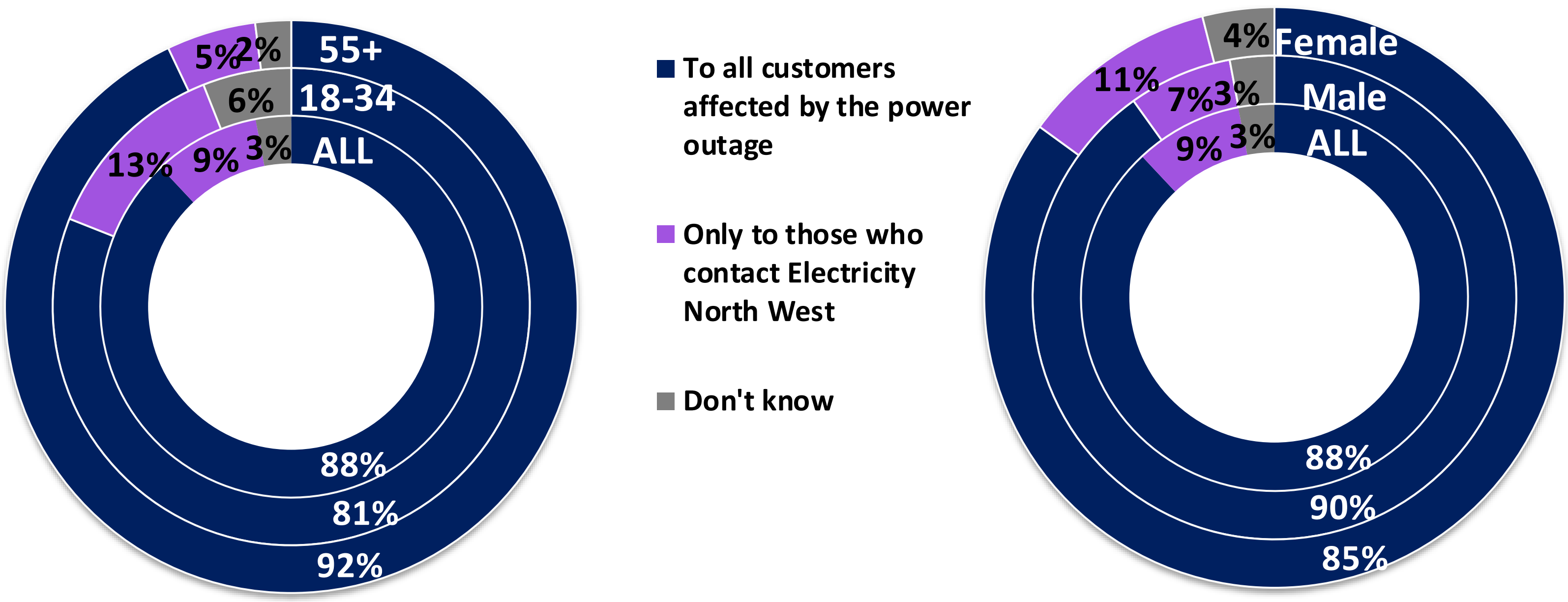
Which of these levels of compensation do you think would be most acceptable after being without power after an extreme weather event?



[Base 2014: 824]

The vast majority (especially over 55s and women) say compensation should be paid to all affected by the outage

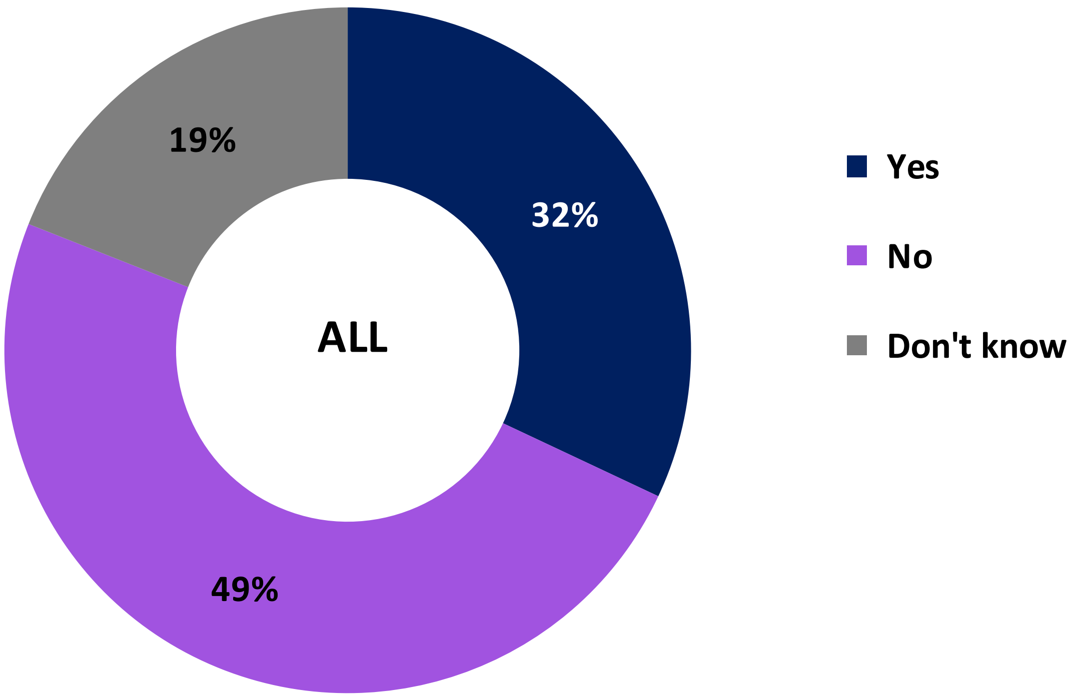
Should compensation be paid...?



[Base 2014: 824]

Half are against compensating business customers for total loss of earnings

Keeping in mind that increasing the level of compensation payments is likely to raise the costs of all electricity customers slightly, do you think all business customers should be recompensed for total loss of earnings?

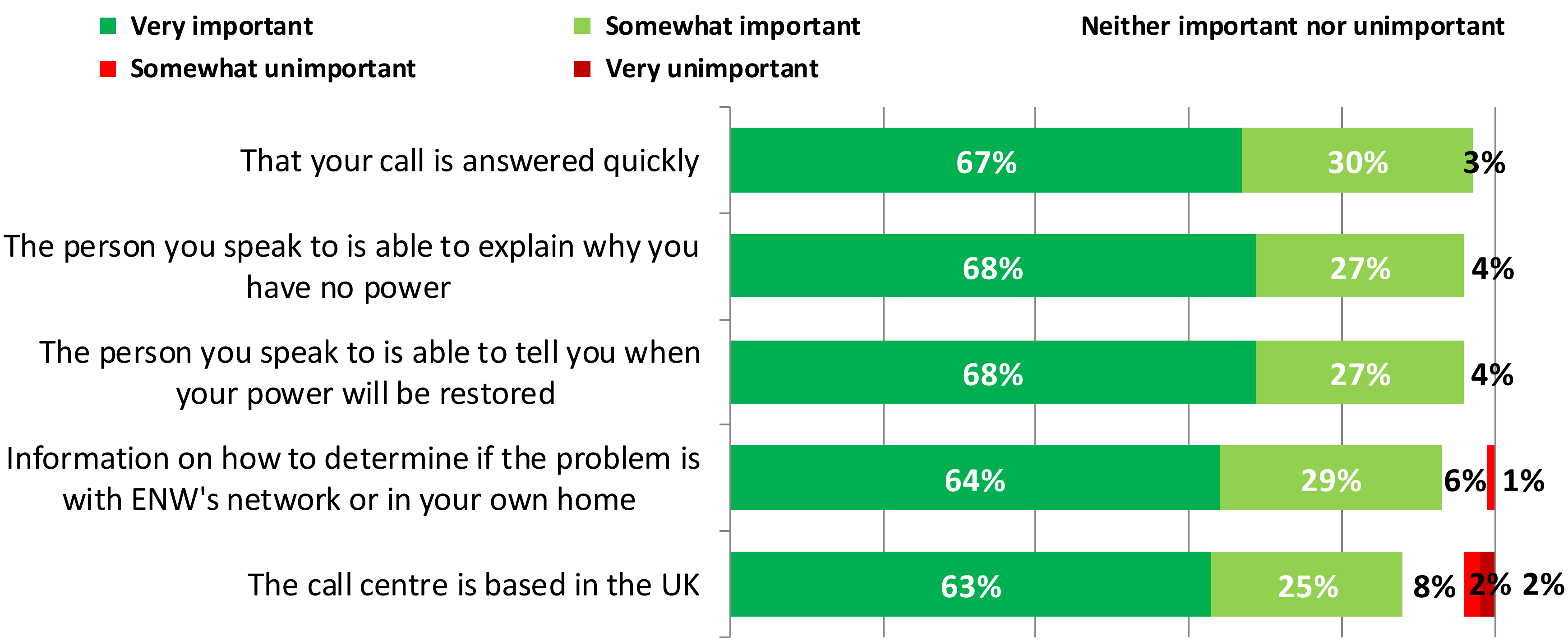


[Base 2014: 824]

Providing Information/ Social Media

Over half say that these service areas are very important when reporting a problem to ENW

If you were to call Electricity North West to report a problem, how important or unimportant would each of the following be?



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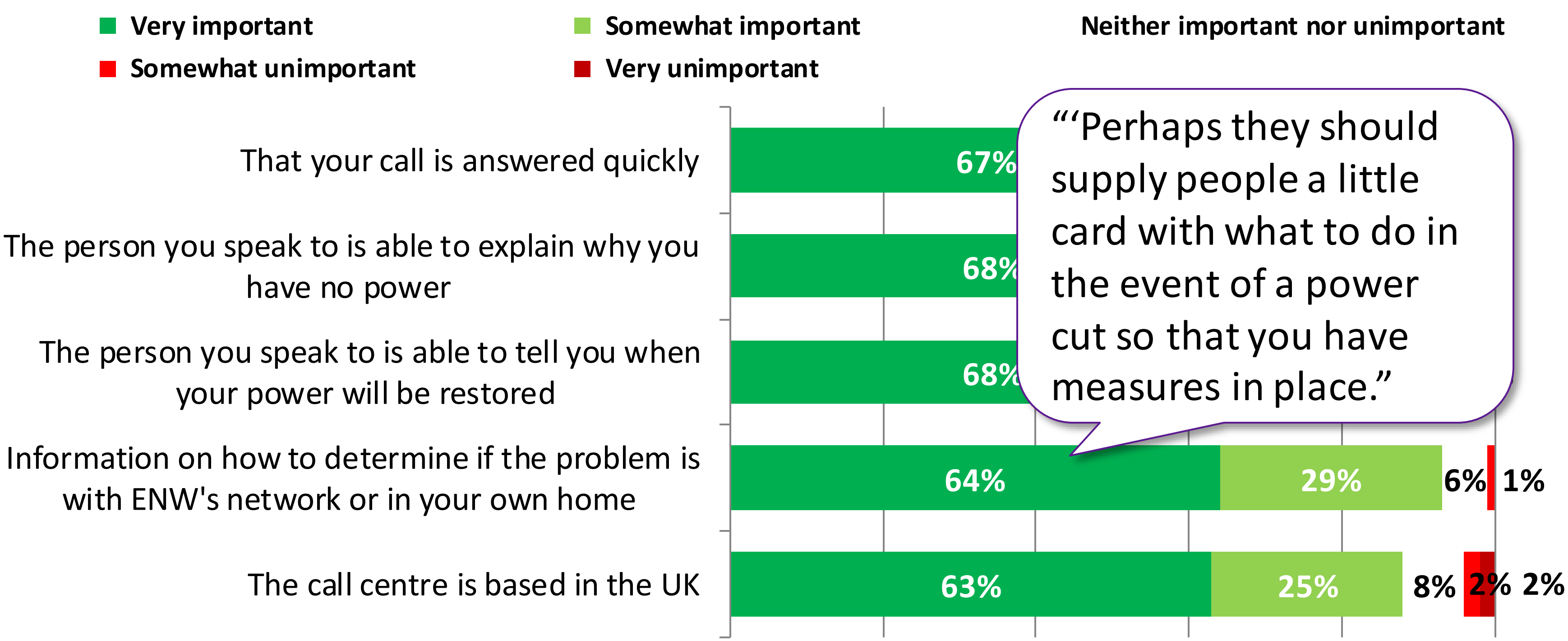
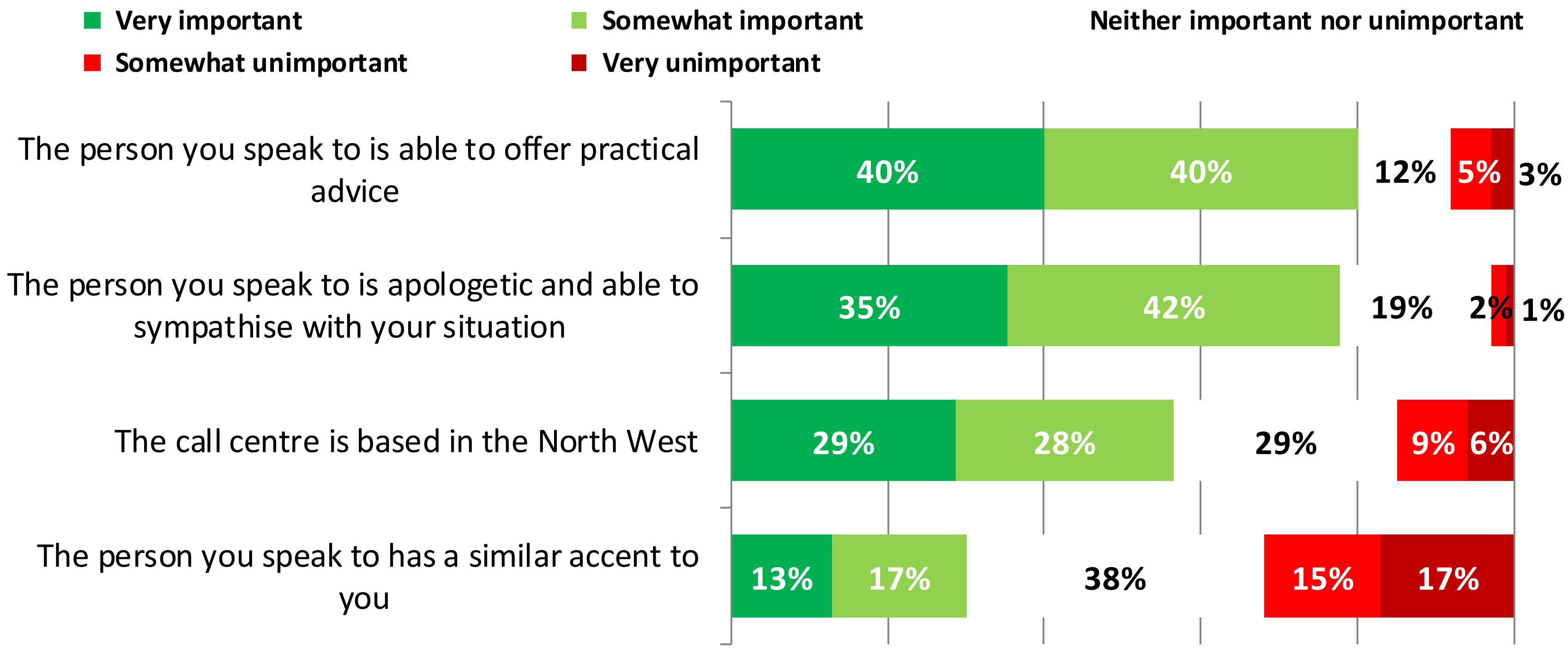


[Base 2014: 824]

Accent is the only service area that is considered more unimportant than important

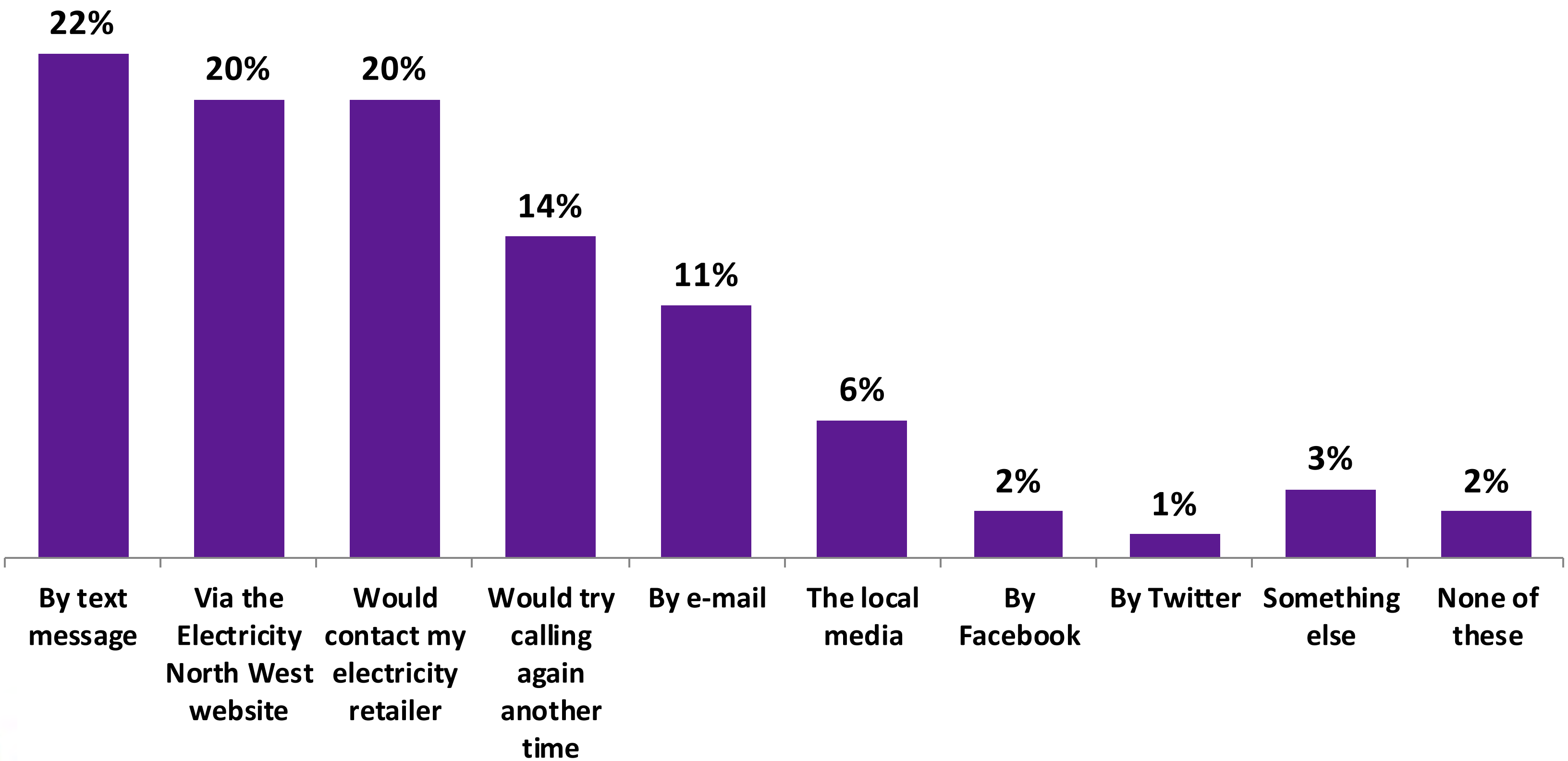
If you were to call Electricity North West to report a problem, how important or unimportant would each of the following be?



[Base 2014: 824]

Text and the ENW website are the most likely alternate means of contacting ENW about a problem. Facebook and Twitter are low priorities

If you were without power and you weren't able to speak with Electricity North West, because the phone lines were busy or the phone lines were down, how else might you try contacting Electricity North West or finding out about the problem?



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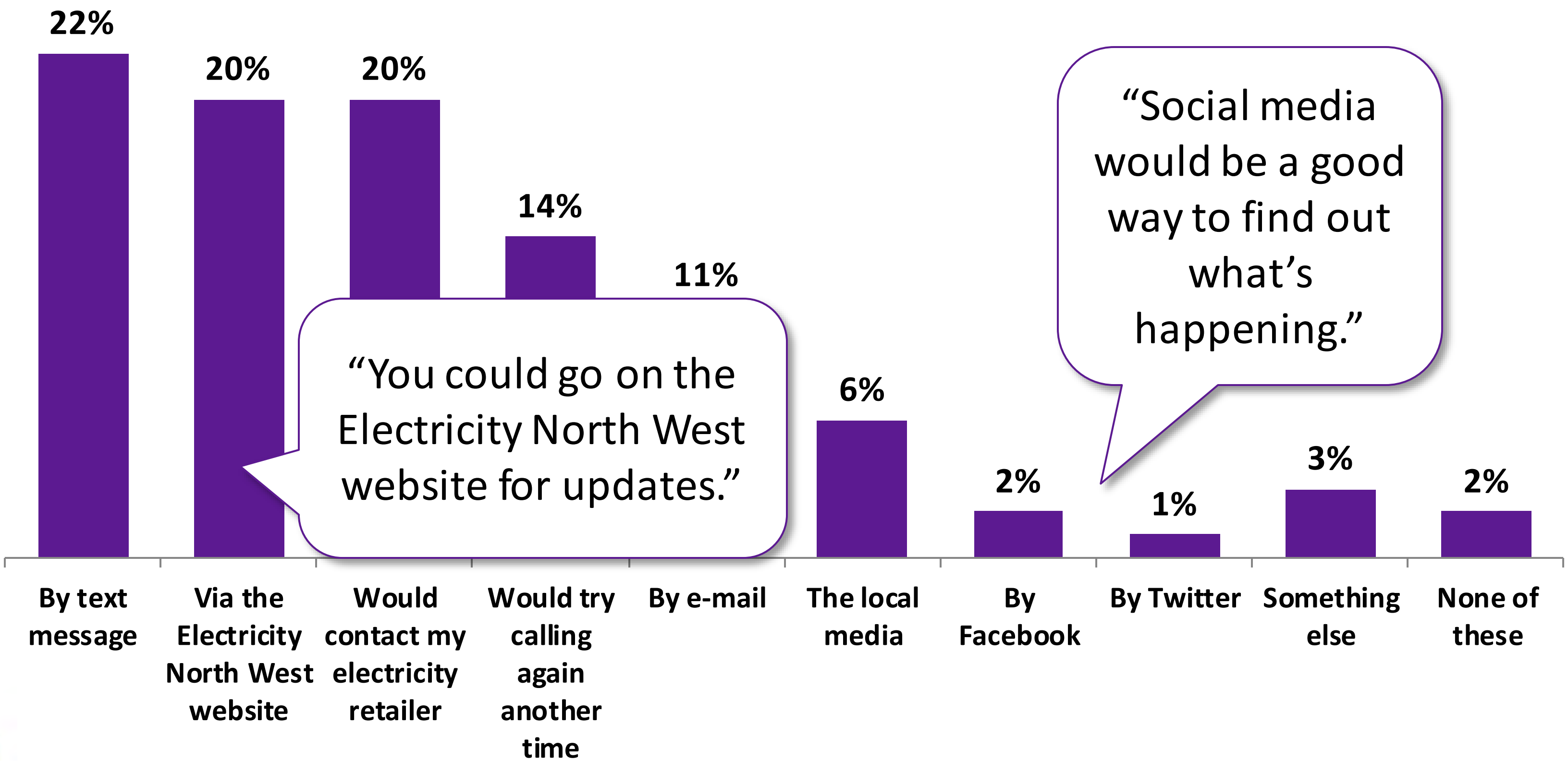
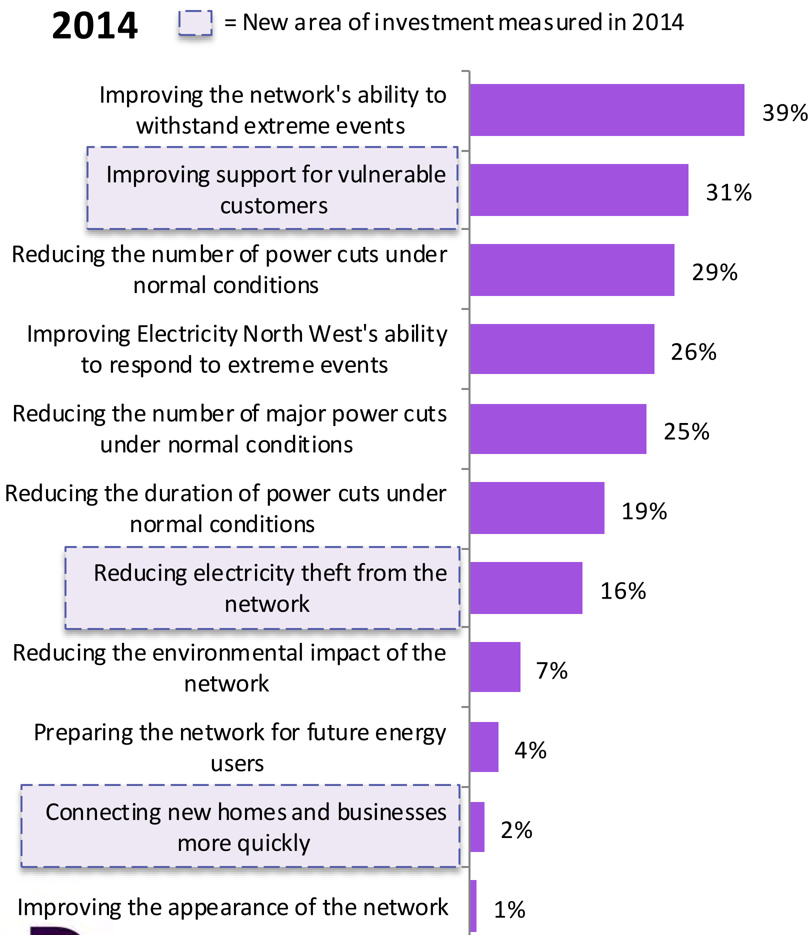


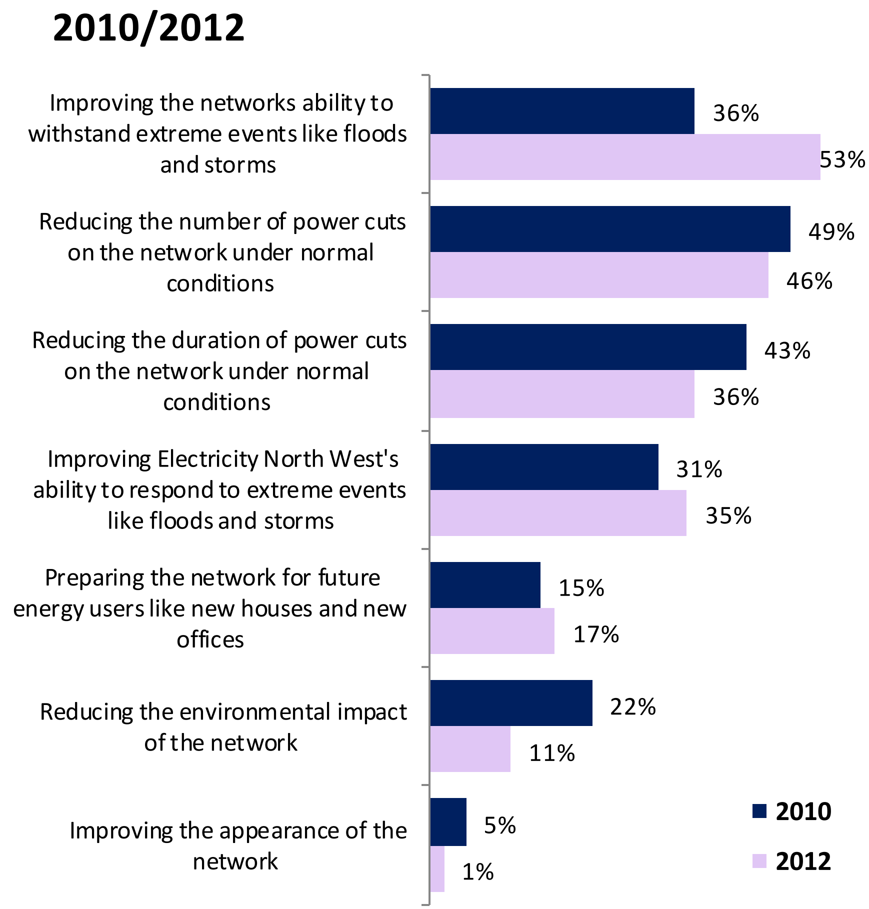
[Base 2014: 824]

Investment

While 'keeping the lights on' remains the key priority, supporting vulnerable customers is also important

Please rank the areas of investment (Most or second most important)

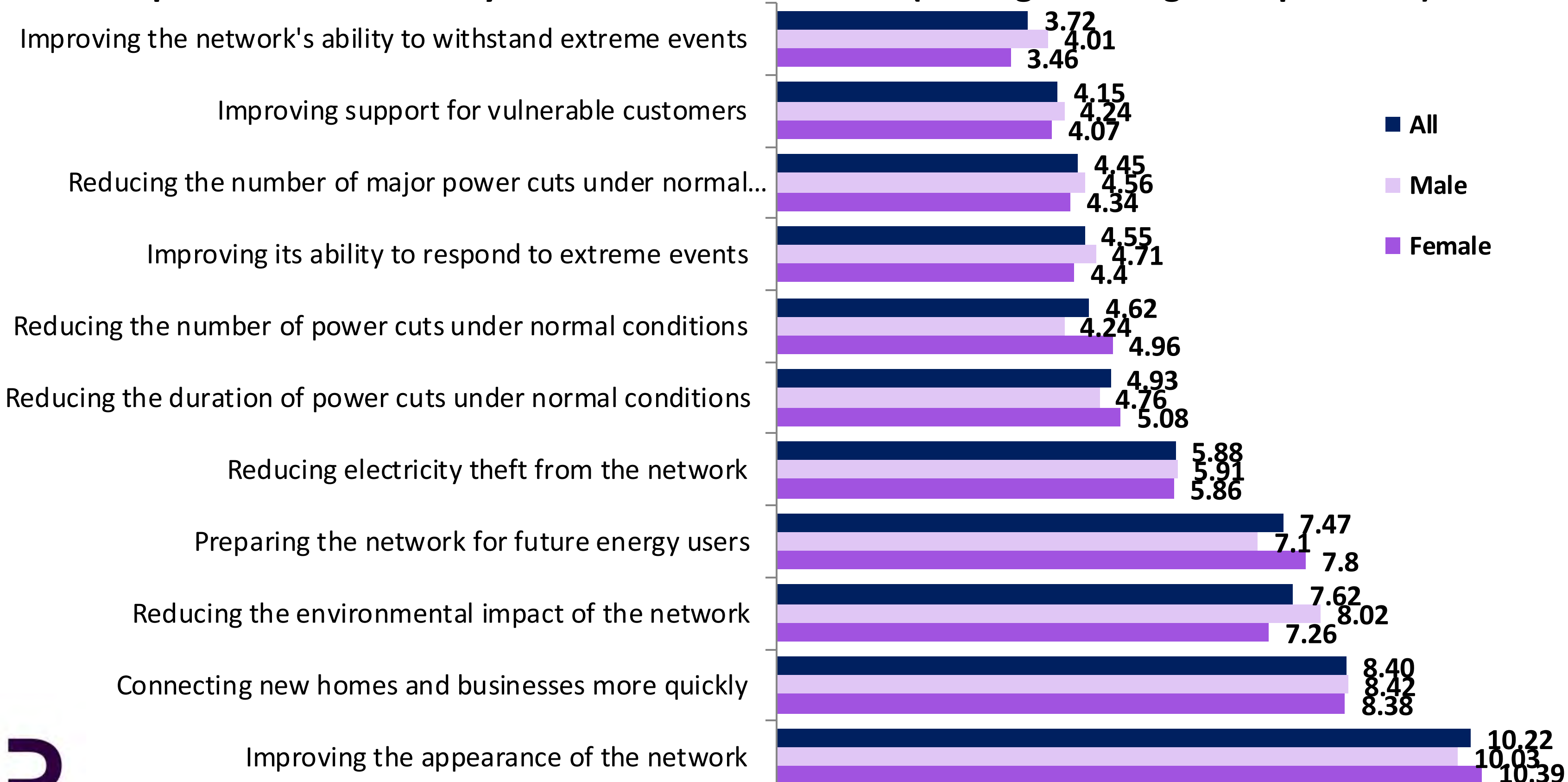




[Base 2014: 824]

Women place a higher priority than men on investment relating to extreme events, the vulnerable and the environment

Please rank the areas of investment, starting with the area you think it is most important for Electricity North West to invest in and working to the area where you think it is least important for Electricity North West to invest in. (Average ranking of importance)



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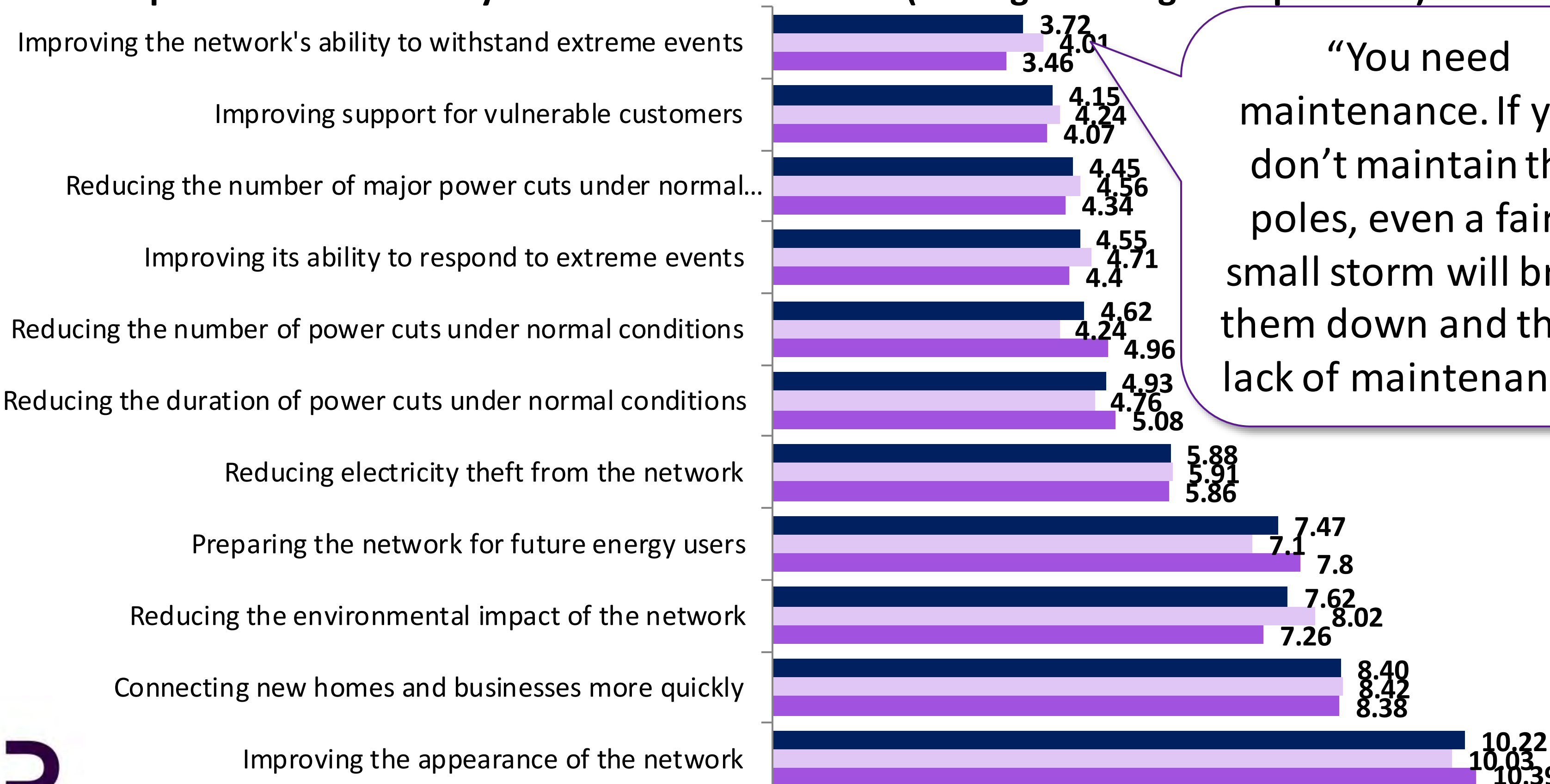
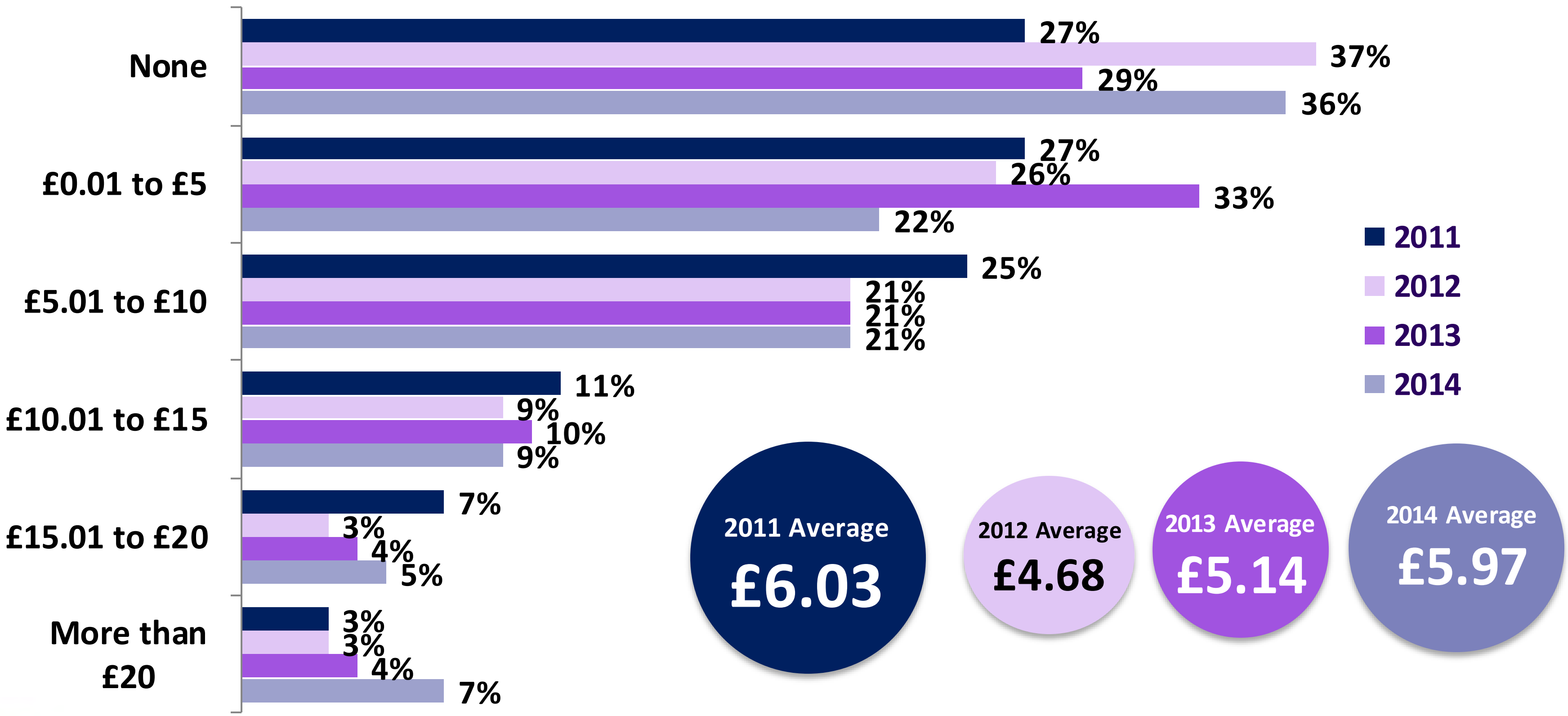


"You need maintenance. If you don't maintain the poles, even a fairly small storm will bring them down and that's lack of maintenance."

[Base 2014: 824]

Consumers are prepared to pay about £6 extra to fund investment

How much extra, if anything, would you be prepared to pay in your electricity bills per year to fund additional investment?



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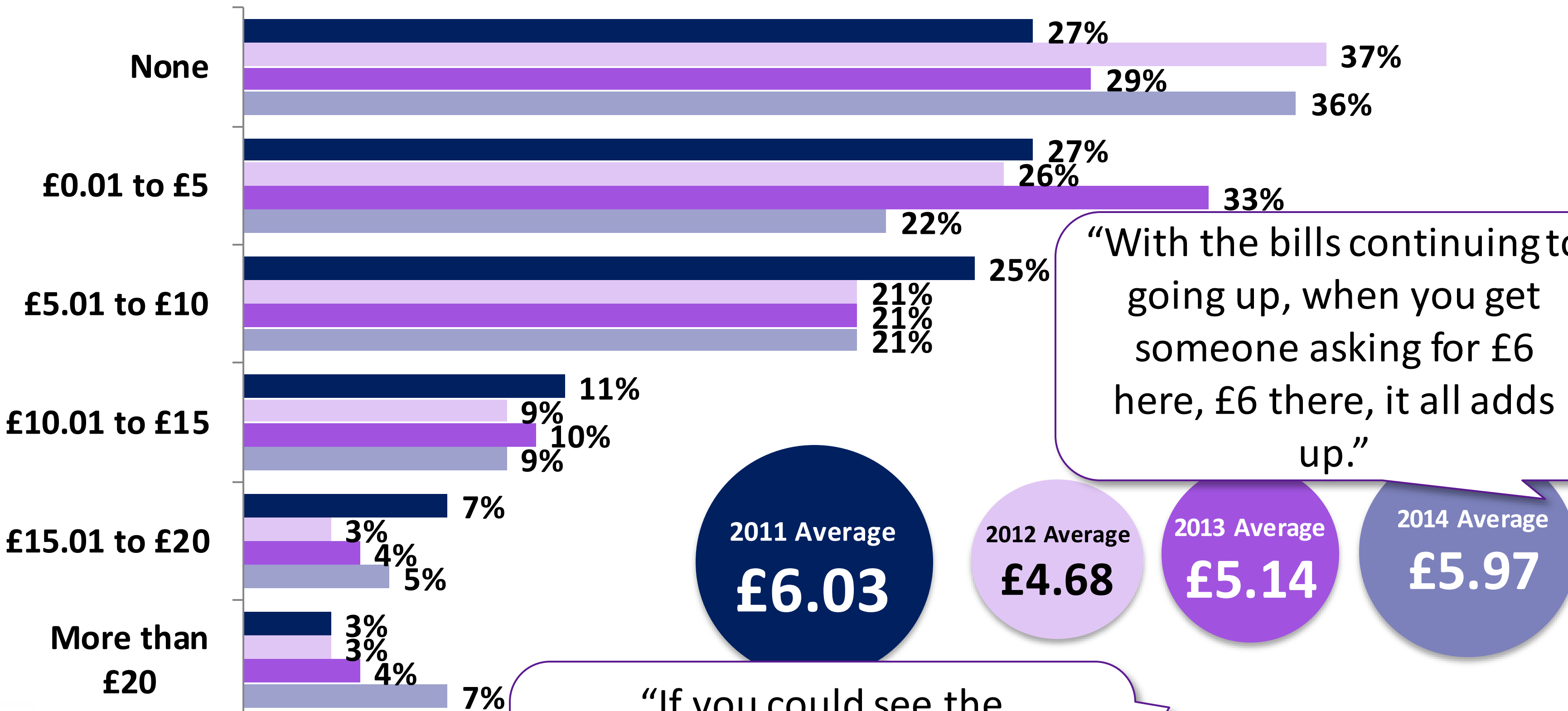


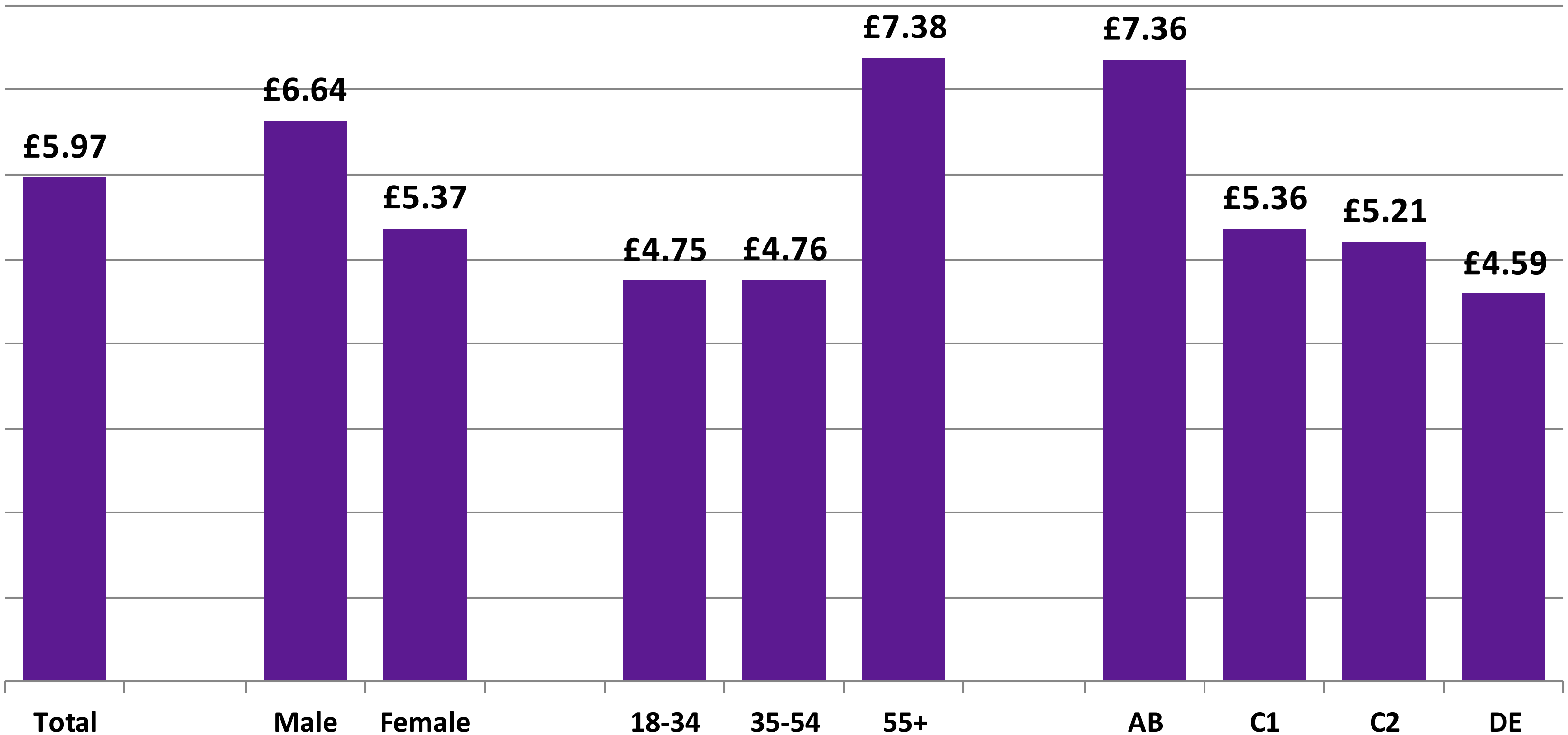
"With the bills continuing to going up, when you get someone asking for £6 here, £6 there, it all adds up."

"If you could see the improvements they are making, then yes I would be willing to pay extra."

[Base 2014: 824]

Over 55s and men tend to be more willing to pay extra than younger people and women

How much extra, if anything, would you be prepared to pay in your electricity bills per year to fund additional investment?

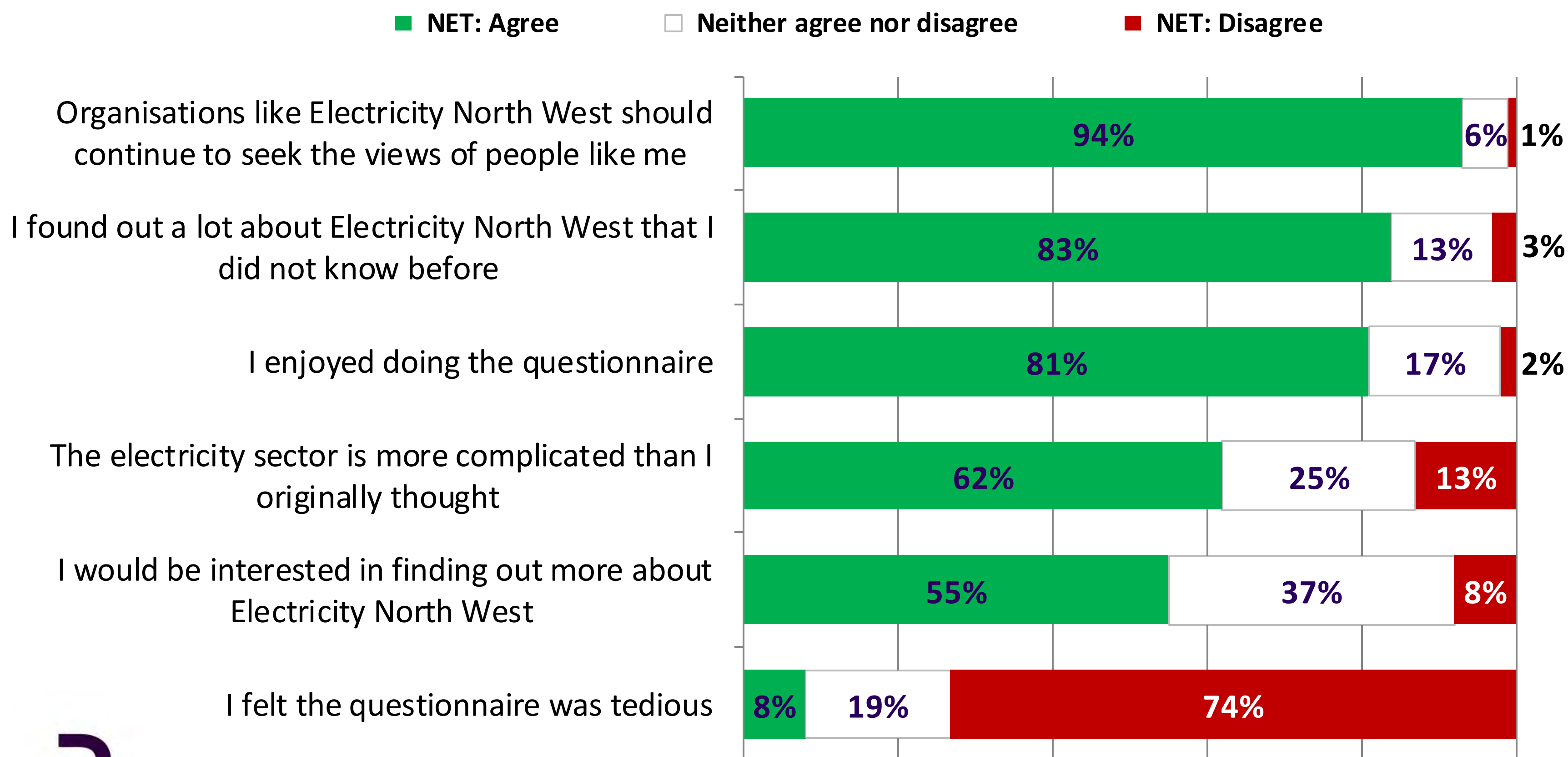


[Base 2014: 824]

Research Administration

Four in five found out a lot about ENW and enjoyed participating in the research

To what extent do you agree or disagree with the following statements about this investigation of Electricity North West and the electricity sector?



[Base 2014: 824]

Appendix

Methodology

Populus interviewed 914 adults aged 18+ online between 24-27 January 2014. All respondents lived in the area served by Electricity North West and were recruited to reflect the demographic profile of the region. All were offered briefing material explaining what ENW does and its role in the electricity sector and were asked six questions to ensure that they had read the material and understood it. Those that were able to answer correctly at least five of these questions answered the questions as 'Engaged Consumers'.

This is the fourth wave of research and comparisons, where made, are to 2010, 2011 and 2012 research.

Populus is a member of the British Polling Council and abides by its rules.

Populus conducted two focus groups with those who had completed the online survey in central Manchester on the evening 5 January 2014.

Briefing Material

Introduction

Electricity North West plays a vital role in the North West region. We own, operate and maintain the electricity network; delivering energy to our 2.4 million customers and have a strong track record in safety and reliability.

During the next five years we will be investing over £1bn in the network; supporting the North West's economy growth, providing jobs and supporting the move to a low-carbon economy.

As with any successful business we have great people working in Electricity North West who care passionately about providing excellent service to our customers and which we will continue over the coming years.

Steve Johnson
CEO Electricity North West

Key facts

Electricity North West owns the North West's electricity distribution network and operates, maintains, constructs and repairs the network.

Electricity North West operates under a licence from the regulator Ofgem to distribute electricity through its network of 13,127 km of overhead lines, 43,126 km of underground cables and 38,332 transformers to around 2.4 million homes and businesses in the North West.

Focused on delivery
As a regulated Distribution Network Operator, Electricity North West is focused on the efficient delivery of electricity and network reliability to our customers and on delivering an economic return to our shareholders.

Substantial investment
Electricity North West is a significant contributor to the North West's economy, with a substantial R&D spend and a key role in enabling regional economic development. Between 2010-2015 Electricity North West plans to invest over £1bn in the region's infrastructure including £200m for new connections, £120m to reinforce the network and £420m to replace assets at the end of their operational lives.

Stakeholder engagement
Electricity North West has an ongoing programme of engagement with stakeholders across the region to help focus on the region's key requirements and ensure our future investment plans have minimal visual and environmental impact.

Future developments
Electricity North West contributes to a low carbon environment. We will continue to invest in the North West's electricity network to maintain the current excellent level of reliability and to meet the future energy needs of our customers through the development of low-carbon, environmentally-friendly solutions.

electricity north west

Our area of operation incorporates Greater Manchester, the counties of Lancashire and Cumbria and parts of Derbyshire and Cheshire.

Electricity North West Limited
304 Bridgewater Place
Birchwood Park, Warrington,
Cheshire WA3 6XG
Phone: +44 (0)1925 846999
Fax: +44 (0)1925 846990
Email: enquiries@enwl.co.uk

For further information please visit our website:
www.enwl.co.uk

electricity north west

Briefing Material

Populus

Dear Valued Opinions Panellist,

Thank you for agreeing to take part in this survey.

We're really interested in find out what people living in the North West – people like you – think of some of the issues facing the electricity industry.

Before you answer the last questions, we'd like to tell you a little more about the electricity industry and, in particular, how it works in the North West.

Please read the two documents (this one, plus one more) you've been sent before answering the following questions. Without reading this material, you may find it difficult to answer these questions.

Thank you in advance for taking part in our research – we're looking forward to hearing your views.

The Populus Team

Who's Who in the UK's Electricity Industry?

There are many different types of companies and organisations involved in supplying you with electricity.

- **Generators** are companies that run the UK's power stations and generate our electricity. The UK's electricity comes from many different sources – nuclear, gas, wind farms and others – and these power stations are spread across the UK.
- **The National Grid** is responsible for operating some of the power lines in the UK – the most powerful ones – and transmitting electricity from power stations to closer to where people live and work. The National Grid is a little like the UK's motorway network. The National Grid does not connect your home or place of work to the electricity network.
- **Distribution Network Operators** – sometimes called DNOs – connect the National Grid's network to individual homes, offices, and other buildings. They link the National Grid with your home: a little like the UK's 'A' and 'B' roads and local roads. The DNOs maintain many of the UK's electricity wires and cables. Each region of the UK has a DNO allocated to maintaining the electricity network in that area.
- **Suppliers** are the final step in the process and are the people who send you bills for your electricity, some of them – like EON, EDF and NPower – you may have heard of. Some of the money you pay your supplier is passed to Generators and DNOs to cover their costs in supplying you with electricity.
- **Ofgem** is the official regulator of the energy industry. Its job is to regulate (or manage) the electricity industry. It tries to ensure you get a good service at a reasonable cost – while making sure investment goes into the UK's energy network and allowing the private companies involved to make a modest profit.

Introducing Electricity North West

Populus

Electricity North West is the Distribution Network Operator – or DNO – for the region in which you live. They are also the company who have asked Populus to conduct this research.

What Does Electricity North West Do?

Electricity North West manage and maintain the electricity distribution network – consisting of overhead lines, underground cables, transformers, sub-stations and other equipment – across the North West. This network supplies 2.4 million people in major cities like Manchester, Carlisle, Blackpool and Lancaster, as well as smaller towns and rural areas.

Electricity North West ensures the day-to-day running of the system in the North West, repairs the network when things go wrong (if overhead power lines are damaged by storms, for example) and invests in the network to replace worn out or old parts. Electricity North West is also responsible for making sure the network can cope with any changes in how electricity is used.

Electricity North West's network is 99.99% reliable. A typical home in the North West will experience one power cut every two years and, on average, is without power for about an hour a year. These figures are only averages: some homes will experience problems more often, while some people will never have problems with their power supply.

Electricity North West is responsible for connecting your home to the electricity network. They are responsible for the connection as far as your fuse box. Your fuse box and wiring within your home is not the responsibility of Electricity North West.

But I've Never Heard of Electricity North West!

In many ways, Electricity North West is a 'behind the scenes' company.

Electricity North West do not send you a bill for their services. Instead your supplier passes on part of what you pay them to Electricity North West. About £110 of the typical yearly household electricity bill goes to Electricity North West to cover their costs in managing the network.

You may have dealt with Electricity North West if you've had a problem, like a power cut, with your electricity supply. Electricity North West runs a call centre you can report power cuts or other power supply problems to, and it is normally Electricity North West's engineers who will fix or repair any problems.

You might have had contact with Electricity North West if you've ever built an extension to your house and needed your connection to the electricity network changed (for example, the cables connecting your house to the network moved). You may have seen Electricity North West vehicles and staff around the North West conducting maintenance works to the energy network.

Why Are We Asking Questions About Electricity North West?

On the next page we've outlined some of the issues and challenges facing Electricity North West. As well as experts inside the company thinking about these issues, they want to get the views of normal people who live in the North West.

Your answers to our surveys will be very important; you might help decide how much is invested in the network, how the call centre answers calls, whether Electricity North West does more to reduce its environmental impact, or even how much people are charged for electricity!

Issues and Challenges Facing Electricity North West

Populus

These are just some of the issues Electricity North West faces and we'll be asking you questions about these. *We've put in italics some questions you might like to start thinking about now.*

Investment

There are lots of different ways Electricity North West can spend money on the electricity network.

It can build a network better able to withstand storms and floods.

Or a network that is more reliable on a day-to-day basis. Or build in protection against terrorist attacks or vandalism.

But all these investments cost money.

Which is the most important to you? Would you be prepared to pay more to have all three? What else could Electricity North West invest in?

Changes in how power is used

One of Electricity North West's jobs is to predict – and respond to – changes in how electricity is used. If they get it wrong, there might not be enough capacity or supply in future or it might not be in the right places.

More electric cars, for example, might mean an increase in demand over night as these charge. *What other changes can you imagine?*

One possible change is Electricity North West having greater control over appliances in your home. *Would you be happy for Electricity North West to switch off your fridge or freezer for a short time if this prevented a total power cut?*

High priority customers

Electricity North West, and Ofgem, believes that some people – with medical needs, older people, in very remote areas – are harmed by power cuts more than others. Electricity North West tries hard to restore power to these people quickly. *Are you in one of these groups? Is it right that some are prioritised over others?*

Fixing your supply if it goes wrong

One of Electricity North West's most important jobs is repairing and fixing things when they go wrong, like getting your power back on if it goes off for some reason. Electricity North West has to balance the need to get things done quickly with the need to do them safely.

What type of information do you want during a power cut? How should you be kept informed?

Should you receive compensation or a discount if your supply is off for a long-time?

Is it better they restore some power quickly – enough to light your house, but not cook or use the washing machine – or switch all the power back on at the same time?

Community involvement

Electricity North West – via its power lines, sub-stations, and other equipment – can be found in many communities across the North West.

How important is it that Electricity North West keeps its buildings clean and graffiti free? Should Electricity North West go into schools to talk about electricity?

Visiting your home

Sometimes Electricity North West might need to enter your home or garden to fix a problem.

Should Electricity North West make a particular appointment with you, or should they just come as quickly as possible?

Answering your telephone calls

When things go wrong with your supply, it is Electricity North West you call to report a problem.

What's the most important thing for Electricity North West to do when they answer your call? Would you rather contact Electricity North West online or via an App on your phone?

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SUB-ANNEX A11: Extraordinary External Stakeholder Panel meeting minutes, January 2014

Extraordinary External Stakeholder Panel meeting: Business Plan Resubmission

Wednesday 29 January 2014, 10:00–13:00

Attendees
Stakeholders:
1. Andrew Faulk, Policy Manager, Consumer Futures
2. David Haughian, Nuclear Strategic Programme Coordinator, Cumbria County Council
3. Daniel Storer, Director of Business Development, MIDAS
4. Bev Taylor, Energy Manager, Bruntwood

Electricity North West
1. Steve Johnson, Chief Executive Officer
2. Paul Bircham, Regulation Director
3. Alex Moore, Head of Communications
4. Jonny Morgan, External Communications Manager

Apologies:
1. Morgan Donnelly, Engineer and Project Manager, Wind Prospect
2. Stephen Hagerich, Emergency Response Development Manager, British Red Cross
3. Helen Heggie, Director, STEMFirst
4. David Messenger, Biopower Plant Engineering Manager, Iggesund
5. Lorraine Donaldson, Project Manager, National Energy Action

RIIO submission overview

SJ gave update on the original submission to Ofgem and feedback we've had and explained our understanding of reasons why our plan was not fast-tracked. Also explained process for resubmission.

PB thanked panel for input so far, emphasising that one of the key elements of our plan to offer reduced bills early (which has since been taken on by all DNOs) came directly from input from the panel on our affordability and price profiling discussions.

BT praised Electricity North West's Condition Based Risk Management approach to asset management as a first class part of the submission in making the most of assets before replacing them.

AF commended Electricity North West's approach to stakeholder engagement and said it was one of the best he'd seen.

Connections
Proposal to revise down our targets for time to quote and connect

PB said we want to be leading, however being such an outlier brings risk and cost into the business. Is it acceptable to reduce our targets but still deliver excellent performance?

BT – From a commercial perspective, there is no need to have very short times to quote and connect due to lengthy planning processes.
DS – There are a number of large strategic sites and small businesses in Greater Manchester that he is currently engaging with our connections team on to find the best approach but timings are not currently an issue
AF – Consumer Futures recently responded to a European consultation on this issue and agreed that for householders 10 days to quote and 1 month to connect were acceptable timeframes, therefore they agree with our revised proposal. It would also be beneficial to provide information on the connecting process immediately when a request is received.

Vulnerable customers
Further detail to be included in plan on identification and services for vulnerable customers

AF – Electricity North West's approach is in line with that of other DNOs. It is important to prioritise customers and situations, and provide tailored services depending on customers' needs. A DNO should not only know who is on the priority services register, but why they are on it, eg, do they use a stair-lift? DNOs should phone vulnerable customers regularly – perhaps once a year – to check on their status.
DS – Agree on checking regularly with customers and having a flexible approach to vulnerability and services.
AF – It is important to invest in the network around care homes due to the high concentration of vulnerable customers.
DH – Agreed to pass the questions on to relevant colleagues at Cumbria County Council for their view, particularly on vulnerable customers.

Electricity theft
To what lengths should we go to tackle electricity theft?

BT – Very important to tackle it.
AF – Important to offer our revenue protection services to small suppliers to help them compete. What does a DNO have to do? Important to have a clear line on where our social responsibilities end due to the cost to customers. Of course DNOs should help police tackle theft, but some funding, eg, funding thermal imaging cameras for police forces to help them identify cannabis farms (which are also likely to be bypassing their meters) may be a step too far.

Storm compensation
Should we set our own voluntary compensation rules, and at what level should they be bearing in mind potential costs to customers

BT – Very difficult question as it's all about balance.
AF – Important to take a wider view from consumers based on what they think is an acceptable rate. [ENWL agreed to do this through its Engaged Consumer Panel].
DS – Important that Electricity North West maintains the ability to use its discretion during extreme weather.

Other issues

DH – Agreed to a separate meeting following the next Stakeholder Panel (20 March) to discuss new nuclear issues in more detail
AF – Praised ENWL's stakeholder panel, including its small size as it gave real access to the business and its senior leaders for key stakeholders.

Issues for Panel to discuss at next meeting
- Stakeholder engagement vs customer service
- Brand awareness – importance, cost vs benefit
- UK-wide single number for power cuts
- Corporate Charity
- New nuclear stakeholder engagement

SUB-ANNEX A12: Specific endorsement from key stakeholders

SIEMENS

Infrastructure & Cities

Steve Cox
Head of Future Networks

Electricity North West Limited
Network Strategy
304 Bridgewater place
Birchwood Park
Warrington
WA3 6XG

Name	Kevin Tutton
Department	NWE RC-GB IC SG Smartgrid Division
Telephone	+44 (0) 115 906 6777
Fax	
Mobile	+44 (0) 7808 882 3978
E-mail	Kevin.tutton@siemens.com
Your letter of	
Our reference	
Date	27 March 2013

Siemens' support Electricity North West approach to Innovation: with specific focus on RIIO-ED1 Business Planning

Dear Steve,

Siemens is delighted to provide a letter of support which endorses the approach taken by Electricity North West towards Innovation under the RIIO-ED1 Business Plan.

Siemens own history, success and values are founded on the principle of innovation.

As a market leader providing products, services and solutions to the global electricity distribution market, we recognize the challenges faced by owners and operators of electricity networks – to ensure their network is secure, reliable and most importantly flexible to meet the needs of their Customers today, and in the future, in the most cost effective way possible.

Siemens has long worked together with Electricity North West, and particularly over the past two years, to understand the challenges faced by network companies, along with the range of solutions which can be employed to address the challenges.

Innovation is cultural

Siemens works closely with the distribution network companies as part of the Low Carbon Networks Fund. In doing so we observe that innovation is approached differently by each of the network companies; with Electricity North West innovation is more innate, with change coming from *within* the organization. It is evident that there is strong leadership, and a consistent approach towards innovation, with customer value at the centre – the focus is to leverage more from what exists where possible.

Breaking the mould

One of Electricity North West's key objectives is to be a thought leader – their approach towards innovation, challenge the current limits around regulation and operating standards, to deliver increased flexibility in the network, whilst ensuring value for money and minimum disruption to customers. This has been demonstrated in their successful Low Carbon Networks Fund Tier 2 submissions (i.e. C2C and CLASS) which address changes to existing standards and commercial arrangements, where learning and benefits are transferrable to other customers.

Siemens' Support

Electricity North West has sought input and views of many stakeholders, including Siemens, as part of their business planning for RIIO-ED1.

Innovation and how this relates to the effective delivery of outputs are a key focus – areas have already been identified for future consideration that will deliver value to customers. Engagement with customers and development of flexible networks and infrastructures, including smart cities, remain a common goal for both Electricity North West and Siemens.

Siemens has appreciated the open, collaborative approach that Electricity North West has taken towards innovation, which in turn has helped direct Siemens as we improve the products and services offered to the market.

We look forward to supporting and building upon the relationship with Electricity North West, as an innovation partner, as we move forward to address the challenges of creating flexible networks and value for customers that RIIO-ED1 will pose.

Yours sincerely,

Kevin Tutton
UK Divisional Lead – Smart Grid

GREATER MANCHESTER POLICE

Chief Inspector Rachel Buckle
Operations Lead TNS
Specialist Protective Services

Steve Cox
Electricity North West
Linley House
Dickinson Street
Manchester
Greater Manchester
M1 4LF

Date: 3rd March 2014

Dear Steve,

The Approach to Metal Theft & Electricial Substation Security within Electricity North West

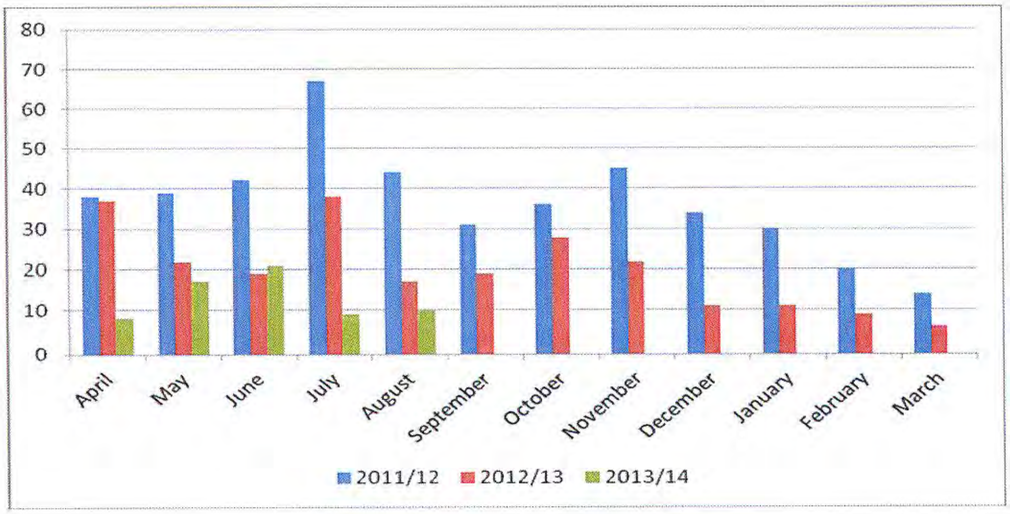
Greater Manchester Police launched Operation Alloy in 2011 to deal with an increase in metal theft. Officers have worked relentlessly alongside the scrap metal industry, local authorities and victims of metal theft to target offenders and this has led to a 78.4% reduction in this type of crime.

In December 2012, Operation Alloy implemented the Legal Aid Sentencing and Punishment of Offenders Act which took cash out of the industry. The following year the Scrap Metal Dealers Act 2013 was introduced which required all sites and collectors to be licensed.

Operation Alloy has worked tirelessly with victims of metal theft and this has been the key factor in reducing metal theft. Working with these victims we have introduced unique marking techniques to make property traceable. We have also introduced recognised asset disposal routes.

Electricity North West Limited was identified as the largest individual victim within Greater Manchester with one single substation (Falkirk Grove Wigan) suffering thefts on 27 occasions.

By working closely with Mandy Ingham (Network Strategy) Electricity North West Limited, ENWL have seen reductions of 78.9% (month comparison April 2011 – April 2013)



GREATER MANCHESTER
POLICE

Greater Manchester Police are grateful for the work of Mandy Ingham and her team at ENWL and for their efforts to reduce metal theft and improve the security of their assets as part of Operation Alloy and other initiatives

Some examples of where their support has been most valuable are:

1. **Days of action**
   ENWL have provided staff to support joint scrap yard visits to identify stolen metal

2. **Witness statements**
   ENWL have worked with Operation Alloy and the Crown Prosecution Service to develop and produce witness statements following theft incidents. These statements have helped in securing sentences that act as a deterrent in the future

3. **Providing materials for 'stings'**
   ENWL have when asked, provided cable and copper work which has been used in various operations

4. **Supporting additional resources for covert actions**
   Where ENWL have instigated covert operations they have provided financial support for the additional staffing to support these operations

5. **Trialling new techniques for security and marking of assets**
   ENWL have been open to new ideas and innovative in developing new techniques to protect and mark their assets

6. **Changing their scrap contract strategy to out of area disposal**
   ENWL have taken our advice on board when appointing their new scrap contractor who is out of the area which means there should be no ENWL scrap metal in local scrap yards

On the basis of the above examples, Greater Manchester Police believe that Mandy Ingham and her team at ENWL are commited to dealing with metal theft and security of their assets which has in the long term benefitted the people of the North West and will continue to do so.

Chief Inspector Rachel Buckle
Operations Lead TNS
Specialist Protective Services

Operation Alloy
Hardy Street, Eccles, Manchester, M30 7NB
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KELVATEK

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Gareth Evans

Head of Profession, Engineering

Ofgem

9 Millbank

London

SW1P 3GE

27th March 2013

Dear Gareth,

I am aware that the DNOs are currently preparing their RIIO-ED1 Well Justified Business Plans. I am writing to endorse ENWL as an innovative business and also commend them for their approach towards design and support of SMEs.

Since Kelvatek's inception at the end of 2008, the company has grown to having approximately 200 employees with over 100 engineers. The focus of the business has been on creating new and innovative products which can be used across the UK distribution system. Our philosophy is one of trying to solve 'key problems' but this puts a heavy reliance on our customers and their subsequent technical feedback during the various stages of the design process.

We have worked on several projects together with ENWL over the last few years and have always found them to be exceptionally receptive towards new ideas and concepts. Moreover, many of our existing products would not exist had it not been for the open and collaborative approach taken by the ENWL leadership, especially Steve Johnson, Mike Kay and Steve Cox. For Kelvatek, a UK SME, it has been invaluable to have had the consistent support of a DNO. For example, the Bidoyng Smart Fuse, which is now being deployed across the UK, was first conceived and created with ENWL, using the IFI initiative. The new SELF fault location technology and the Modular Rezap were also supported in the same way. These technologies are now being widely used by the other DNOs. We are currently involved in a number of new developments with ENWL which will produce a range of new products over the coming months.

The IFI, Tier 1 and Tier 2 programmes have been a great success in terms of stimulating investment into the UK electricity sector. This will continue with the NIA and NIC initiatives and Ofgem should be commended for their vision in creating them. However, in order to truly be successful DNOs need to have the correct approach towards new developments. We believe that ENWL sets a very good example of how to work inclusively with a wide range of partners, across a plethora of different projects.

It is our firm belief that the UK customers have ultimately benefited from our business being able to dedicate an unusually large percentage of our engineering resource towards designing products for the UK electricity sector. Without the continuous support of ENWL, at all levels of the organisation, we at Kelvatek would have been forced to take a much more restricted view of product development for the UK market.

In summary, risk management is a very important factor in making the choices of where to invest a company's finite resources. It makes the decisions more straightforward whenever we are able to work with partner companies like ENWL. The relationship has allowed us to foster a very creative and innovative environment which ultimately can only produce positive results for the UK consumer, both in terms of network performance and efficiency.

Yours sincerely,

Peter Cunningham

Managing Director

Ebrahim Hajat
Electricity North West
Hartington Road
Preston
PR1 8LE

Re: Electricity North West Key Performance Indicator

To whom this may concern.

ABB would like to endorse Electricity North West as a forward thinking, progressive and innovative organisation. Their promotion and dedication towards the ENA Assessment of our retrofit circuit breaker offering; which in itself is an innovative, trend setting product, shows their understanding of how the distribution network market is changing and evolving.

The fact that they are one of the first DNO's within the United Kingdom to actively identify, outline and now deliver the need for a change from the norm shows how progressive they are.

Yours sincerely,

Tom Cork

Medium Voltage Service Sales Manager

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Chiltern Power

Statement of Endorsement

The Innovation Approach of Electricity North West Ltd

I have worked with ENWL on matters concerning innovation over some ten years in a number of contexts. Most recently this has been in my role as an independent consultant and I have no hesitation in providing a statement of endorsement for their capabilities for innovation and their commitment to effective outcomes.

As an organisation they have been consistent contributors to promoting best practices in power network engineering over many years, and have demonstrated their willingness to contribute to innovation at a national level as well as for their company and its consumers.

Examples that support these observations are as follows:

- Unstinting support for industry technical committees over many years
- A wide innovation agenda: from Asset Management to Low Carbon solutions
- Leadership roles for innovation under the ENA, IET and Smart Grid Forum
- Formative contributors to Ofgem's early thinking for IFI and RPZ incentives
- Early adopters under IFI and effective partners with innovative SME vendors
- An imaginative project portfolio under the Low Carbon Networks Fund
- Developers and adopters of innovative network techniques at both HV and LV
- Bringing forward new staff to broaden the company's skills base for innovation
- Selectively working with partners and specialists to complement in house skills

The above examples demonstrate an enduring commitment to innovation that stretches over many years; my dealings with the company have consistently encountered not only a constructive and imaginative approach to fresh thinking, but also a foundation that is set upon seeking cost-effective and robust outcomes that will bring benefit to the company and its customers, now and for the future.

J G P Scott

John Scott, Director
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Company Registration Number: 7507096
VAT Number: 105 6110 64

Letter of Endorsement

The Approach to Innovation within Electricity North West Limited

EA Technology are happy to endorse ENWL for their committed and effective approach to innovation.

EA Technology have worked closely with Electricity North West Limited (ENWL) and its predecessor companies on a number of innovative projects since privatisation.

Throughout this time they have been closely involved in driving innovation, both in their own right and in partnership with other Distribution Network Operators nationally. In all cases ENWL have demonstrated their commitment to develop and implement solutions which benefit the company, their consumers and the industry as a whole.

Some examples of innovative projects where EA Technology have worked with ENWL are provided below:

1. **Early implementation of Condition Based Risk Management (CBRM).**
   ENWL worked with EA Technology to develop and implement CBRM models for all asset classes and used the models in their regulatory submissions.

2. **Development of new CBRM capabilities.**
   ENWL have continued to work with EA Technology to develop the capabilities of their CBRM models, most recently in the development of the risk process to provide the capability to produce Criticality Index outputs for the assets.

3. **Condition assessment of major cable assets**.
   ENWL worked with EA Technology to determine the options for condition assessment of their major cable assets and to develop an assessment process that would allow the asset condition to be understood and to feed into the CBRM methodology.

4. **Membership of the Strategic Technology Programme.**
   ENWL participate in all aspects of the programme managed by EA Technology and led by member companies to provide targeted and cost-effective solutions to improve network operation and efficiency.

These are a selection of the many projects in which ENWL have worked with EA Technology. The projects have been selected to demonstrate ENWL's consistent commitment to innovation and their implementation of the outputs of these projects.

On the basis of the above examples, EA Technology believe that ENWL are consistently driving innovation to the benefit of the electricity industry, the company and their customers.

Robert Davis

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Impact Research Ltd.
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United Kingdom

28th March, 2013

REF: LOW CARBONS NETWORK FUND – ELECTRICITY NORTH WEST LIMITED - CAPACITY TO CUSTOMERS

TO WHOM IT MAY CONCERN

Working with Electricity North West Limited (ENWL) has been overall a rewarding experience for Impact Research. ENWL's innovative and forward thinking approach has driven Impact Research to likewise propose creative solutions to gain insight into the likely success of initiatives proposed.

Within the scope of market research, ENWL's innovative programme has developed the skills to meet the UK's low carbon challenge, and this is shown by

1. ENWL's achievement in approaching this programme through a mix of systematic approach along with creative and imaginative thinking to the challenges faced in gaining customer feedback
2. The use of innovative techniques in market research. In our experience as providers of market research services, we have really appreciated the team working approach in which we have developed suitable techniques to measure the impact on customers of new ideas. This has combined qualitative research to explore how to best communicate the concepts, and the quantitative element to validate it's potential. Some of the techniques used in gaining this insight are some of the most innovative and effective techniques in market research.
3. ENWL's partnership approach. Their open approach to working with Impact Research is also behind the success of this programme. We have attended various meetings, conferences and forums, on many occasions beyond the immediate scope of market research to gain a broader understanding of the programme. These 'knowledge sharing' meetings have enhanced our understanding of the objectives and the importance of our role in achieving the aims of ENWL.

All in all, we at Impact Research believe ENWL are contributing significantly to coming up with ideas to meet the UK's low carbon challenge, through their creative and innovative approach and we are proud of being a part of this.

Yours faithfully,

Darryl Swift
Managing Director

FOREST OF BOWLAND
Area of Outstanding Natural Beauty

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elliott.lorimer@lancashire.gov.uk
www.forestofbowland.com

Mr Ian McCormack
Asset Investment Engineer
Electricity North West Ltd.
Hartington Road
Preston
PR1 8PP

Tuesday 23rd April 2013

Undergrounding for Visual Amenity in the Forest of Bowland Area of Outstanding Natural Beauty

The Forest of Bowland AONB Partnership has worked closely with Electricity North West Limited (ENWL) throughout DPCR4 and DPCR5 to help deliver the Undergrounding for Visual Amenity (UVA) programme within the area.

Throughout this time, the Partnership has found the company to be helpful, proactive and innovative in finding solutions to develop and deliver UVA schemes, which help the Partnership meet its statutory duty of 'conserving and enhancing the natural beauty' of the AONB.

The Partnership is keen for this excellent working relationship to continue as the company moves towards delivering more UVA Schemes under RIIO-ED1 from 2015 onwards.

Yours sincerely

Elliott Lorimer
Principal AONB Officer
Forest of Bowland AONB

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Web: www.peakdistrict.gov.uk
Minicom: 01629 816319
Aldern House . Baslow Road . Bakewell . Derbyshire . DE45 1AE

PEAK DISTRICT
NATIONAL PARK AUTHORITY

Your ref:
Our ref: MSB / A94241
Date: 30 April 2013

Ian McCormack
Asset Investment Engineer
Electricity North West
Hartington Road
Preston
Lancs
PR1 8PP

Dear Ian

Re Undergrounding for Visual Amenity Programme in National Parks and AONBs

I am writing to applaud the excellent work your company is doing in order to fulfill the expectations of the UVA scheme within the area of the Peak District National Park for which Electricity North West is responsible, as the principle DNO.

I have been impressed throughout the past 7 years or so by the efficient and consistent way in which stakeholders have been consulted and informed about progress of the DPCR5 undergrounding programme. I particular, I welcome the regular meetings held at Preston with all stakeholders and the enthusiasm shown by ENWL engineers and other staff involved in implementing the planned programme in each National Park and AONB involved.

As one of the country's leading National Parks, we welcome the commitment shown to the Ofgem allowance for undergrounding through the UVA scheme and the proposed 18% budget increase for the RIIO ED-1 spending period, which should enable some larger projects to be undertaken. We also welcome the publicity strategy proposed by ENWL to ensure maximum public awareness of the value of each project alongside your partner National Parks and AONBs. This has been recommended to the other DNOs involved in the Peak District.

Thank you for the opportunity to express our appreciation of the effective working relationship with which we have been involved over the past seven or more years.

Yours sincerely

Martin Burfoot

Martin Burfoot
(Landscape Architect and UVA Project Officer)

:\Documents and Settings\msb\Local Settings\Temporary Internet Files\Content.MSO\UVA letter re ENWL to Ofgem.docx/30/04/13 12:48/BM

Rosie Cooper MP

Labour MP for West Lancashire
House of Commons
London SW1A 0AA
020 7219 3000

RECEIVED
12 NOV 2012

08 November 2012

RC/AM/COOP01013/01121760

Mr Steve Johnson, Chief Executive Officer
Electricity North West Limited
304 Bridgewater Place
Birchwood Park
Warrington
Cheshire
WA3 6XG

Many thanks
Eddie
Steve

Dear Mr Johnson,

You may be aware that on Friday 19th October, I held a Flooding Forum with a number of key local agencies to discuss the handling of recent adverse weather in West Lancashire.

I am writing to thank you for the involvement of Eddie Hamilton in a productive meeting and for your company's continued hard work and support in relation to the issues that we face.

As I said at the meeting, we cannot stop the rain. What we must ensure however is that everything possible is done to protect West Lancashire residents' homes and local businesses.

Residents feel that there was a lack of co-ordination and responsibility taken by those who they believe should be dealing with problems caused by local flooding more effectively. In the wake of the response, I called the Flooding Forum meeting in order to raise the concerns of local residents and businesses, as well as pushing for greater cooperation so that we work together to minimise any damage caused by adverse weather in the future.

The forum will not be the last one, despite the progress, we still have work to do to minimise the risk of flood damage in West Lancashire from what is becoming more frequent 'extraordinary weather'.

I will continue to stand up for local residents on this matter to ensure that the people of West Lancashire have support in place, not only to assist them in the short term but also to reduce the long term threat of flooding to their homes and businesses. I hope that we will continue to work together on this important issue.

Yours sincerely

Rosie Cooper

ROSIE COOPER MP
WEST LANCASHIRE

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Solway Coast
Area of Outstanding Natural Beauty

Thursday 11th April 2013

Electricity Northwest
Hartington Road
Preston
PR1 8PP

Open letter of Support

Since the establishment of the Undergrounding for Visual Amenity project initiated by Friends of the Lake District (Fold) and subsequently adopted by ofgem the Solway Coast AONB has worked closely with Electricity Northwest and the Partnership of landscape protection organisations created.

Over the past 6 years we have witnessed the provision of 3440m of undergrounding within our AONB and we look forward to further provision in the future. Whilst undergrounding is not cheap it is incredibly worthwhile and once completed reveals an uncluttered and open landscape denied to us for many years.

Our working relationship with Electricity Northwest has been extremely rewarding and we have been impressed by their professionalism and their willingness to do whatever it takes to successfully complete a project. Communications, advice, publicity and training have all been given freely and without prejudice to the protected landscapes staff and as such we are better equipped and better informed in our everyday work.

We hope that this initiative will continue to provide for our AONB and that government will maintain or enhance their much needed support to this worthy scheme.

Once again thank you for your support.

Yours sincerely

Rose Wolfe
Assistant AONB Manager

YORKSHIRE DALES
National Park Authority

Mr I McCormack
Electricity North West
Hartington Road
Preston
Lancashire, PR1 8PP

Your Ref
Our Ref TH/UVA

4th April 2013

Dear Ian,

Re: Endorsement of Electricity North West Ltd

I write further to your recent request to provide a letter of endorsement regarding ENW's coordination of the Undergrounding for Visual Amenity' programme. My overall impression is that ENW has conducted the programme very professionally, communicating effectively with stakeholders throughout the process, and securing high quality outcomes on the ground.

Proactivity

My involvement with the programme, and therefore my contact with ENW, began in 2011, when following a number of staff changes, I inherited responsibility for providing the Authority's stakeholder input. This came at a time where DPCR5 was already well underway, and the Authority's slow start in proposing undergrounding schemes meant there was a risk we might fail to take advantage of the available funding allocation.

ENW staff were proactive in getting the Authority involved, stressing the urgency of the situation. Furthermore, they provided a one-to-one briefing to explain the background to the scheme and the way in which the distribution network and its infrastructure were affected by undergrounding proposals. This was invaluable given that I was entirely new to the scheme, the industry as a whole, and needed to be brought up to speed quickly.

ENW staff discussed specific schemes openly and honestly, emphasising at all stages that the final say in how the money was spent rested with the stakeholder, but ensuring our decisions were fully informed by the technical constraints of each particular scheme. This assistance has enabled us to suggest a number of viable schemes, all of which are now being progressed, enabling us to commit all of our funding allocation for DPCR5.

ENW staff have made themselves readily available to discuss issues specific to particular schemes, and this has been backed up by quarterly meetings where all stakeholders and ENW staff convene to discuss the wider programme. These meetings are run efficiently, and provide an invaluable opportunity to discuss issues of common interest, and to update stakeholders on developments with the forthcoming RIIO programme.

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Chief Executive: David Butterworth

Solutions to problems

Undergrounding schemes in National Parks are often fraught with difficulty given the inherent environmental sensitivity of the areas. It is fair to say that the undergrounding schemes pursued in this National Park have proven to be among some of the most challenging across the whole programme. In particular, archaeological and ecological constraints have had to be identified and worked around to secure the visual improvements from undergrounding. This has demanded patience and persistence from ENW staff as projects sometimes become bogged down by particular constraints.

In one project on Malham Moor - a highly sensitive area of early prehistoric settlement - ENW worked with ourselves and the landowner (the National Trust) to identify an alternative route for the undergrounded cable that avoided the most important archaeology. This included accommodating an excavation project, carried out by Bradford University students, to identify the most sensitive areas of archaeological remains. This reduced costs (using a commercial archaeological contractor would have been prohibitively expensive), facilitated learning opportunities for degree level archaeologists and enhanced our overall understanding of prehistoric remains in the area.

A similar regard for ecological constraints has also been demonstrated with a scheme at Swarth Moor, which is designated as a SSSI with a recently discovered population of statutorily protected Great Crested Newts. ENW had full regard to the ecological issues in planning this scheme, employing advice from ecological consultants to help reassure Natural England that the necessary mitigation was in place to prevent harmful impacts.

I hope that the above provides some sort of overview of how much we value the assistance given by ENW in facilitating the delivery of undergrounding schemes in the National Park. Should you have any further queries please do not hesitate to contact me.

Yours sincerely

T. Harlan

Thomas Harland
Planning Policy Officer

The Institution of Engineering and Technology

Founded 1871 Incorporated by Royal Charter 1921

This is to certify that the IET has Accredited the following Professional Development Scheme

Engineering Training Scheme

Provided by: Electricity North West Ltd

Accredited from June 2012 to June 2015 at the following location (s):

UK Wide

IET Reference: 1956.12.PD

Witness our hand and seal at Westminster this day 4th of July 2012

President

Member of the Board of Trustees

Chief Executive and Secretary

ANNEX 2A: CBRM PRINCIPLES

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Condition-Based Risk Management of physical assets within the electrical power sector

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Keywords: electricity, network, investment, risk, CBRM

Abstract

Condition-based risk management (CBRM) is a methodology that brings together asset information, engineering knowledge and practical experience of assets to define and quantify current and future asset condition, performance and risk. CBRM provides a means to express and communicate engineering information for large numbers of assets in a form that enables asset managers to define and justify future investment. The CBRM methodology was first created by EA Technology Limited (EATL) and Electricity North West Limited (ENWL) in 2002/3. Over the past 10 years, both parties have continued to update and develop the process, using the outputs to support ENWL's asset management activities. This paper documents this evolution.

1 Introduction

The CBRM methodology and its application have been developed by EATL in conjunction with electricity network operators over the past 10 years. CBRM projects have been carried out with over 50 companies in at least 12 countries. It is important to emphasise that CBRM is a flexible methodology and not a rigid, fixed process. CBRM models have been built for the main asset groups (transformers, switchgear, cables, overhead lines, etc.) many times, but every model is different, reflecting the specific information available, the specific operating context and the particular requirements of the client. Each application is therefore a learning experience and almost without exception each application has resulted in some development and extension of CBRM capabilities.

Thus, it is true to say that CBRM has continually evolved over its 10 year history and every one of the 50 plus companies have contributed in some way to this evolution. However, the contribution of some of these companies has been particularly significant. In that context EATL is delighted to document and acknowledge the role played by ENWL, by means of this paper.

2 CBRM development timeline

The development history of the CBRM process is described below, covering the period from 2002 to date.

2002

ENWL was facing the twin challenge of managing an ageing network with a large peak of assets approaching nominal 'end-of-life' and an increasingly demanding regulatory environment. They recognised the need to move from age based asset models to condition and/or risk based models in order to renew the network in a cost effective manner and maintain levels of reliability.

2002/3

In response to these challenges, ENWL and EATL created the first generation CBRM models for 20 major asset groups [1]. These models defined current asset condition by a numeric health index (HI) for each asset. The HI was explicitly linked to the probability of failure (POF) of the asset. Current HIs could be aged to estimate future HIs and POF, enabling estimation of future failure rates with specific levels of intervention.

2004/5

The CBRM models were used to define and justify replacement volumes in the fourth Distribution Price Control Review (DPCR4) submissions to the electricity regulator (OFGEM). The use of the models resulted in reduced replacement volumes to maintain the current failure rates when compared with traditional age-based models. The results were positively received by OFGEM.

2005/6

Learning from the experience of building and populating the first-generation CBRM models, ENWL reviewed and modified the information gathered during inspection and maintenance processes to improve the reliability and discrimination of the HIs [2]. EATL, in conjunction with other electricity companies in the UK and overseas, further developed and improved the CBRM methodology.

2006/7

ENWL and EATL created and populated second-generation CBRM models. These included improved methodology and asset information, leading to improved HIs that enabled interventions to be applied with more confidence for individual assets.

During the development of these models with ENWL, the process was extended to include consequences of failure and asset criticality, enabling current and future 'asset risk' to be quantified for individual assets [3].

2009/2010

During the fifth Distribution Price Control Review (DPCR5), OFGEM adopted the concept of HIs as a reporting measure for distribution network operators [4]. At this time, OFGEM also adopted load indices to support load-related investment.

OFGEM also identified a future requirement for an output measure that reflected both probability of failure and asset criticality.

The ENWL capital expenditure requirements for asset replacement in their DPCR5 submission were supported by output from their improved CBRM models and were again well received by OFGEM, resulting in virtually all proposed replacement volumes being accepted.

Post-DPCR5, working towards RIIO

OFGEM is currently working to define more detailed reporting requirements under the new regulatory regime (RIIO: Revenue = Incentives + Innovation + Outputs). These outputs are being developed and implemented during DPCR5 and will include both HI and criticality index (CI). It is OFGEMs explicit intention to use these to demonstrate and quantify risk reduction for future investment plans [5].

In addition to being able to generate the required CIs, the risk process within CBRM provides the means to explicitly quantify the change in risk (expressed financially) for any investment package and enables investment to be targeted at assets with the optimum cost-benefit. With CBRM models it becomes possible to move to a genuine risk-based asset replacement strategy.

In addition to this, ENWL and EATL (in conjunction with other UK network operators) have undertaken work that builds on the concept of load indices and quantifies load-related risk. Significantly, this will enable the building of a risk methodology that combines load and condition risk, enabling the cost benefit of investment proposals across both streams to be directly compared.

This paper reflects ENWL's experience of CBRM but it is also important to note that during the period of CBRM development and application with ENWL, EATL has worked with many other electricity companies, as well as with gas network operators and operators of private networks. CBRM models have been built with over 50 companies in more than 12 countries, often to assist with development and support of investment plans for regulatory submissions. It is important to recognise that the all these projects and all the companies involved have contributed to the overall development and the capability of the CBRM process. However, as this paper highlights, ENWL's involvement in the development of CBRM has been crucial. The first CBRM models were created with ENWL and a number of subsequent key developments have been undertaken with them. Their original challenge to produce an analytical process based on asset condition, their hard work and persistence in moulding the outputs to meet their requirements and their involvement in ongoing improvement of the process has made a major contribution to its overall development and application worldwide.

3 CBRM outputs

The fundamental outputs for each asset are as follows:

- The health index (HI)
- Probability of failure (POF)
- Risk - expressed in monetary terms (£s, $s or €s)

For each group of assets, the following are also produced:

- Health index profiles – overall distribution of health indices
- Overall failure rates
- Total risk

Crucially, the model enables the current health index to be 'aged' so that future, condition, performance (failures or failure rates) and risk can be estimated with and without interventions. The process is highly granular and it is possible to factor in any combination of interventions.

Quantifying risk

The risk calculation is based on combining the POF value obtained from the health index with the consequences of failure. The consequences of failure are defined in several categories, typically network performance, safety, financial and environmental.

In each category the average consequences are estimated (based where possible on recent failures). In each of the categories the consequences have their own specific units (e.g. customer-minutes lost and customer interruptions for network performance, fatalities and injuries for safety, £s, $s or €s for financial and litres of oil, kg of SF_6, etc. for environmental).

Each of these consequences is given a monetary value. The overall risk is therefore calculated in financial terms. The relative importance of individual assets can be accounted for by defining the 'criticality' of the asset separately in each of the categories.

The significance of risk in investment planning

The significance of risk in asset management decision making terms is twofold. Firstly, it provides the opportunity to consider the criticality of individual assets. The asset in worst condition, with the highest POF, may not be the asset which poses the largest risk; that may be a more critical asset in better condition. Secondly, and more importantly, quantifying risk enables comparisons to be made across asset groups.

Because the measure of risk is the same for all assets, the benefit (the reduction in risk) for any intervention involving any combination of different assets can be compared.

Therefore risk quantification potentially offers asset managers an invaluable planning tool, the ability to be able to rank all investment projects on the basis of cost/benefit and perhaps the ultimate ability to define the financially optimum risk profile and future investment plan. The potential power of this is illustrated further in the following section and case study.

Financial optimisation

By quantifying risk in financial terms, CBRM provides the possibility of financial optimisation of investment [6].

Using a simple Net Present Value (NPV) model, the cost of investment which in present-value terms decreases if the investment is delayed, can be balanced against the increasing risk if an asset in poor condition, with an increasing POF and risk, is left on the network. The determination of the optimum i.e. 'least-cost' point to invest is illustrated in Figure 1.

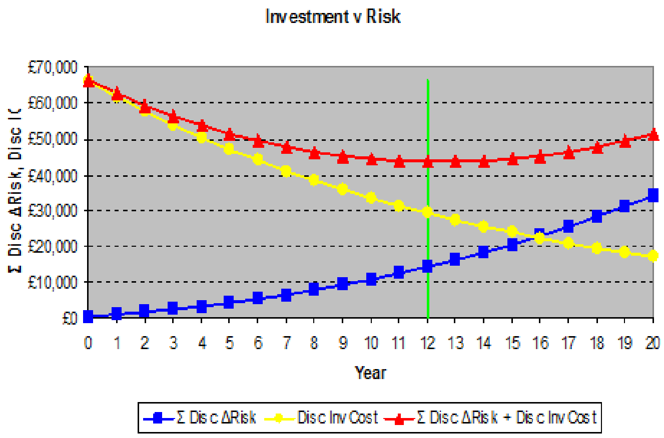

Figure 1: The NPV/risk curves for an individual asset, defining the optimum replacement year

For any asset the optimum replacement time (the time at which the sum of the investment cost and risk is at a minimum) can be calculated, and this can be used to generate an optimal 'least-cost' investment programme, as illustrated in Figure 2.

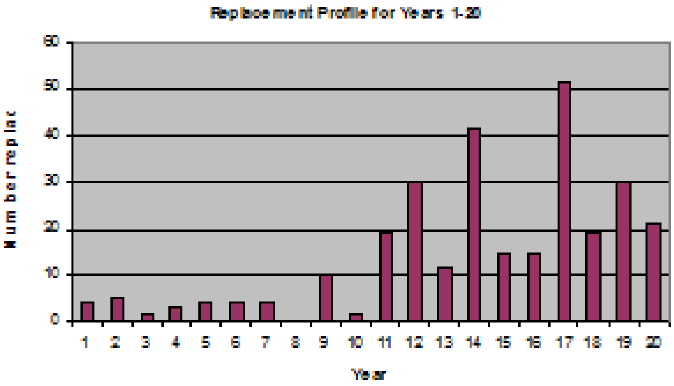

Figure 2: The optimum replacement profile for an asset group, derived from NPV/risk curves for individual assets

This process provides a means to efficiently define the optimum replacement programme (i.e. the most cost-effective programme) across all asset groups.

4 Implementation platform considerations

Initially, CBRM models were built as standalone spreadsheets. The flexibility and transparency of spreadsheets proved ideal for collating data from lots of disparate sources and building bespoke models via a series of interactive workshops. With the aid of the EATL software team, we were able to construct complex models with a high degree of functionality that were successfully deployed with many companies.

The models then progressed from one-off snapshots - produced to deliver outputs for a specific purpose, usually a price review submission - to ongoing asset management tools that required periodic updating. It then became apparent that spreadsheets were not the ideal vehicle for future delivery.

Consequently, EATL developed a software-driven database tool (CBRM 2.0) to deliver CBRM models. This has become the favoured delivery vehicle (although for trial applications or applications with smaller companies, spreadsheet models remain an appropriate solution). The concern when moving to the new system was that we would lose the flexibility and transparency that is such an important element of CBRM. The EATL software team have succeeded in creating a system that retains a high level of flexibility and transparency, and so maintains the essential character of the process.
CBRM 2.0 is sometimes described as an integrated solution, meaning that it is integrated with the IT systems of the client company so that the models can be automatically refreshed/updated directly from the client IT systems. While this level of integration has been achieved in at least one case, in reality most applications to date would better be described as partially integrated. In most cases, the client companies do not have all the necessary input information in systems that can be interfaced in this way. In the majority of cases it is necessary to create an intermediate data repository to which information from a variety of sources can be transferred, audited and then uploaded.

This flexibility in gathering source data has proved to be an important feature of successful implementation and is an effective means of establishing a system that can be refreshed periodically in a reliable and efficient manner. CBRM 2.0 has therefore been demonstrated to be an effective and robust asset management system suitable for providing output to support decision making in an ongoing, routine manner.

5 Why CBRM works for ENWL

ENWL have identified a number of reasons why the CBRM methodology is particularly appropriate for their investment planning:

1. CBRM is a process that is based on capturing, utilising and reflecting asset information, engineering knowledge and practical experience of the assets to influence and justify investment plans. Specific engineering knowledge and experience of the assets must be a better basis for making asset management decisions than high level models that do not reflect specific knowledge of the assets.
2. CBRM is a transparent process. It is straight forward to relate an output (a HI or risk value for a specific asset) to the information that gave rise to it. It brings together all relevant engineering information for each asset and thus provides clarity of reasons for replacement or other intervention.
3. The data is cost-effective to collect and maintain. This minimises operational expenditure while enabling ENWL to meet their statutory requirements.
4. CBRM is a tool to provide asset managers with information to assist with decision making; it is not a process that tells you what or how to intervene on an asset.
5. It provides a view of the future performance (failure rates or risk) for different investment scenarios and thus assists ENWL in working collaboratively with OFGEM.
6. It provides a means of testing the cost effectiveness of different investment plans by comparing cost with outcomes.
7. For high volume asset groups (distribution) it provides a structured methodology to define asset replacement volumes linked to measurable outputs.
8. For lower volume (higher value assets) it provides a structured process, for assessing the benefit and cost effectiveness of specific interventions (replacement or different levels of refurbishment) for individual assets.
9. The CBRM models have been instrumental in achieving satisfactory outcomes from the two most recent price reviews
10. The output from CBRM models provides an excellent basis for meeting the current and future reporting requirements of OFGEM.

6 Summary of CBRM in 2012

The CBRM methodology has undergone considerable development and evolution in the last ten years. Nevertheless, some aspects of the process have emerged as essential to ensuring a successful deployment. These are described below, and in the authors' view should be seen as the key 'success factors' when considering the deployment of similar investment planning processes.

CBRM is a bottom-up, asset-specific process. It collates information for individual assets and uses this to define condition, performance and risk of individual assets currently and with any future investment programme. This means that interventions can be applied - and the effects assessed - at the asset level. Detailed asset-specific interventions can then be evaluated.

Its primary purpose is to bring together, summarise and communicate all available and relevant asset information, engineering knowledge and practical experience of the assets to enable this information, knowledge and experience to be accessible to influence investment planning.

It is a flexible methodology, not a rigid prescriptive process. From the outset it was realised (i) that to be relevant it was necessary to be able to use whatever information was available (not to define a specific set of information points for a particular asset) and (ii), to produce results that were credible we had to capture, apply and reflect the engineering knowledge and experience of the local engineers and asset managers.

CBRM was originally created in response to specific requests from network operators and development has continued to follow this approach. Most developments have been undertaken while working with network operators. Consequently, the methodology, its application and outputs have been carefully tailored to the particular needs of network operators.

CBRM models are transparent. They are not 'black boxes'. On completion of a project engineers and asset managers should have a complete understanding of the input information and how it is combined to arrive at a particular result. They should understand the calibration mechanisms built into model and know how to adjust them to reflect their knowledge and experience. It is easy to trace back from a result (a HI or risk value for a particular asset) to the information that has given rise to it.

Creating and populating CBRM models is an inclusive process. We seek to involve a good cross section of engineers and asset managers with practical knowledge of the assets in the process. Our aim is for them to take ownership of the models and overall process.

The process provides genuine analytical capability. The definition of condition by deriving a numeric HI is by itself a descriptive outcome. However, by linking the HI to POF and then combining the POF value with consequence and criticality information that ultimately results in a risk value expressed in monetary terms, it becomes possible to produce output in the form of failure rates and/or changes in risk expressed in monetary terms for different future investment programmes.

CBRM is a process that promotes and benefits from continuous improvement. Initial models are built for and populated with available information, producing the best definitions of condition etc. with that information. This initial experience then provides a platform for improving the asset information so that subsequent iterations of the models can utilise better information and incorporate developments to the methodology.

One of the primary uses of CBRM models is to assist network operators prepare and justify reports and price review submissions to regulators. In general regulators have reacted positively to the methodology and the outputs produced. In some cases it is apparent that the application of CBRM has made a significant and positive contribution to the direction of regulation and expectation of regulators.

7 Conclusions

The condition and risk based methodologies developed as part of CBRM have demonstrated the potential for asset based risk models that utilise available asset data and the extensive engineering knowledge and practical experience that exists within electricity companies.

The asset information, the extensive engineering knowledge and the practical experience relating to the performance of these assets represent a very significant resource for network operators. Use and communication of this should be a vital component in achieving cost effective investment programmes to maintain acceptable levels of reliability.

The approach embodied in CBRM, combined with the ability to produced measured outputs for different investment strategies, is generally positively received by regulators. Hence CBRM models are playing an increasingly significant role in presenting and justifying future plans for many companies in several countries.

The industry continues to face up to the increasingly demanding challenges of renewing ageing networks, maintaining or improving levels of reliability, introducing smart grids and low carbon networks while demonstrating efficiency and effectiveness to satisfy regulators and operating in a business environment where access to capital can be difficult. It is therefore believed that such models will become increasingly important.

Acknowledgements

EA Technology Limited would like to thank Electricity North-West Limited for their considerable and ongoing contribution to the development of CBRM methodology. I would also like to thank Bob Wells personally for his valuable assistance in preparing this paper.

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ANNEX 2B: CBRM - DETAILS

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Contents

1. Executive Summary

As detailed in section 3 of our business plan, we have led the industry in the development of Condition-Based Risk Management (CBRM) approaches over the last ten years, and the subsequent development of Health Indices in DPCR5. Health Indices allow an overall view of an asset's health to be formed from all available information and Annex 2 to the plan gives more details on the evolution of the CBRM approach.

This document details the development of Health indices into an overall risk framework, and sets out the resulting RIIO-ED1 projections for each major asset type.

2. Development of Health Indices

In CBRM, health scores are calibrated to the expected probability of failure of an asset in a specific state. As an asset ages, its probability of failure does not increase at a steady (linear) rate. The trends are specific to each asset type but generally stay constant for a significant proportion of the asset's life before starting to increase significantly as the asset approaches the end of its life. This is often referred to as the 'bathtub curve' effect and is modelled in CBRM using cubic or exponential functions. For reporting purposes, these scores are reported against a simple 1-5 scale.

There is an underlying probability of failure for all assets due to incidents such as third party damage (even the newest assets can fail, albeit infrequently) and this risk is also included in the CBRM models.

The resulting probabilities of failure (in terms of the likelihood of an asset in that state failing in any one year where 1 = certainty) corresponding to each Health Index state for each asset type are as follows;

Health Index	**HI1**	**HI2**	**HI3**	**HI4**	**HI5**
	Probability of annual failure				
LV Switchgear and Other	0.001	0.002	0.003	0.004	0.013
LV UGB	0.001	0.001	0.001	0.003	0.006
LV OHL Support	0.002	0.002	0.004	0.008	0.013
HV Switchgear (GM) - Primary	0.000	0.001	0.002	0.003	0.006
HV Switchgear (GM) - Distribution	0.001	0.001	0.001	0.003	0.005
HV Transformer (GM)	0.001	0.001	0.002	0.004	0.012
HV OHL Support	0.002	0.002	0.004	0.008	0.012
EHV Switchgear (GM)	0.000	0.001	0.002	0.003	0.006
EHV Transformer	0.001	0.001	0.002	0.004	0.008
EHV UG Cable (Gas)	0.001	0.001	0.003	0.007	0.010
EHV UG Cable (Oil)	0.001	0.001	0.003	0.007	0.010
EHV OHL Support - Towers	0.000	0.000	0.000	0.000	0.001
EHV OHL Support - Poles	0.001	0.001	0.001	0.003	0.004
EHV OHL Fittings and Conductors	0.000	0.000	0.001	0.004	0.010
132kV CBs	0.002	0.002	0.004	0.007	0.013
132kV Transformer	0.002	0.002	0.004	0.008	0.017
132kV UG Cable (Oil)	0.001	0.001	0.003	0.007	0.010
132kV OHL Support - Tower	0.000	0.000	0.000	0.000	0.001

132kV OHL Fittings and Conductors	0.000	0.000	0.001	0.002	0.007

These values have been used in our Risk model and translated into the new CM105 table in the re-submission template.

3. Consideration of Consequences

To develop a full risk model, consideration also has been given to the consequences of the failure of an asset. The combination of the probability of a failure occurring and the consequences of the failure generates an overall failure risk score for an individual asset. These scores can be summated to generate an overall position for the whole asset population which is being measured.

3.1 Measurement

To measure the consequences of an asset failure, it is important to take into account all its potential impacts. It is also important that the same factors are taken into account for all asset types to give the potential for comparisons of risk between asset types. Measurement of the consequences of failure in the Risk model uses the following factors agreed with Ofgem;

Category	Factors considered	Calibration
Safety	Potential impact on safety incidents	£ Published Cost of Life data x probabilities of incident
Environment	Carbon emissions, oil leakage	£ Cost of Carbon (Green Book value), also cost of oil loss
Customer Performance	Loss of supply	£ Value of Lost Load or £ IIS incentive rates
Repair costs	Costs	£ NPV

These represent the potential impacts of asset failure and each is quantified in pounds to give an approximation of the actual financial impact of the failure of an asset.

We have used our historic experience of asset failures, together with wider industry knowledge and third party expertise to apply these factors to our assets and produce the following average consequence of failure values which are also shown in table HI8 of the re-submission.

Asset Type	Average consequence of Failure (£)
LV Switchgear and Other	10,169
LV UGB	11,140
LV OHL Support	7,778
HV Switchgear (GM) - Primary	121,085
HV Switchgear (GM) - Distribution	32,450
HV Transformer (GM)	20,961
HV OHL Support	17,378
EHV Switchgear (GM)	93,604
EHV Transformer	317,306
EHV UG Cable (Gas)	124,983
EHV UG Cable (Oil)	277,966
EHV OHL Support - Towers	428,896

EHV OHL Support - Poles	117,544
EHV OHL Fittings and Conductors	228,326
132kV CBs	824,797
132kV Transformer	858,587
132kV UG Cable (Oil)	127,407
132kV OHL Support - Tower	1,286,083
132kV OHL Fittings and Conductors	682,956

Some of the values for the more strategic assets may appear high. This is because failures, although extremely rare, have potentially high, even catastrophic impacts. We also have to consider that the network at EHV and 132kV levels is duplicated such that those failures that do occur rarely impact customers directly. If we look at the actual impacts of such failures historically, we take for granted the duplication of the network.

In order to ensure we credit it appropriately, we have to consider the potential impact of failures if the duplicate network wasn't there. To do this, we use a metric termed the 'Value of Lost Load' which values the potential economic impact of the loss of electricity supply. This approach mirrors that developed by Ofgem in RIIO-T1 where a similar approach was used.

3.2 Asset Criticality

In presenting our proposals for RIIO-ED1, we have allocated all assets within a population to one of four Criticality 'bands' to reflect the criticality of an individual asset's failure with respect to the average for the asset type. This is based on the assessed consequences of failure for that particular asset relative to the average for the asset type.

This allows us to take into account the fact that assets which are superficially similar and perform a similar function may have quite different consequences of failure due to their size, location, number of connected customers, type of construction, accessibility etc.

For the purposes of building the risk model, we use representative values for each band as detailed below;

Criticality Band	Minimum value	Maximum value	Used for model
1	0%	75%	70%
2	75%	125%	100%
3	125%	200%	150%
4	200%	>200%	250%

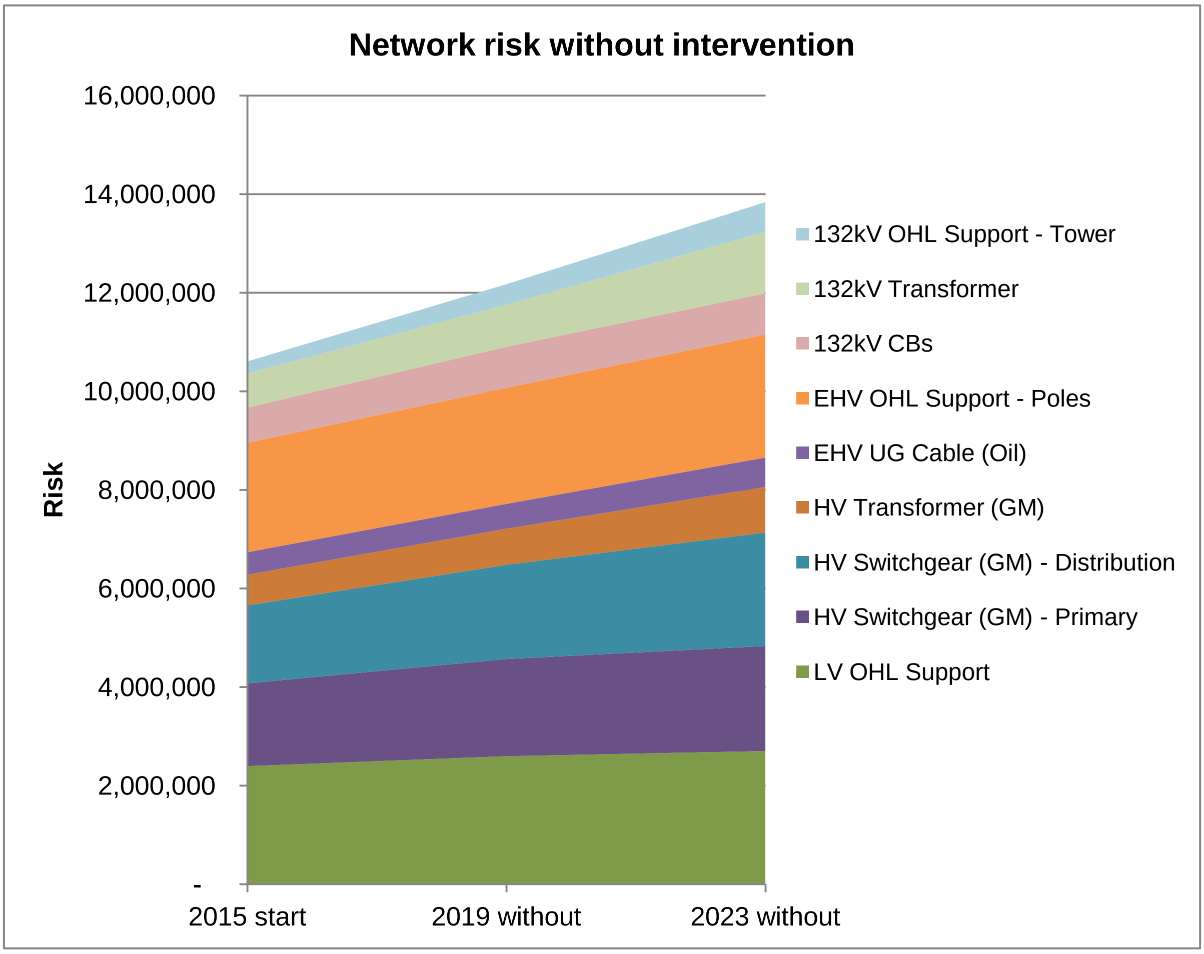
4. Modelling Deterioration

Having set the framework in place, it is important to establish a baseline for the comparison of investment options. This baseline represents the 'do nothing' option, ie what would the impact on risk be if we just left the current network alone (apart from routine inspection and maintenance activities), fixed faults as they occurred and saw what happened?

In general terms, the consequences of asset failure stay the same; however the probability increases – as assets age and deteriorate, their condition progressively worsens and hence their probability of failing increases. Using the risk model, we can predict what the likely impact on future failure rates would be for each asset type, and the consequent level of overall risk.

Using the framework outlined above, our forecast is that overall network risk will increase by 14% from its 2015 level by 2019 and by 29% by 2023 if we make no further proactive investment.

This can be seen, both in totality and by asset type using our consolidated risk framework;



5. Impact of Investment

Having established the ‘do nothing’ baseline, we can then overlay the impact of potential investment programmes using the same calibrated factors. Investment will potentially impact either the probability of an asset failing, or mitigate the consequences if it does fail.

In many cases, there are a number of potential options with different costs. It may, for example, be possible to achieve a small improvement in an asset’s health by refurbishing a small number of components. A more significant improvement could be achieved by a more expensive refurbishment of the complete asset and replacement of the entire asset would gain the greatest benefit, but at the highest cost.

Not all these options are available for all asset types; however where they do exist, it is important to ensure the appropriate trade-off is made to ensure we get the best value for money from our investment. To help us make these decisions, we use Cost Benefit Analysis (CBA) to evaluate different costs and benefits over a longer timeframe. In order to ensure consistency, our CBA models use exactly the same factors and calibration as our Risk model. Annex 3 details our approach to CBA in more detail and presents a specific CBA for each HI category. The options modelled are presented in terms of the Health and Criticality matrices used in tables HI2-8.

Increasing network risk is not necessarily a bad or inappropriate thing. There are three generic options for setting future risk levels;

- Decide on a preferred level of future risk and build an investment programme to achieve it
- Decide on the level of an input constraint (eg volume of work or amount of investment) and see what level of risk results, or
- Determine the lowest whole-life cost approach for managing the asset base and allow the level of risk to 'float' around this.

In line with our Asset management policy (see Annex 11), our approach is to assess the most efficient approach to those assets identified as requiring intervention (which ranges from 'do nothing' to full replacement) and collate those requirements into an integrated delivery plan. The overall level of network risk post-investment can then be forecast.

6. Overall Results

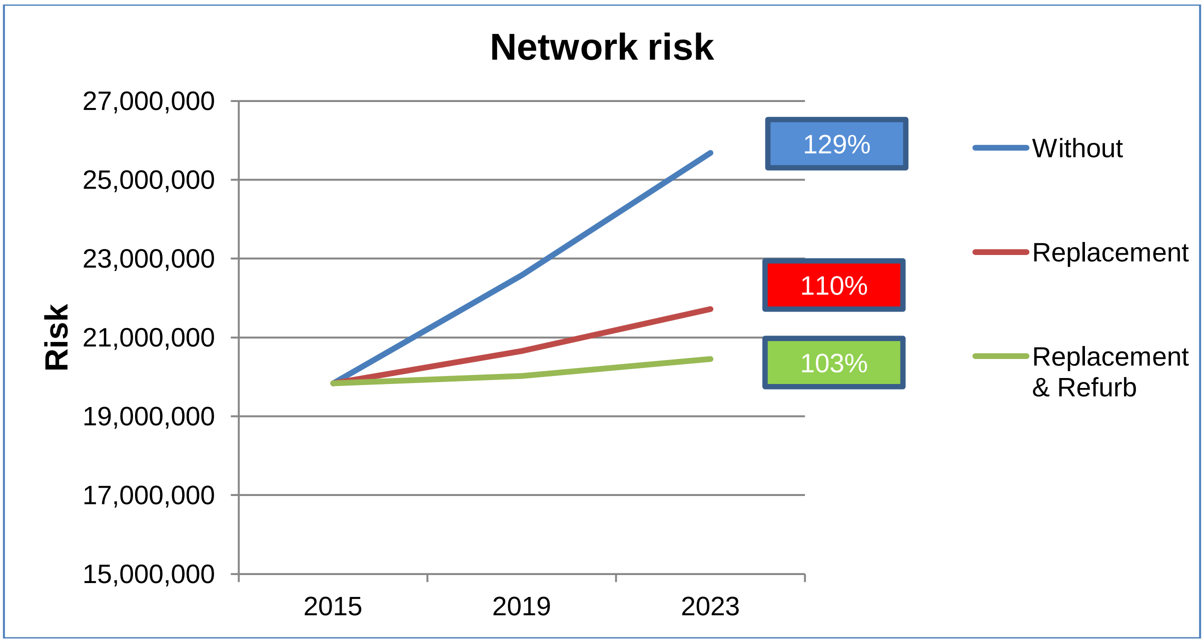
Using the risk framework allows us to see the impact of proposed investment programmes and calibrate the overall risk level.

As noted above, the forecast 'do nothing' position is forecast to see a 14% increase in network risk by 2019, rising to 29% by 2023.

Our proposed replacement programme mitigates this deterioration to 4% by 2019 and 10% by 2023.

In addition, our proposed refurbishment programmes will restrict the increase in risk further such that we are forecasting a risk position of 101% by 2019 and 103% by 2023 as a result of our planned programme.

We could have added further volumes to the programme to bring this risk to 100% of its 2015 level in 2023. Based on the average cost of risk reduction in the programme, we estimate that this would have cost an additional £42m which we consider would not represent good value to the customer. The resulting slight increase in the probability of future failure to 2023 is not likely to manifest itself in customer impacts given the increased investment in mitigating the impact of any faults that do occur through additional Quality of Supply improvements as detailed in the main narrative.



We will report on our progress on achieving this metric each year and commit to maintaining the overall level of network risk within 3% of its 2015 position during the RIIO-ED1 period.

7. Details by Asset Type

The following section sets out the results of the risk approach for each of the 19 asset categories for which projections have been included in the RIIO-ED1 forecasts. These projections can be found on tables HI2, 3 & 4 of the BPDT template pack.

In each case, the overall volumes of work and expenditure have been set alongside the resultant change in risk. There is a range of costs of risk reduction and we use these figures to check the calibration of the programme across the different assets types (such that we are not over-investing in an asset type with relatively high costs of risk reduction).

We have also included a comparison of the resulting intervention rates with those representing the industry medians used by Ofgem in their fast-track analysis for asset replacement.

Depending on the starting position of the asset population, the forecast deterioration and the proposed intervention plan, the risk at the end of the period can be lower, greater or broadly the same as the starting position. We have not artificially changed the programme to achieve pre-determined levels of risk by asset type.

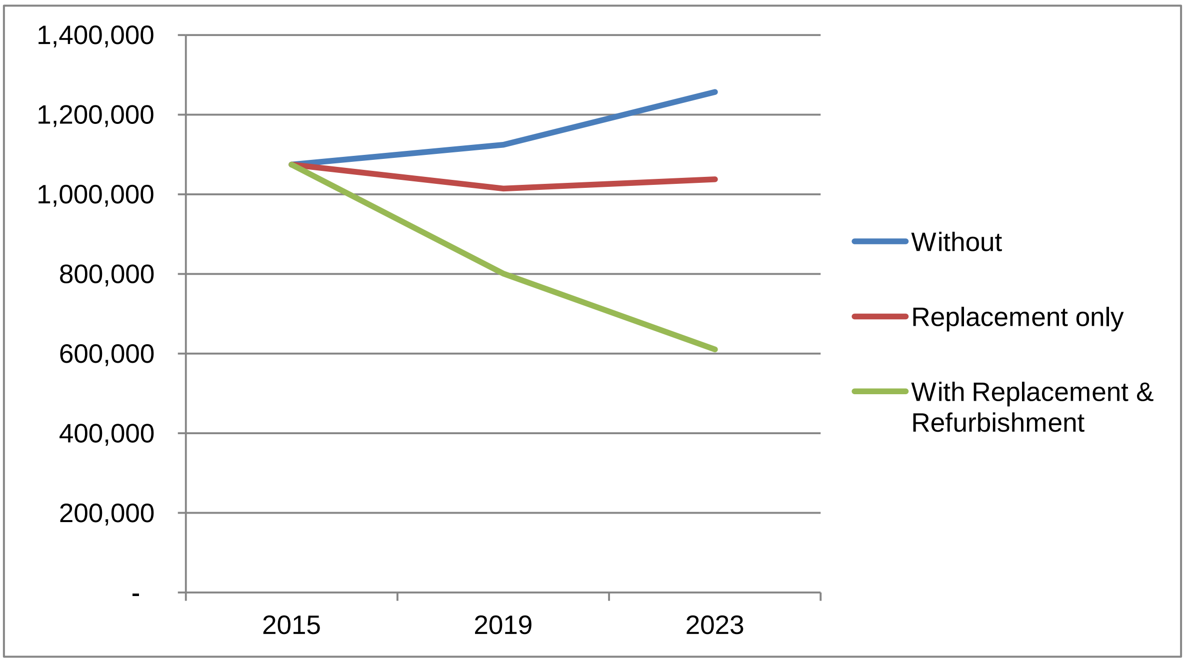
7.1 LV Switchgear and Other

These assets control the outgoing LV circuits from distribution substations.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	Asset register	DPCR5	RIIO-ED1	Planned	DNO median	DPCR5	RIIO-ED1
LV Pillar (ID)	3,728	198	560	15%	6%	1.0	4.4
LV Pillar (OD at Substation)	6,804	536	896	13%	15%	2.9	7.6
LV Board (WM)	6,083	144	400	7%	15%	1.5	6.5

CBRM modelling has been used to identify LV switchgear in poor condition with an expected end of life occurring prior to the end of RIIO ED-1. These condition-related replacements have been combined with those assets identified for intervention due to their specific operational issues and those consequential to other work to produce the forward programme whose impact is further explained below.

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
16,615	1,856	18.5	3,445	2.0	645,904	32

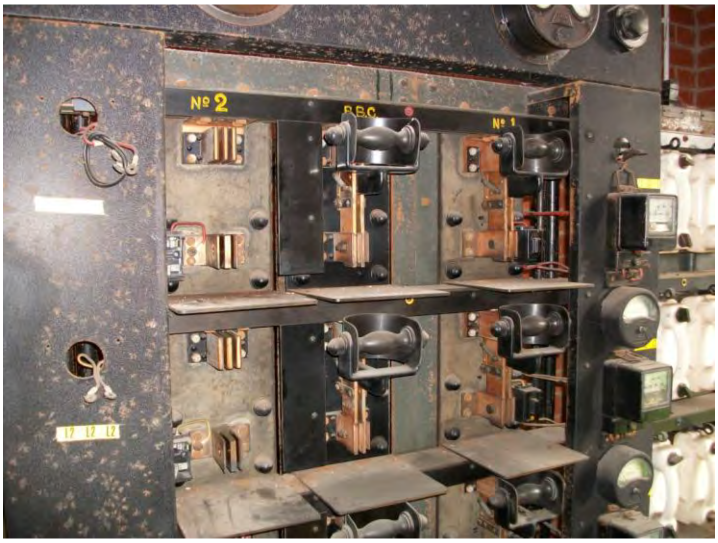


Our internal policy Code of Practice 352 (Guidance Note 4) describes the strategy to be applied in the management of LV switchgear at substations.

This strategy identifies intervention options for the various types of LV switchgear asset on the ENWL network. In addition to condition related interventions, it includes a strategy for those types or groups which present generic onerous operability conditions and where modern fault restoration equipment (eg Fusemates and Rezaps) cannot be accommodated delaying restoration time thus increasing CMLs. This is mainly prevalent for the Wall Mounted LV Boards identified in our RIIO-ED1 plan for replacement, the number of these assets leading to a higher than median intervention rate.
These types and groups include:

- Spring clip boards.
- Spring Contact Transformer Isolators.
- Boards, pillars and cabinets which do not have full interphase and phase-neutral barriers at fuse-ways and the incoming isolators.
- Manchester Boards.
- Other Norweb manufactured LV Fusegear.

Examples of some of these board types are shown below.



Spring Contact Transformer Isolators

Spring clip board

Manchester Board

The majority of the LV switchgear replacement volumes have been identified using the CBRM process and our internal policy which details the intervention strategy for specific LV plant types. This category is dominated by a particular type defect that has been identified with units manufactured by ABB and its predecessor companies post 1992.

ABB/Nitran/Bonar Long boards and cabinets with fragile test sockets pose a specific risk and a modification has been developed to replace these defective test sockets. This modification is suitable for around 90% of the affected LV boards and will remove the defect and enable continued safe operation. We issued a Suspension of Operational Practice (SOP 2012/0380/00) through the Energy Networks Association NEDERS system on 25 January 2012 describing the type defects with such equipment.

However, approximately 10% of the affected ABB Nitran/Bonar Long boards are anticipated as not being suitable for refurbishing due to several variants of the test socket arrangement that exist and have been included in the LV switchgear replacement numbers.

These make up approximately 39% of the LV Pillar (ID) volume and 18% of the LV Pillar (OD at Substation) volume contributing to the higher than median intervention rate.

Volumes associated with consequential outputs

In addition to those LV boards identified for replacement due to their condition or unsatisfactory operability characteristics, consideration has been made of the number of LV boards which will need to be replaced as a consequential output when carrying out transformer replacements.

Experience has shown that due to substation and plant assembly arrangements and the space available in the substation, it is not always practicable to replace distribution transformers in isolation. There is sometimes a need to replace the existing LV switchgear as well, even if its condition would not normally necessitate replacement. These replacements are only sanctioned when all other solutions have been explored eg re-mounting the existing LV cabinet to the new transformer.

Based on current experience we forecast that 25% of the distribution transformer changes will require the replacement of the LV switchgear as well. This has led to an anticipated volume of 277 consequential LV switchgear replacements being added with a circa 50/50 split to the LV Pillar (ID) and LV Pillar (OD at Substation). This additional replacement volume further contributes to a higher than median intervention rate.

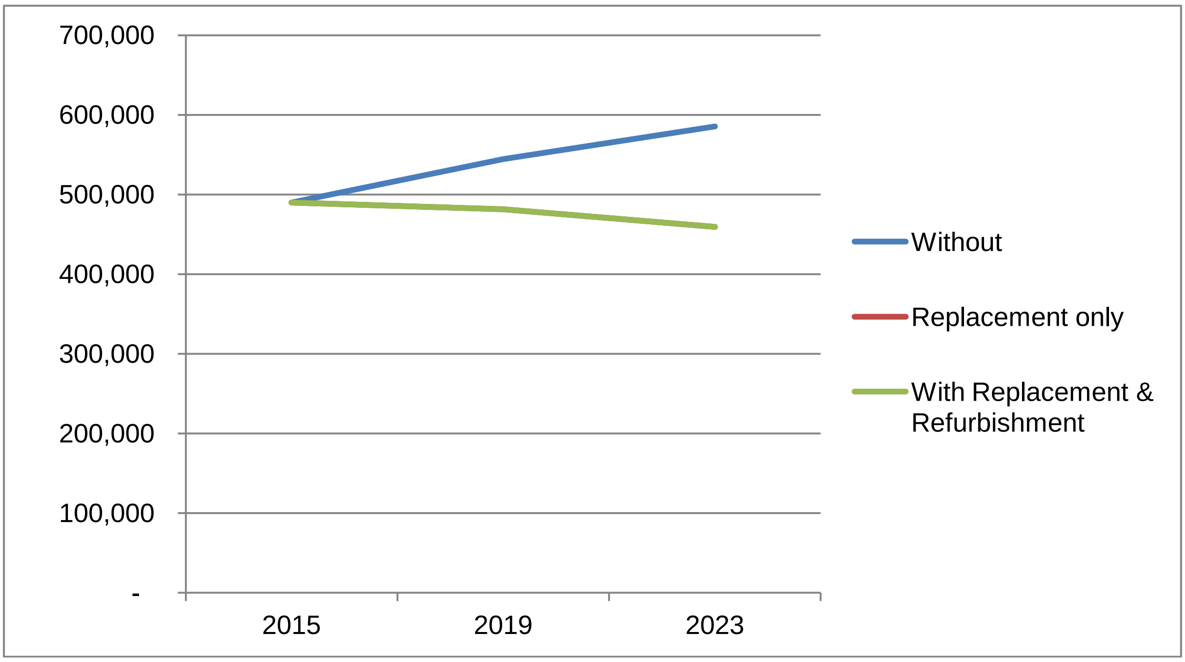
This investment forecast will result in a reduction of risk of 43% over the RIIO-ED1 period compared to the starting position due to the resolution of the ABB Board issue which is increasing the risk for this asset type above the level we would normally expect.

7.2 LV Link Boxes and Outdoor Pillars

This category covers underground link boxes and multiway pillars located outside of substations. These assets permit access to cable systems and hence are invaluable aids to operating the LV system.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
LV UGB & LV Pillars (OD not at Substation)	20,062	1,150	1,752	9%	9%	4.0	8.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
20,062	1,752	8.0	-	-	126,116	64



We have a considerable numbers of these assets which we have identified as approaching an end of life condition. For link boxes this can include;

- No compound due to frame distortions;
- No barrier board;
- Obsolete fuse ways and centres;
- Over deep boxes;
- Oversize pavement covers;
- Expanded compound covering contacts; and
- Burnt contacts etc.

Any and all of the above condition issues can result in a dangerous situation for both staff and members of the public due to the potential for explosion. Due to their location (eg on street corners), Outdoor pillars are also often vulnerable to third party interference and vandalism.

Our link box CBRM model has been developed using data as at 31 March 2012 which contains condition data for approximately 40% of installations. It has been assumed the data set is representative of the condition of the link box population as a whole and therefore the number of assets identified by the CBRM model for replacement during the RIIO-ED1 period has been extrapolated to represent the total link box asset population.

The LV Pillar (Outdoor not at substation) CBRM model has also been developed using data accurate as at 31 March 2012 which contains condition data for approximately 80% of installations. The total number of assets identified by the CBRM model for replacement during the RIIO-ED1 period has been extrapolated to represent the total LV Pillar asset population.

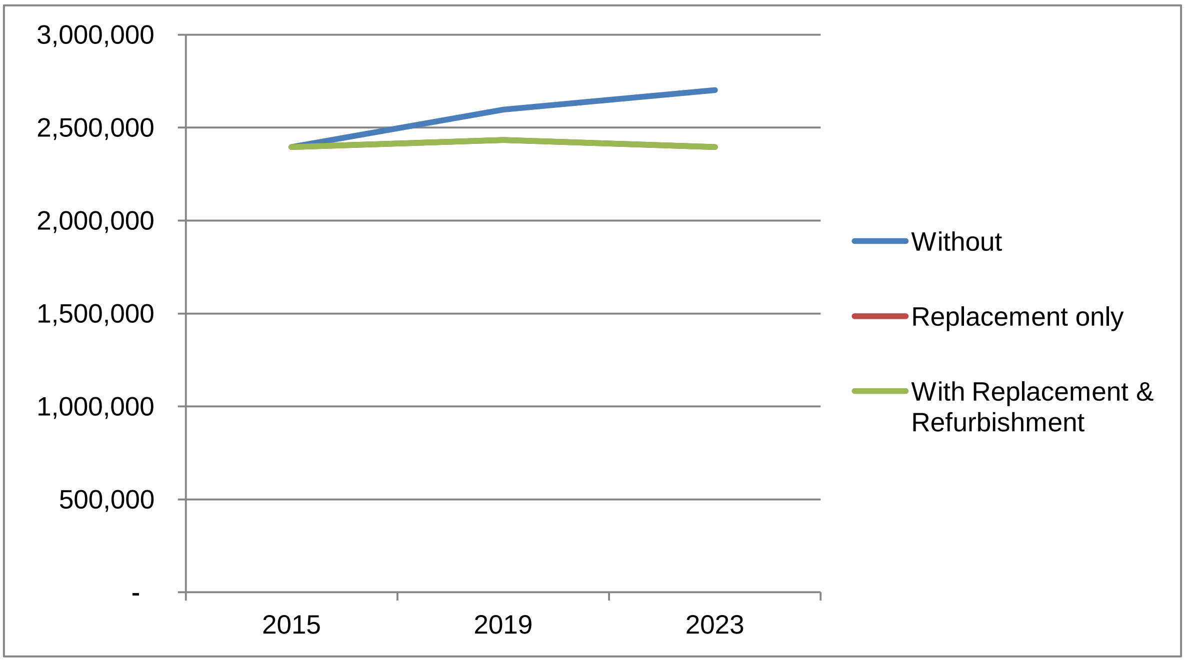
Our proposed programme of work will reduce the risk by 6% compared to the 2015 level.

7.3 LV Woodpoles

These are the wooden poles which support the LV conductors and are predominantly sited in rural areas.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
LV Poles	59,297	5,678	4,162	7%	13%	8.5	5.4

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
59,297	4,162	5.4	12,710	5.2	307,010	34



In DPCR5, we have concentrated on replacing a significant number of poles which have a residual strength calculation of =<80% as part of our ESQCR compliance programme.

This means that we believe we will have replaced the majority of poles that cause any form of non-compliance with ESQCR and therefore in RIIO-ED1 have planned lower replacement volumes on a defect management regime.

With most of the decayed poles removed, the deterioration rate forecast in RIIO-ED1 is modest. In the period we will replace any pole which on inspection has a calculated residual strength value of =<80% at the time of test.

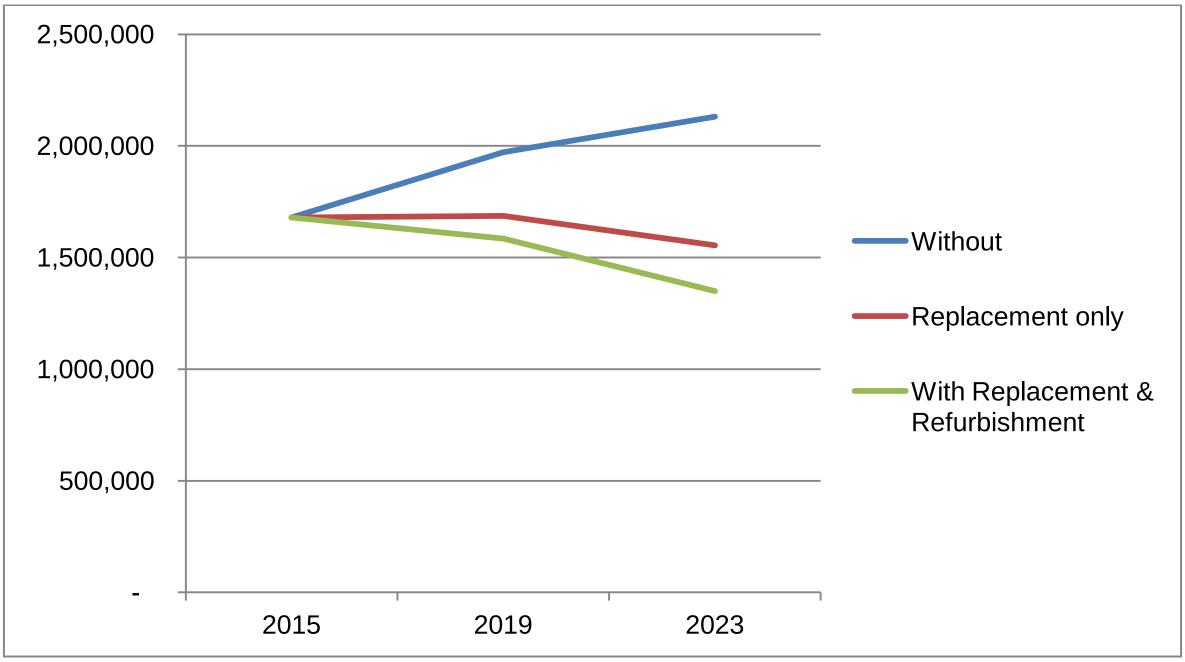
We are already aware from our ESQCR work which poles have a residual strength of in the 81-90% range. We have assumed that these will require replacement in the period and the result of this approach is that risk will be held broadly at its 2015 level across the period.

7.4 HV Switchgear – Primary

These are the units which control the outgoing HV circuits from Primary substations. Although operating at HV, they are usually considered as part of the EHV network.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
6.6/11kV CB (GM) Primary	4,618	240	866	19%	12%	9.0	26.7

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
4,618	866	26.7	358	5.2	781,195	41



For HV primary switchgear, we assess the condition of the fixed and moving portions of our plant. Where the condition of the switchgear has been assessed to be fair except for the moving portion, these have been identified for refurbishment through retrofitting circuit breakers, whose unit costs are lower than asset replacement.

Replacement occurs if the fixed, or fixed and moving portions meet the HI=5 threshold. Refurbishment usually requires replacement of the moving portion with a modern retrofit circuit breaker employing vacuum breaker technology.

Where the fixed portions are at end of life this will either be wholly on current condition such as rusting or distortion of panels etc., or due to issues which place the operator in danger, and hence the switchboard is classed as a safety hazard.

Loss of a panel associated with these multipanel switchboards typically results in a widespread loss of supply and customer inconvenience and takes significant time to restore the system back to the normal running arrangement.

Our intention to use a greater proportion of refurbishment is based on the availability of these techniques and represents a change from our previous practice where virtually every switchboard was replaced.

The CBRM model has been used to identify the HV primary circuit breakers due for intervention. The initial run resulted in approximately 2,000 requiring some form of intervention. This was a result of the exponential ageing of the health of the asset which led to acceleration of HIs. More than 53% of the total asset count are between 40 and 60 years old and are reaching the end of their economic life.

We carried a further review of operability scores of all the assets and this resulted in the reduction of the number of units that required intervention. We then carried out a CBA to determine the appropriate replacement/refurbishment split.

We identified which of the circuit breakers would benefit from refurbishment (retro fit) provided there is no partial discharge and no truck problem.

This asset type had a particularly high peak of installation in the 1960s and a large number of assets are showing signs of coming to the end of their life. As a result, we will be replacing approximately 20% and refurbishing a further 7% of the population in RIIO-ED1 resulting in a reduction in the overall risk score for this asset type.

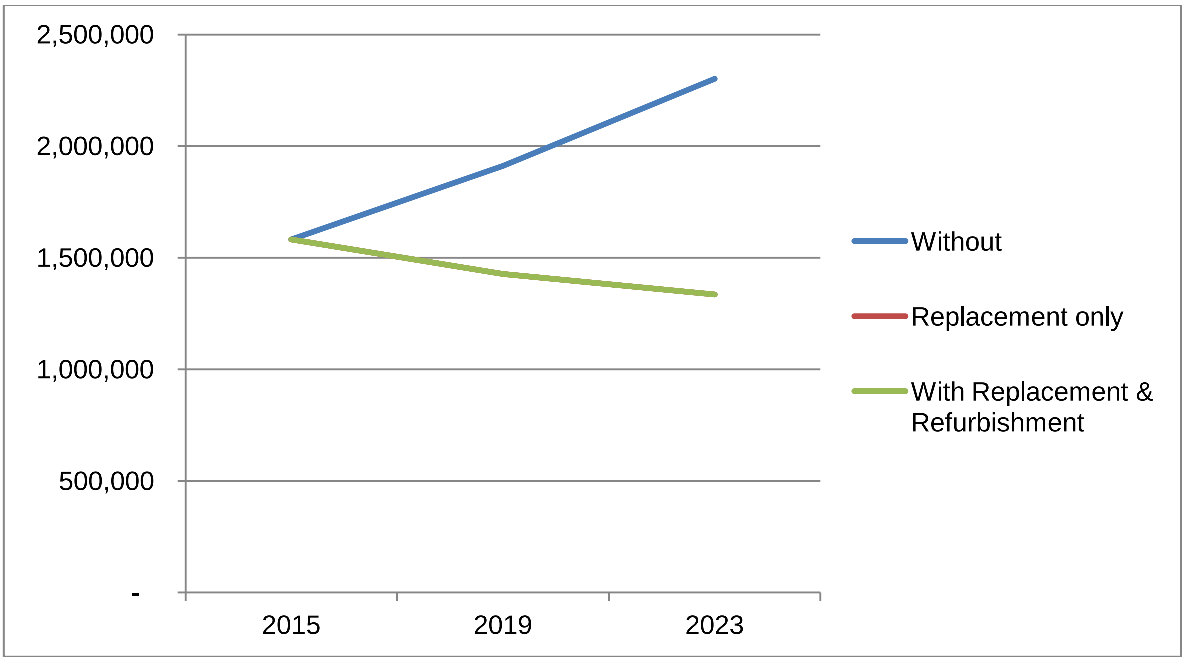
7.5 HV Switchgear – Distribution

These are the switches that operate the transformers at distribution (HV) substations. They are the prime means of controlling the HV network through switching substations on and off.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
6.6/11kV CB (GM) Secondary	5,967	306	1,265	21%	7%	3.2	8.3
6.6/11kV Switch (GM)	13,449	359	2,544	19%	5%	2.4	13.6
6.6/11kV RMU	11,040	871	2,519	23%	8%	9.9	26.2

The category of HV Switchgear - Distribution has been assessed in overall terms (i.e. Switches, Circuit Breakers and Ring Main Units) as the practical solution is to address the entire switchboard on site as the individual items are interrelated. It is not possible to replace individual units (switches and circuit breakers) due to non availability of compatible plant.

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
30,456	8,120	48.1	70	0.6	966,888	50



The HV Switchgear replacement volumes have been identified using the CBRM process and our internal policy (CP352). This details the intervention strategy for specific HV switchgear types.

Partly as a result of a type defect identified on the Long & Crawford/GEC/Alstom GF3 family of oil insulated fuse switches and RMUs, the volume of switchgear replacements required in RIIO-ED1 has increased from that in DPCR5.

In early January 2013, a disruptive failure of a GF3 fuse switch unit occurred shortly after re-energisation following maintenance (see Fig 1 below). A Suspension of Operational Practice (SOP 2013/0383/00) was issued via the Energy Networks Association NEDeRS system on 7th January 2013, pending further investigation. There have been three incidents in Electricity North West where this type of switchgear has failed disruptively.

This SOP prohibits any manual operation of the fuse switch when any part of the unit or switchboard is live.

Aftermath of disruptive failure of GF3 fuse switch at Scale Howe s/stn, Ambleside.

A local remote operation method has since been developed to be used (with restrictions) where remote operation to de energise/energise the fuse switch will result in disconnection of significant numbers of customers or sensitive customers. However, this GF3 fuse switch problem is still causing restrictions in normal operations.

As yet, no modification has been developed to remove the problem and therefore the SOP remains in place.

This defect potentially affects around 11,000 individual switchgear units in our switchgear portfolio which have the GF3 fuse switch mechanism. Further investigation has suggested that fuse switches feeding transformers with a rating of 1,000kVA and above and those feeding radial circuits are at highest risk of failure. This assessment identifies around 2,200 units potentially requiring replacement with an estimated total replacement cost in the order of £20M.

However, as investigations are continuing to positively identify the failure mode and potentially develop a modification, a decision has been taken to only include a portion of the total replacement cost in our RIIO-ED1 submission.

To this end, an additional £12m has been included in our submission to facilitate replacement of the highest risk GF3 units should this prove necessary. This equates to around 1,200 additional assets installed and contributes to the higher than median planned intervention rate.

Replacement ratios

When identifying switchgear replacement solutions, account has been taken of the configuration of the switchgear being disposed of in each substation. Where possible, an existing multiple panel switchboard consisting of two network switches and a transformer circuit breaker will be replaced with a single Ring Main Unit. This results in a higher ratio of switchgear disposals, particularly switches and circuit breakers, to RMU installations.

Replacement of extensible 3 panel switchboard (1 x CB & 2 x Switches) replaced with RMU

The replacement solution for many of the GF3 fuse switches is to replace with a circuit breaker e.g. where a multi-panel switchboard solution is required (more than the typical 2 switch/1 fuse switch configuration) and an RMU solution is not appropriate. This has led to a higher proportion of circuit breakers being installed than would normally be expected from condition based replacement.

For multi-panel boards that require intervention and which have an extensible switchgear configuration with 4 or more units (switches or circuit breakers), it is not practicable to replace individual assets and a total replacement approach is required. This will attract some consequential replacements of units with a Health Index less than 5.

HV switchgear panel requiring extensible switchgear replacement solution

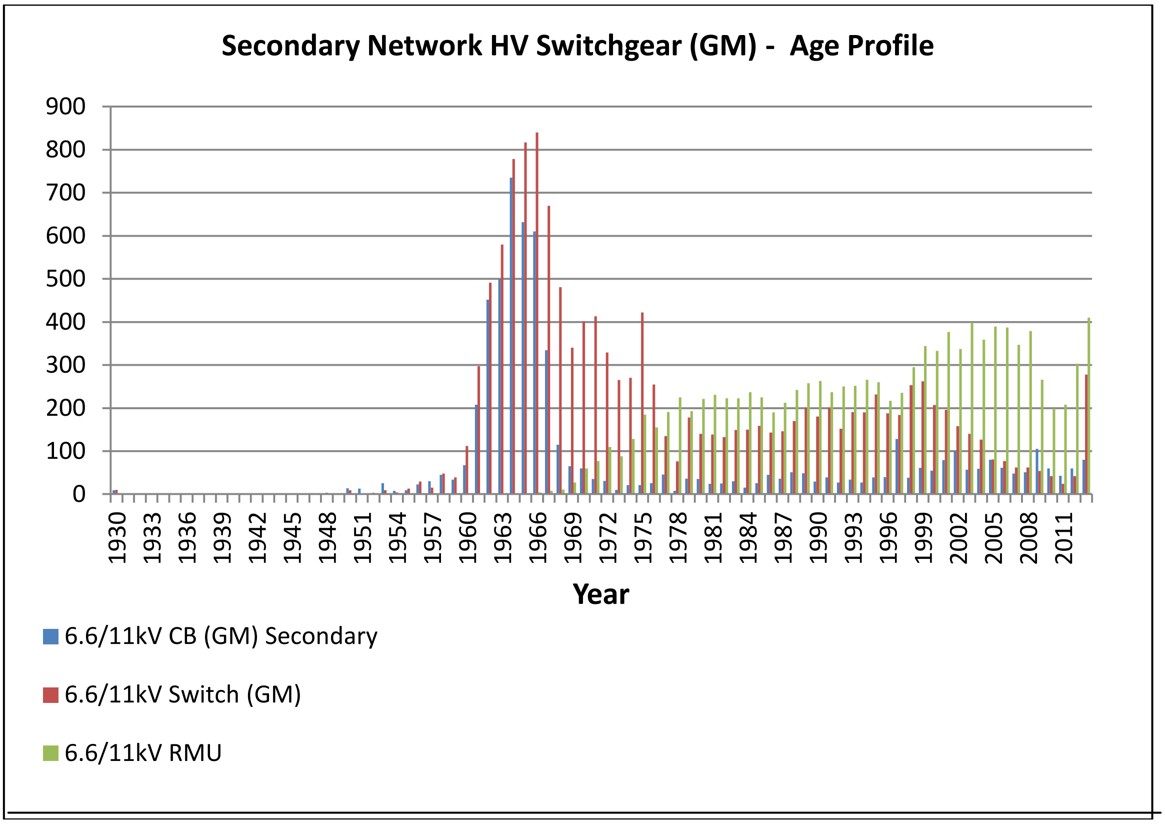
The mix of switchgear types for replacement in RIIO-ED1 is weighted more towards switches and circuit breakers than RMUs which is as a result of the switchgear intervention profile in DPCR5.

During DPCR5, there has been a weighting towards RMU replacements with specific type replacements taking place for operability[1] reasons e.g. Reyrolle ROKSS units due to multiple catastrophic failures and Long & Crawford T3GF3 units manufactured prior to 1973 due to unreliable HV fuse clips.

It should be noted that, whilst switchgear age is not in itself a driver for asset replacement, around 70% of the circuit breaker and switch population will be 45 years of age and older at the end of RIIO-ED1 with a quarter of the circuit breakers being at least 60 years old at that point (see graph below).

In September 2012, Parsons Brinckerhoff (PB) undertook a technical review of our initial RIIO-ED1 submission. Through meetings with staff, and a review of documentation provided, they reviewed our investment plan. In their review of HV switches and RMUs, PB concluded that our expenditure proposals were less than would be expected from an age only view.

[1] Operability is a term used within the Electricity North West Condition-Based Risk Management (CBRM) models to describe a function used to modify the model's output of Health Index as a result of data associated with the plant's reliability.



HV switchgear (GM) age profile

The current issues with the GF3 fuse switch units increase the risk for this asset type above the level we would normally expect. The planned resolution of these issues, together with the replacement of 20% of the asset population over the RIIO-ED1 period results in a 16% improvement in risk from the 2015 position.

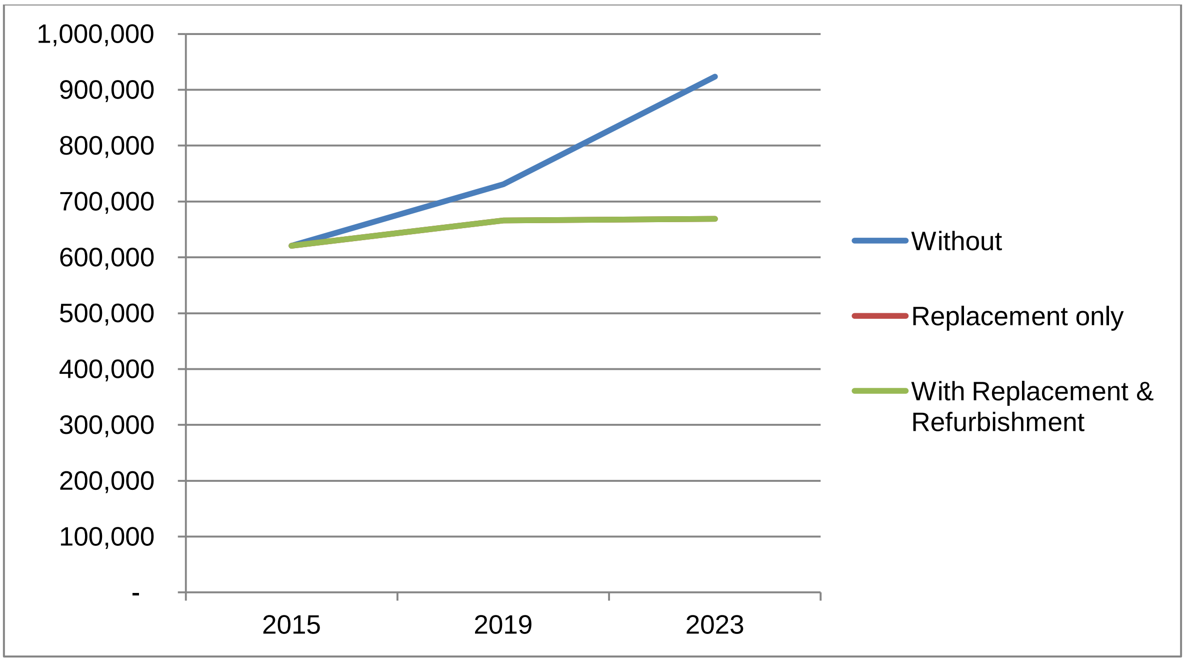
7.6 HV Transformers (GM)

These are the assets that transform the voltage from 33kV to 11 or 6.6kV for onward transmission through the HV network.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	Asset register	DPCR5	RIIO-ED1	Planned	DNO median	DPCR5	RIIO-ED1
6.6/11kV Transformer (GM)	16,679	742	1,408	8%	5%	8.1	18.3

Electricity North West Code of Practice 352 (Guidance Note 3) describes the strategy to be applied in the management of distribution transformers. CBRM modelling has been used to identify ground mounted transformers in poor condition with an expected end of life occurring prior to the end of RIIO-ED1.

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
16,679	1,412	18.3	-	-	254,240	72



Transformer condition is assessed at substation inspection with specific questions being asked about particular condition points. The answers to these questions contribute to the asset Health Index and are weighted to reflect their relative importance with the highest weighting applied to significant corrosion of the main tank and radiators. Oil tests are not routinely taken of distribution transformers.

In addition to those transformers identified for replacement due to their condition, consideration has been given to the number of transformers which will need to be replaced as a consequential output when carrying out LV board and pillar replacements.

Experience has shown that, due to substation and plant assembly arrangements and the space available in the substation, it is not always practicable to replace LV boards and pillars in isolation. There is sometimes a need to replace the existing transformer as well, even if its condition would not normally necessitate replacement.

These replacements are only sanctioned when all other solutions have been explored eg replacing existing LV switchgear with a standalone pillar

Analysis of completed projects shows that around 25% of LV switchgear changes have required the replacement of the transformer as well. This has led to an assumption of 312 consequential transformer replacements being added to the number identified for replacement from CBRM.

The volumes also includes an assumption for consequential transformer replacements from the associated LV board replacement programme due to engineering and compatibility issues for the modern equivalent transformer replacement to accept the existing LV board. From current experience, an assumption has been made that for every ten LV board replacement we anticipate four consequential transformer replacements.

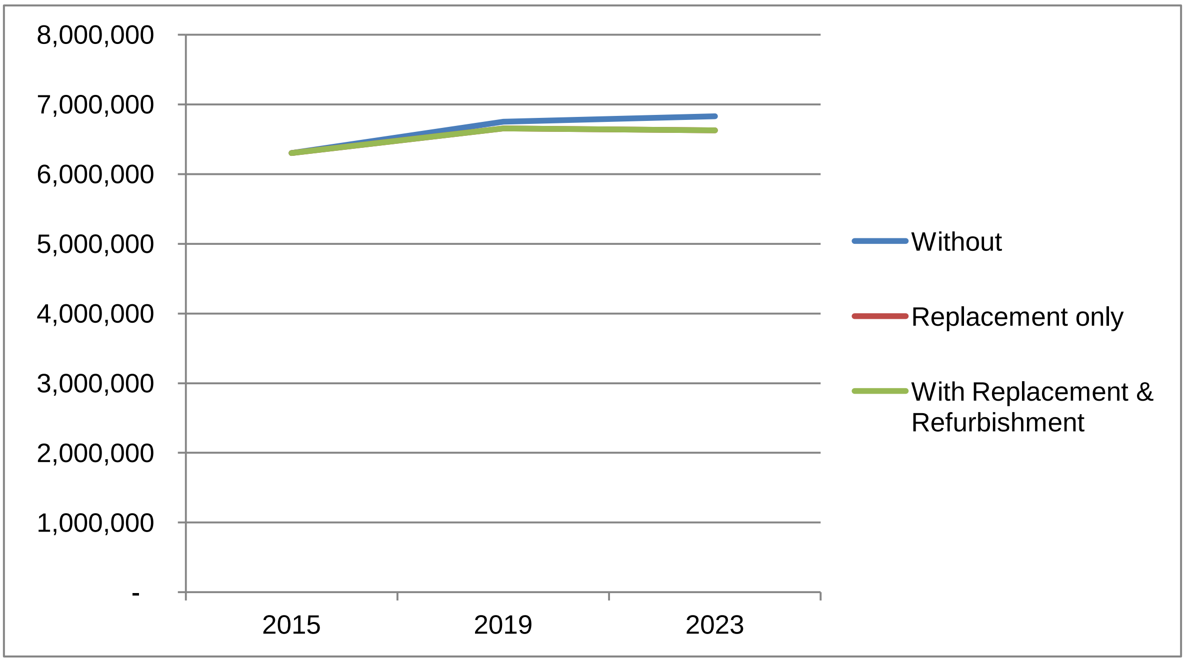
There are no particular special factors in this category and hence the planned programme results in a slight increase in overall risk from that in 2015.

7.7 HV Woodpoles

These are the wooden supports that carry conductors at HV. These are typically found in more rural areas and run between Primary and Distribution substations.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	Asset register	DPCR5	RIIO-ED1	Planned	DNO median	DPCR5	RIIO-ED1
6.6/11kV Poles	98,922	8,153	1,272	1%	7%	13.7	2.1

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
98,922	1,272	2.1	28,212	2.4	199,280	73



The replacement and refurbishment volumes are based on observed condition from on site inspection with intervention determined in line with our internal policy.

Line inspections are carried out by experienced contractors equipped with specialist pole inspection and test equipment. Along with the inspection data collected on hand held devices, photographs are taken of each pole for reference and audit purposes. These photographs are then stored on a central server accessible to those who require it.

Ensuring legal compliance and overall public safety, as well as asset and customer performance, requires a combination of asset replacement and refurbishment appropriate to the risks involved. Efficient asset management relies on the co-ordination of these activities such that maintainable units of overhead line have intervention strategies applied that meet all performance needs.

In DPCR5, we have concentrated on replacing a significant number of poles which have a residual strength calculation of =<80% as part of our ESQCR compliance programme.

This means that we believe we will have replaced the vast majority of poles that cause any form of non compliance with ESQCR and therefore in RIIO-ED1 have planned lower replacement volumes on a defect management regime.

With most of the decayed poles removed, the deterioration rate forecast in RIIO-ED1 is modest. In the period we will replace any pole which on inspection has a calculated residual strength value of =<80% at the time of test.

We are already aware from our ESQCR work which poles have a residual strength of in the 81-90% range. We have assumed that these will require replacement in the period. The result of this approach is that risk will be held broadly at its 2015 level across the period

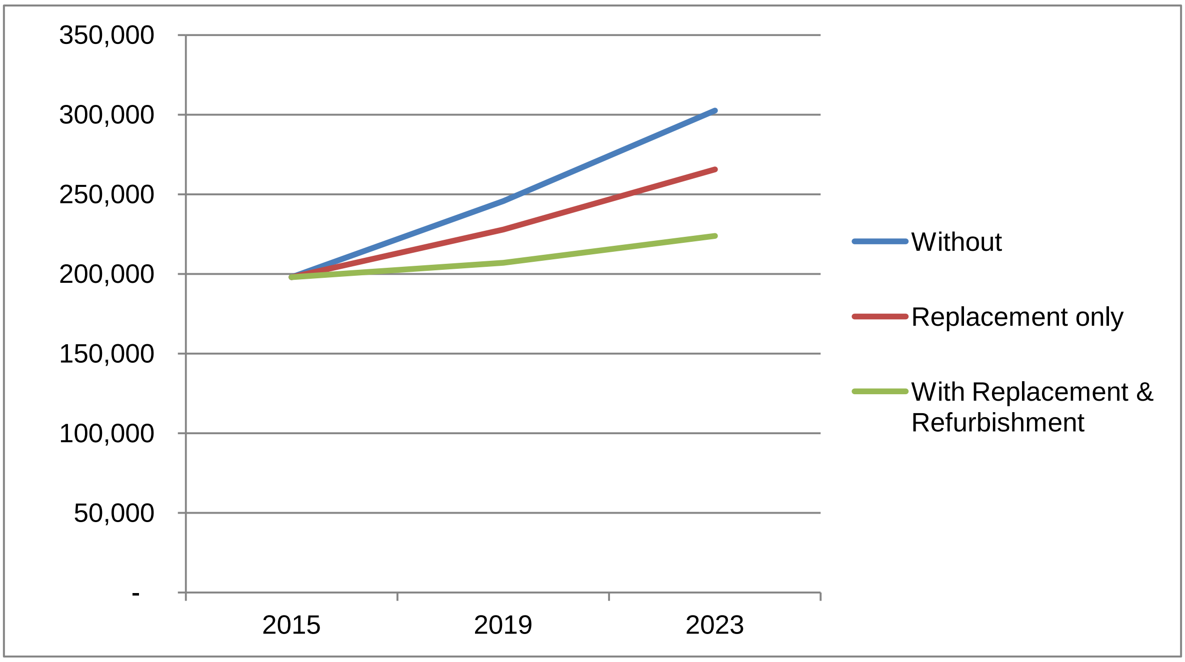
The volumes identified for intervention have been grouped by poles into maintainable units for efficient delivery and to maximise the benefits of investment on those lines in most need of intervention. At the delivery stage, intervention on a section of line will be a mix of replacements and refurbishment.

7.8 EHV Switchgear

This is the switchgear that controls the Primary (eg 33kV) substation and can move supplies from one circuit to another.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV switchgear	1,746	39	69	4%	13%	5.1	5.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
1,746	69	5.0	88	1.2	78,793	79



In this category, we are planning to replace switchgear at Lancaster, Lamberhead, Kirkby Lonsdale and Windermere Primary substations.

The majority of our EHV plant is in reasonable condition with few operability issues. This is partly due to the relatively few operations they undertake when compared with HV Primary boards.

The replacement volumes in RIIO-ED1 reflect the fact that in the past ten years we have refurbished our entire stock of Reyrolle L42T circuit breakers and these in the main are continuing to give good service.

Replacement continues to be the favoured option in most cases as retrofit Circuit Breakers are not available for this category.

With our selective intervention policy, a marked deterioration in the risk position can be seen due to approximately 40 panels of L42T plant which will attain a HI=5 status in the period. These will be reviewed during RIIO-ED1 and an appropriate intervention strategy implemented in RIIO-ED2.

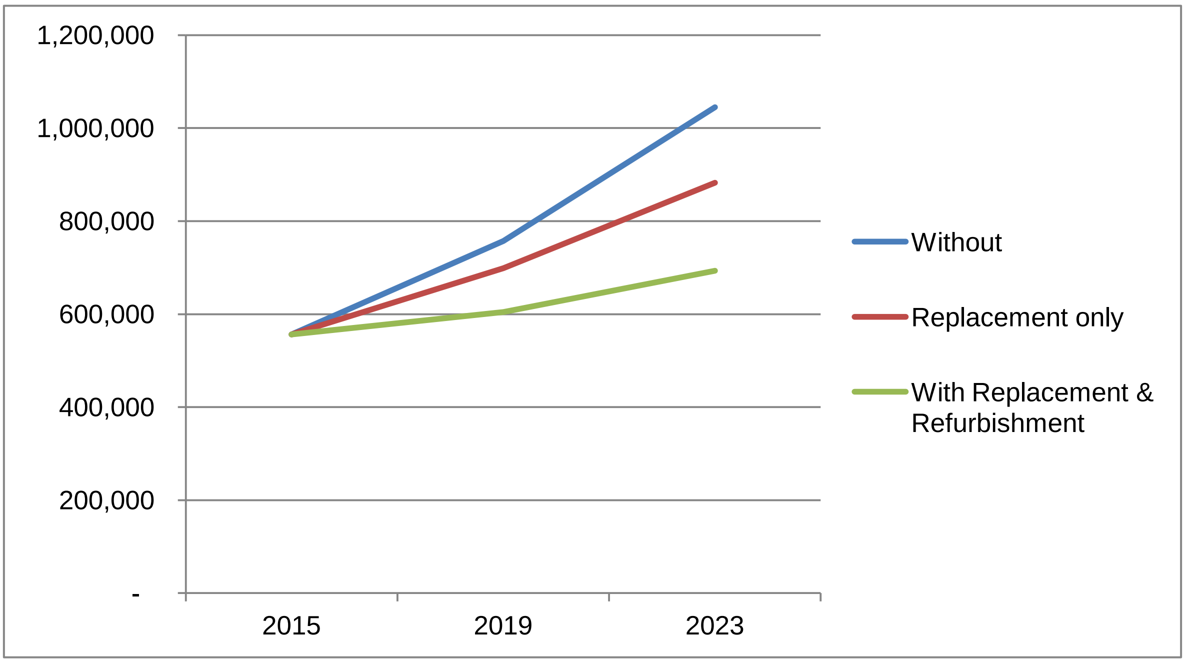
This investment programme is forecast to result in risk increasing by 13% over the RIIO-ED1 compared to the starting point.

7.9 EHV Transformers

These units transform electricity from 33kV to HV (either 11 or 6.6kV) for onward transmission through the HV network.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV Transformer (GM)	718	26	87	12%	8%	8.0	29.4

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
718	87	29.4	109	5.8	352,174	100



In general 33kV GM Transformers for intervention in RIIO-ED1 have been identified using the same process and criteria as used for our 132 kV Transformer population.

A number of differences between the two populations have however become apparent as a result of our investigations into the asset group and these are detailed below.

The CBRM modelling identified approximately 330 out of an asset base of 718 (46%) 33kV transformers which have or will have a Health Index => 5 in the RIIO-ED1 period and hence require intervention. Examination of the specific data has been undertaken and we have identified that due to the exponential ageing system of the model and our life expectancy of a unit which is 60 years coupled with moderate levels of deterioration we have high HI predictions. 59% of our 33kV transformers have been in service for between 40 and 60 years.

The replacement of such high numbers of transformers is neither economically viable nor logistically possible within one RIIO period. As a result, we have carried out further analysis on the transformer HI results based on the set of criteria we jointly developed with Manchester University under the IFI project “Examining Life Extension post Transformer Regeneration.”

This project confirmed that transformer life for Grid and Primary transformers can be extended by an average of 10 years should the oil regeneration be carried out at the right time. We have therefore taken this conclusion into account and only identified transformer units that need to be changed as refurbishment alone will not gain the expected life extension and HI reduction. This process resulted in 87 33kV transformers being identified for asset replacement.

The scope of 33kV transformer replacement includes:

- new transformer,
- a new tap changer,
- replacement of 33kV busbar or cable connections,
- replacement of 6.6/11kV busbar or cable connection,
- new voltage regulation and
- new transformer protection.

It should be noted that in developing our HI for both 132 and 33kV units, the HI of a transformer is a weighted combination of the health index of transformer main tank and on-load tap changer. In determining the intervention required we take into account the following:

- Condition of the unit, both internal and external
- The predominant driver of the overall HI
- Our ability to refurbish against replace the unit
- The potential life extension the proposed intervention will produce
- The impact on the risk presented to the company post intervention and
- The cost benefit from the proposed solution.

In table CV3 we have represented out replacement volumes and costs and in table CV5 our refurbishment volumes and costs. The split is based on a CBA carried out for this asset group.

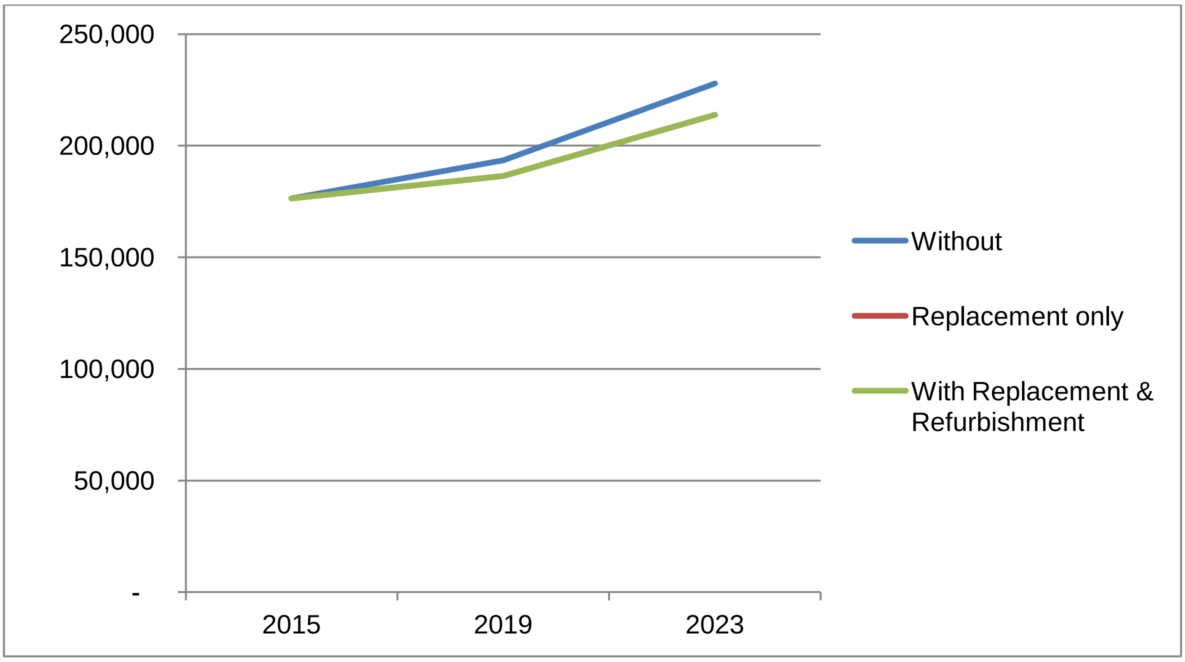
This intervention will result in a risk increase of 25% over the RIIO-ED1 period compared to that at the start of the period.

7.10 EHV UG Cable (gas)

These are 33kV cables that connect major substations and where the insulation is assisted with pressurised nitrogen. These assets were generally installed in the 1950s and 1960s. When replaced, a modern cable of solid construction is used.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV UG Cable (Gas)	234	0	0	0%	0%	0.4	0.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
234	16	0.0	264	4.6	13,998	328



This cable type was installed in the 1960s and 1970s and is now obsolete. No manufacturers exist in the EU and jointing accessories are becoming increasingly difficult to source.

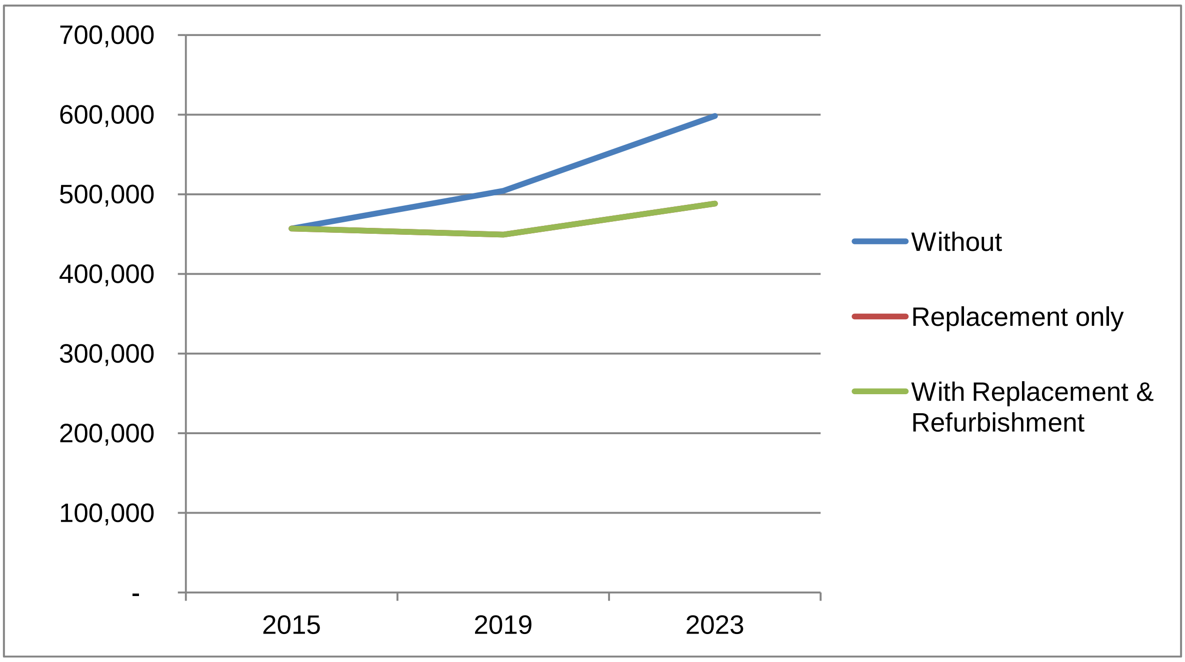
The gas-filled cable system is approaching the end of its design life and has an increasing risk of failure due to lack of expertise, lack of spares, safety issues and the further anticipated deterioration in the reliability of the cables. A programme of replacement of gas cable has been planned for RIIO-ED1 based on leak performance and prioritised on those cables with lead sheaths and phosphor bronze tape reinforcing which experience has shown to be most susceptible to deterioration and leaks.

7.11 EHV UG Cable (oil)

These are 33kV cables that connect major substations and the insulation is assisted with mineral oil under pressure. These assets were generally installed in the 1950s and 1960s. When replaced, a modern cable of solid construction is used.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV UG Cable (Oil)	360	0	0	0%	0%	0.1	0.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
360	45	0.0	160	4.6	109,881	42



As with the gas equivalent, this cable has not been installed for a number of decades, is obsolete and no manufacturers exist in the EU. We are still able to repair faulted cable sections and source jointing accessories but this is becoming increasingly difficult.

At the moment, this asset type is performing very reliably so we are planning a programme of selective replacement based primarily on the risk of environmental contamination from oil leaks.

The majority of the incidents that occur are not as a result of the primary conductor faulting but are associated with the loss of oil. As such, the environmental consequences of faults can be high and this drives the prioritisation of sections for complete replacement.

In terms of interventions, we are able to refurbish joints where oil leaks occur as a result of vibration or land movements.

In RIIO-ED1, we are planning to replace 45km of these assets where they pose a significant risk to the environment and refurbish the majority of the remaining asset base such that it can remain in service until its eventual replacement over the long-term. The result of this planned programme is a restriction in the rise in network risk to 7% from the 2015 position.

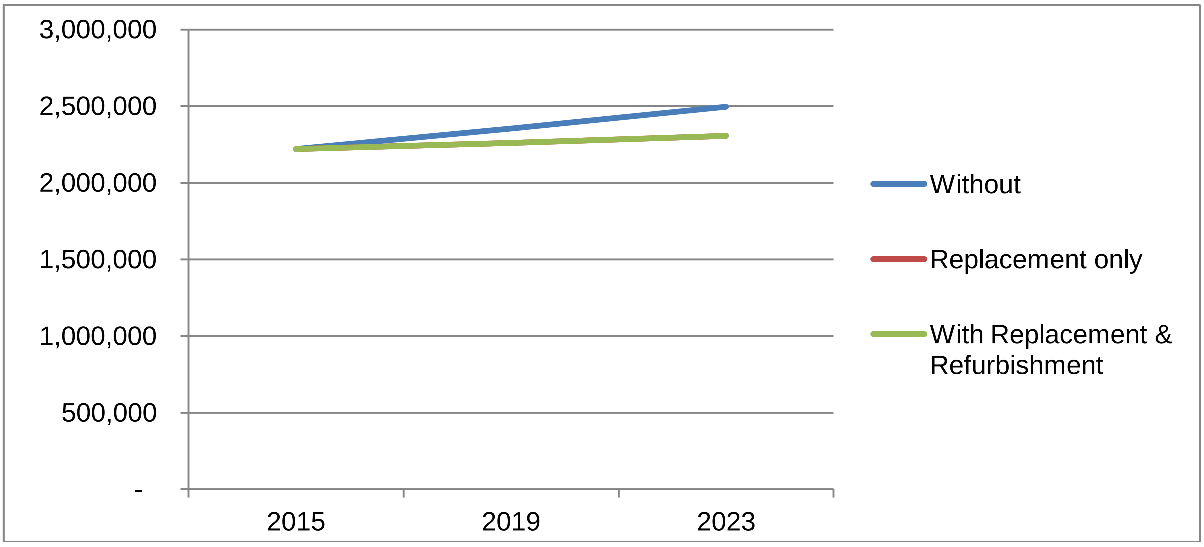
We have produced a CBA which supports our long-term aim of removing all the oil cable on our network at this voltage over the RIIO-ED1, 2 and 3 periods.

7.12 EHV Woodpoles

These are the wooden supports that carry conductors at 33kV.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV Pole	12,567	462	494	4%	12%	1.2	1.5

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
12,567	494	1.5	2,540	1.9	190,026	18



As with LV and HV woodpoles, we have replaced a significant quantity in the DPCR5 period as part of our ESQCR compliance programme. However, due to their nature, EHV woodpoles do not tend to suffer from clearance issues and so the relative volumes replaced are lower than at HV and LV.

Our policy for maintenance and refurbishment of overhead lines was revised and issued in July 2012 and further reviewed in December 2012 to cater for the change from ESQCR compliance investment to intervention and rectification based on observed condition. Development of this policy included review of industry best practice and cost benefit analysis of the modified approach.

For RIIO-ED1, the replacement and refurbishment volumes identified in our plan are based on observed condition from on site inspection with intervention determined in line with our policy.

Line inspections are carried out by experienced contractors equipped with specialist pole inspection and test equipment. Along with the inspection data collected on hand held devices, photographs are taken of each pole for reference and audit purposes. These photographs are then stored on a central server accessible to those who require it.

The volumes identified for intervention have been grouped by poles into maintainable units for efficient delivery and to maximise the benefits of investment on those lines in most need of intervention. At the delivery stage, intervention on a section of line will be a mix of replacements and refurbishment.

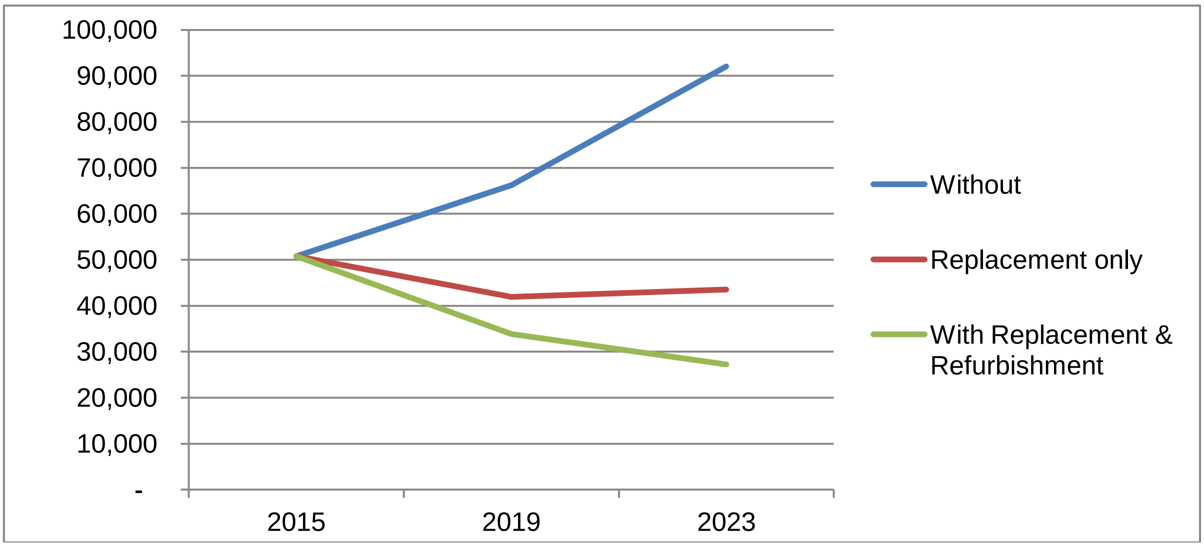
As the forecast deterioration of this asset type is relatively modest, the programme of replacement has been profiled towards the end of RIIO-ED1. Refurbishment of identified poles will take place throughout the period such that the risk will be held broadly constant over the RIIO-ED1 period.

7.13 EHV Towers

These are steel lattice towers that do the same job as EHV woodpoles but are able to carry circuits of a higher rating. Due to their height, they can also be used in areas where woodpoles cannot due to clearance issues.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	Asset register	DPCR5	RIIO-ED1	Planned	DNO median	DPCR5	RIIO-ED1
33kV Tower	930	1	200	22%	2%	0.0	8.1

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
930	200	8.1	364	5.7	64,844	213



Steel lattice tower replacement numbers are based on safety and security data from a full condition survey undertaken in 2012 and used to calculate asset Health Indices using the CBRM model.

The health index for our tower assets can be grouped to allow efficient delivery of interventions at;

- a component level eg insulators, conductor, tower; or
- a circuit level eg a number of towers.

This approach has been used to develop the programme of intervention which has been targeted at reducing probability of failure of individual towers and components. This consists of structures and components being replaced in their entirety where the tower or mast is at end of life and all the bars of the structure require replacement. In addition, the tower's fittings and fixtures are also replaced at this time. It is highly unusual for the entire line to be replaced and intervention is typically a mixture of replacement and refurbishment depending upon the severity of the deterioration. Interventions are usually initiated as a result of the overall line of towers being sufficiently deteriorated to warrant intervention. Replacement may occur when the tower is at HI=4 or 5 and asset refurbishment at HI=4.

In addition, we have a small number of towers (approximately 20 in the DPCR5 period) which need specific and targeted intervention. In this small number of cases (25 estimated for RIIO-ED1) there will be small remediation projects raised to deal with the single structures.

The probability of a complete tower failure is extremely low hence the low starting level of risk. Many of our towers are in exposed conditions and hence it is vital to maintain appropriate painting and refurbishment regimes to ensure a long operating life.

Our strategy incorporates Inspection and Maintenance in accordance with existing policies plus a planned CBRM targeted refurbishment programme matched to the varying life of the overhead line components. Additionally, targeted asset replacement is incorporated into the programme strategy also based on CBRM based condition monitoring of the 33kV Tower assets. This strategy is planned to ensure that tower failures will be minimised even during severe weather conditions, hence ensuring CIs and CMLs are not incurred due to deterioration of the towers. The strategy is also aimed at ensuring that the risk of injury and/or fatality being caused to staff or members of the public due to tower failure is also minimised, even in severe weather conditions.

The tower replacement plan over the last three regulatory periods has focused mainly on the replacement of 132kV towers. Modelling the 33kV tower condition from CDC surveys which took place in 2012 has shown that a number of 33kV towers are required to be intervened on. These can generally be characterised as a mix of tower, fittings and conductor replacements, coupled with a level of tower refurbishment.

The CDC data enables us to study the available photographs of the towers (see above) to determine the number of towers which need to be either replaced or refurbished. Our modelling and investigation shows that we have 222 towers with a health index of 5 that require replacement, however due to system limitations we are unable to achieve this volume of changes. This is because in studying our network we are unable to take the double circuit outages we require to change towers, in the most cost effective manner. It is possible to change towers by the use of temporary structures but this significantly increases the cost to the customer. Our preferred option is to use a refurbishment option as described in our commentary to table CV5. The 33kV towers on our network are small in comparison with the 132kV towers, and as a result we require full outages when replacement or refurbishment work takes place.

Our volumes for the period are further influenced by the deterioration in condition over the last period caused in part by previous painting patterns and the highly corrosive atmosphere of the west coast due to prevailing winds and salt pollution.

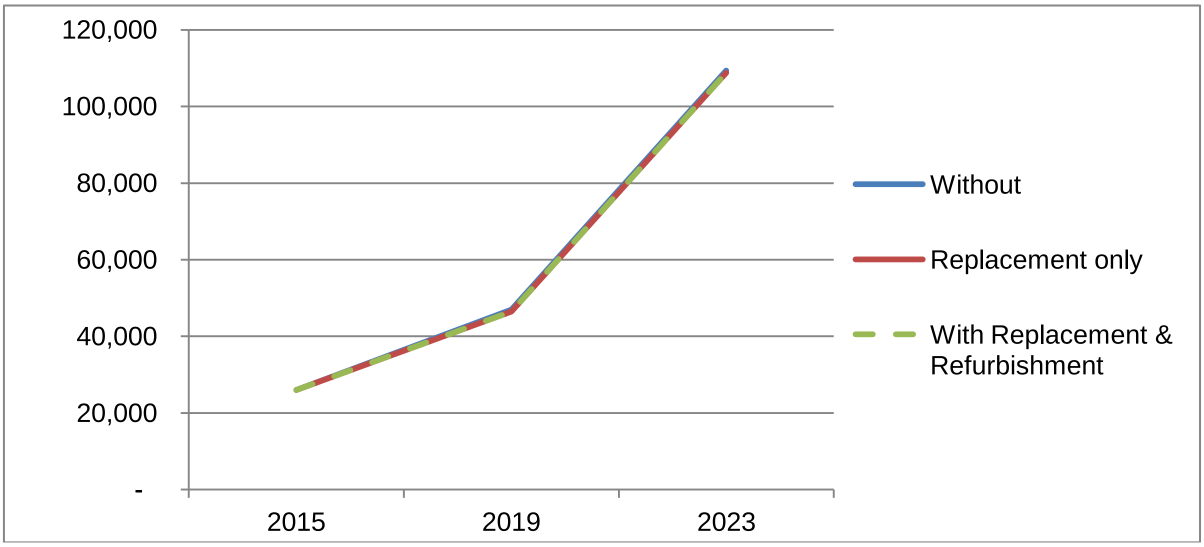
Another consideration which may change our tower replacement / refurbishment requirements is the application by NuGen to National Grid Electricity Transmission for the connection of a 3.6GW nuclear power station, at Moorside near Sellafield. To enable this connection National Grid will need to provide 4 x 400kV transmission circuits. At present, no firm commitments on the timing of the connection works or the route for the transmission circuits have been made.

7.14 EHV Fittings and Conductors

These are the conductors between towers which carry the electricity at 33kV and the fittings that attach the conductors to the towers.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
33kV OHL (Tower line) Conductor	338	15	3	1%	10%	0.6	0.1

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
338	3	0.1			536	243



This is a composite category of conductors and fittings.

Where a tower is replaced, a full set of fittings are changed at the same time. Where fittings only are required these are installed as a separate job.

For 33kV, the volumes of interventions have been relatively low in the period to the end of DPCR5. Inspection data and CBRM modelling now indicates that there are a significant volume of fittings which need to be intervened on.

We have delayed some intervention in DPCR5 as the potential impact of the Moorside nuclear development impacts on many of the lines in the West Cumbria. As the likely date of the commissioning of the new power station has slipped back, there is now a need to intervene on a number of lines. The development of the Moorside project has allowed us to understand the likely retention of the 33kV tower systems in the Cumbria area and hence we are convinced of the need to change this volume of fittings.

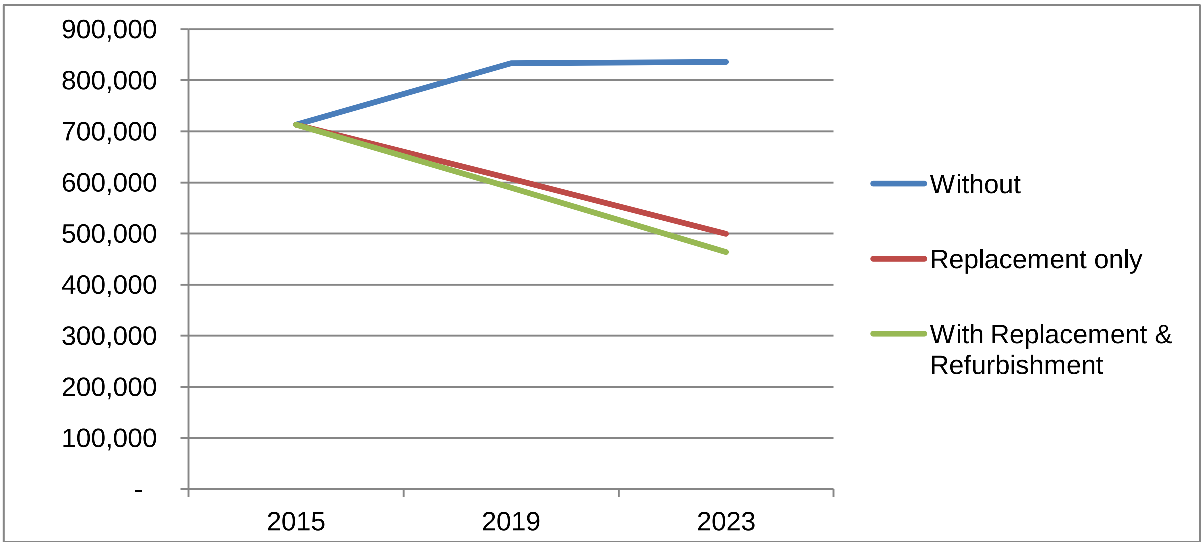
However, as the HI calculation is based on the length of conductor and we are not currently planning to proactively replace any conductor lengths in RIIO-ED1 following the completion of a re-stringing programme in DPCR5, the risk profile shows no reduction from investment over RIIO-ED1.

7.15 132kV CBs

These are our largest units of switchgear, controlling our largest substations where the voltage is transformed down from 132kV to 33kV for onward transmission.

Asset type	Asset register	Volumes (additions)		Intervention Rate		Spend (£M)	
		DPCR5	RIIO-ED1	Planned	DNO median	DPCR5	RIIO-ED1
132kV CB	186	2	31	17%	11%	11	23

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
186	33	23.4	8	0.2	372,202	63



This category covers 132kV CB (Air Insulated Busbars) (ID) (GM), 132kV CB (Air Insulated Busbars) (OD) (GM), 132kV CB (Gas Insulated Busbars) (ID) (GM), 132kV CB (Gas Insulated Busbars) (OD) (GM).

The 132kV switchgear CBRM model was run to identify which assets required replacement. Specific site visits were taken to carry out a physical condition survey to confirm the condition and photos of conditions were taken. Checks were carried out in the DINS and NeDers systems to find out if there were any known type problems for the specific switchgear type.

We have aligned the delivery of the 132kV switchgear replacement programme to the NGET asset replacement works where applicable due to their system outage restrictions.
For 132kV, using the CBRM process, we have identified switchgear at Padiham GSP, Harker GSP (all breakers), Stanah GSP (a specific single breaker) and Peel BSP (all equipment) as requiring replacement.

The 132kV CBs intervention solutions were reviewed following the fast track decision and this has resulted in the reduction of number of CBs installed from 35 to 31. It was judged that whilst the reconfiguration at Peel switching station, with resultant additional CBs, would improve the security of supply to the customers in the Lytham and Blackpool areas it was not cost effective. Notwithstanding the saline environment at Peel, it was decided based on CBA that the solution will be 132kV AIS with associated disconnectors and earth switches. This solution will lead to higher inspection and maintenance costs but the CBA has shown that this is the most cost effective solution.

The intervention solutions for the other two sites at Harker and Padiham were also reviewed. At Harker due to space limitations on site the GIS solution was found to be most cost effective one. At Padiham, space limitations and fluvial flood risk resulted in a GIS solution being the most cost effective. Latest estimates on the costs of the flood alleviation works for the AIS substation are £3.5 million. A GIS solution would design the flood protection into the building at a fraction of this cost. A GIS solution therefore is by far the least cost solution on this site.

Refurbishment is based on historic expenditure on 132kV switchgear. This would traditionally cover CT changes, circuit breaker mechanism and bushing refurbishment.

The potential consequences of a failure at this level of the network results in us taking a considered view of the failure risk compared with other assets, especially due to the potential impact of an N-2 condition existing, which whilst we will be P2/6 compliant we may not be able to adequately restore customer supplies. As a result, the risk for this asset type will reduce significantly over RIIO-ED1; however this is largely due to the planned intervention at a small number of higher risk sites.

We have found limited opportunity to deploy refurbishment solutions as many of the 132kV types of plant which we are using are long out of manufacturer support and often quite bespoke in their design.

Heavily corroded marshalling kiosk at Peel


SF_6 Receiver showing corrosion at Peel

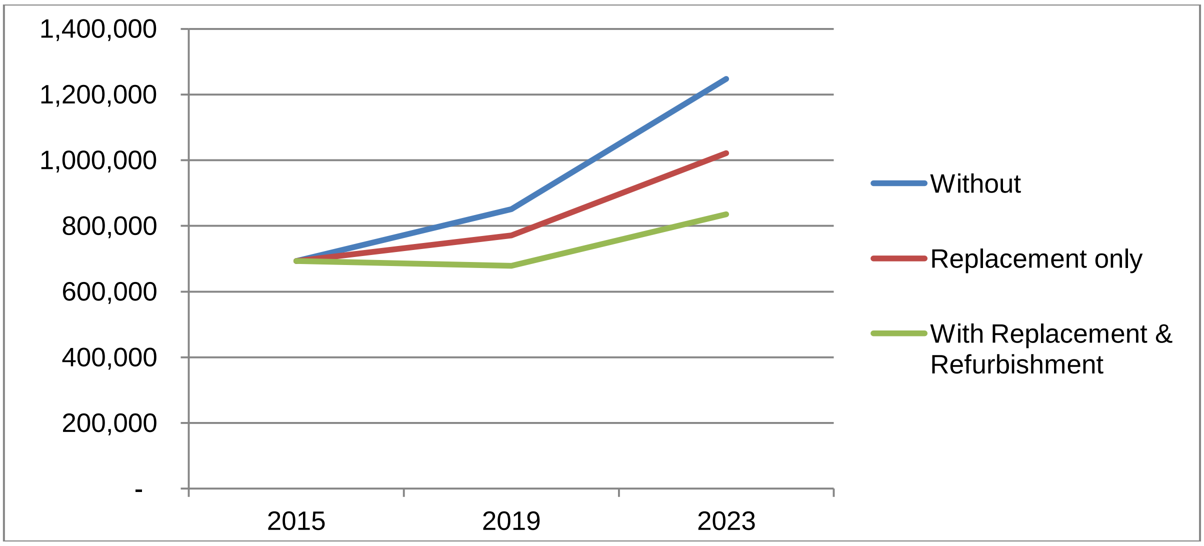

Corroded circuit breaker tank at Padiham

7.16 132kV Transformers

These units transform electricity from 132kV to 33kV where it is transported along EHV circuits to Primary substations.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
132kV Transformer	160	19	17	11%	11%	20.4	17.8

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
160	17	17.8	14	1.1	412,430	46



132kV transformers for intervention are identified through the Grid transformer CBRM model. This uses the data as described in the CBRM explanation at the beginning of this commentary to the CV3 table.

Our CBRM modelling showed a high percentage (29 of 160 or 18%) of Grid Transformer population requiring an intervention in RIIO-ED1 with an additional seven reaching HI5 in the first year of RIIO-ED2. This assessment is based on the as found condition of the units, their operating environment and duty, all of which have significant influence on their ability to perform in a satisfactory manner. The as-found condition includes current oil condition which allows the condition of the internal papers and core to be assessed

This volume assessment is generally in line with median rate for the RIIO-ED1 period. For RIIO-ED2 however, the increase is to some part related to the manner in which our modelling uses an exponential aging system which reflects the experience the industry has gained in over 100 years of existence.

The examination of our data has been carried out in the same manner as detailed in our commentary for our 33kV GM transformer population.

Our Grid transformers are assessed on a unit by unit basis to confirm what level of intervention is required for each unit. We have adopted this approach because the volume of assets is low and the capital cost of replacement is high when compared to other transformer assets.

The unit cost reflects exactly the scope that is required for each unit. The scope of the Grid Transformers to be replaced in RIIO-ED1 includes:

- a new transformer inclusive of cooling system, and as appropriate earthing/ Unit auxiliary transformer,
- new tap changer,
- replacement of 132kV busbar connections so as to marry to the new configuration of the replacement main transformer
- replacement of 33kV busbar connections again to marry to the existing cable connections
- new voltage regulation equipment and
- new transformer protection.

Where there is a need for changes to plinths, fire walls, the addition of bunding or other civil engineering activities the volumes and cost for these activities have been excluded from this table and can be found in table CV6 under the appropriate category for these activities.

It should be noted that in developing our HI for both 132 and 33kV units, the HI of a transformer is a weighted combination of the health index of transformer main tank and on-load tap changer. In determining the intervention required we take into account the following:

- Condition of the unit, both internal and external
- The predominant driver of the overall HI
- Our ability to refurbish against replace the unit
- The potential life extension the proposed intervention will produce
- The impact on the risk presented to the company post intervention and
- The cost benefit from the proposed solution.

In table CV3 we have represented our replacement volumes and costs and in table CV5 our refurbishment volumes and costs. A CBA was carried out to determine the split between replacement and refurbishment.

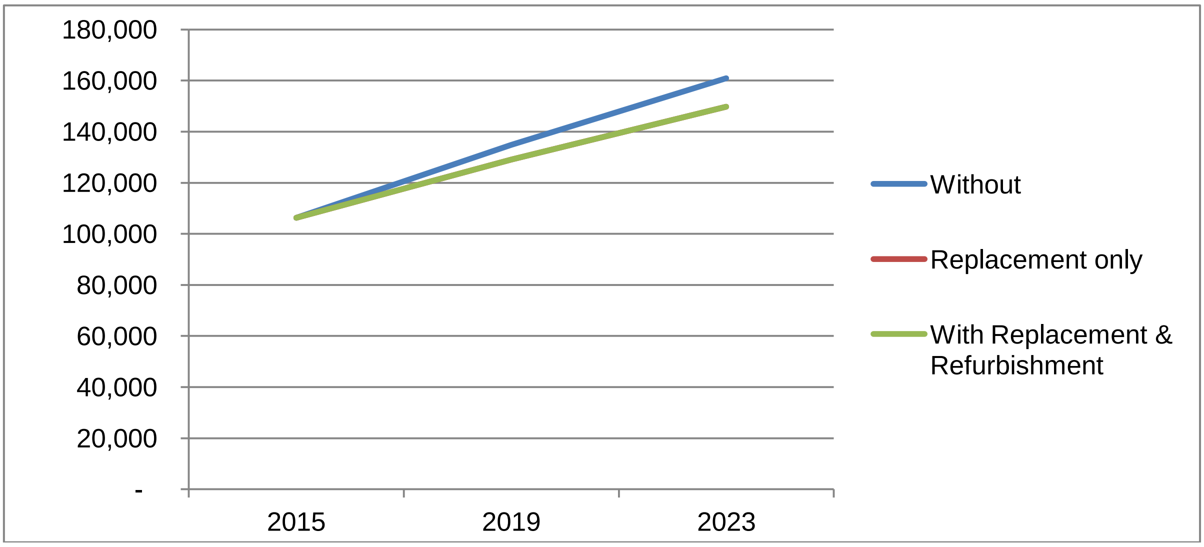
This intervention will result in a risk increase of 20% as it is not economically viable to replace all the transformers that would have reached end of life during RIIO ED1.

7.17 132kV UG Cable (oil)

These are 132kV cables that connect major substations and are insulated with mineral oil. These assets were generally installed in the 1950s and 1960s. When replaced, a modern cable of solid construction is used.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
132kV UG Cable (Oil)	161	0	0	0%	0%	2.2	0.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
161	12	0.0	8	0.6	11,160	51



This asset is managed together with the 33kV equivalent hence the comments set out there also apply to 132kV.

In RIIO-ED1, we have identified EHV cable lengths as being the priority hence the programme for 132kV is comparatively modest. Due to their more robust construction and generally more settled environments (mainly due to being laid more deeply in the ground), these assets generally perform better than their 33kV counterparts.

As a result, despite a programme of selective overlay and refurbishment, risk will rise by 40% over the period; however this should be viewed in the context of recent overlay programmes which have reduced the risk from its previous levels.

Fault information and laboratory reports of cable condition (post fault) are used to identify those cables in worst condition and in most need of intervention. This information is used in conjunction with an assessment of network risk and customer impact to develop the asset replacement programme.

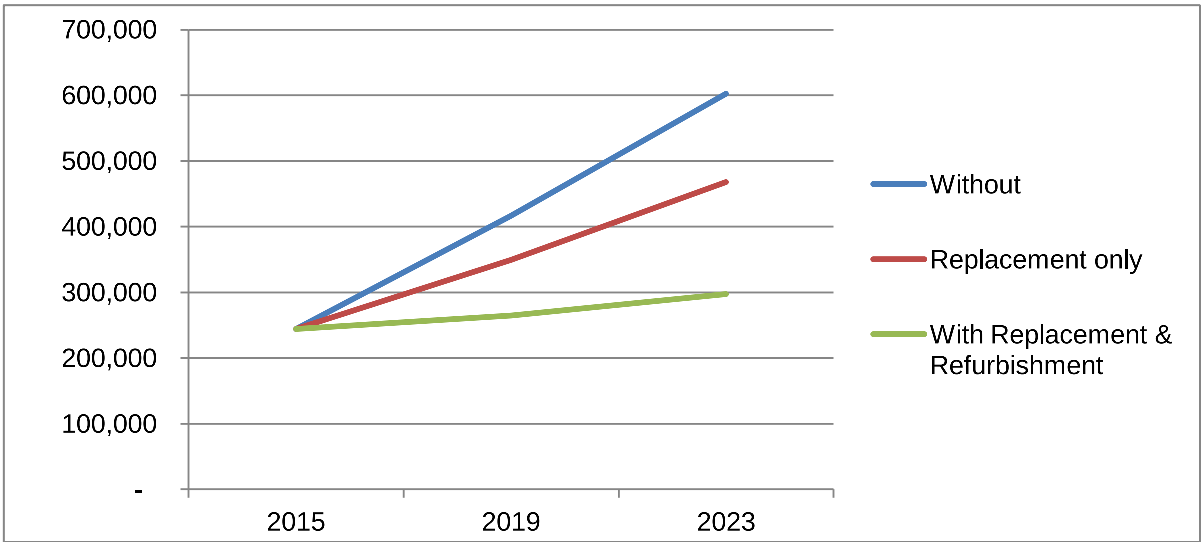
In conjunction with EA Technology, we reviewed our underground cable asset information, via an IFI project, and identified the areas where there is limited health condition information. EA Technology has also identified options to improve the cable asset data information via improved recording of fault information, sample testing, etc. Over the RIIO-ED1 period, we will be investigating ways of improving our knowledge about the performance and degradation behaviour of these assets.

7.18 132kV Towers

These are the large steel lattice towers which support conductors transmitting electricity between major substations at 132kV.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
132kV Tower	3,123	140	200	6%	1%	8.9	15.9

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
3,123	200	15.9	1,892	30.1	304,624	151



Steel lattice tower replacement numbers are based on safety and security data full condition survey data collected in 2012 and used to calculate asset Health Indices using the CBRM model.

The health index for our tower assets can be grouped to allow efficient delivery of interventions at;

- a component level eg insulators, conductor, tower; or
- a circuit level eg a number of towers.

This approach has been used to develop the programme of intervention which has been targeted at reducing probability of failure of individual towers and components. This consists of structures and components being replaced in their entirety where the tower or mast is at end of life and all the bars of the structure require replacement. In addition, the tower's fittings and fixtures are also replaced at this time. It is highly unusual for the entire line to be replaced and intervention is typically a mixture of replacement and refurbishment depending upon the severity of the deterioration. Interventions are usually initiated as a result of the overall line of towers being sufficiently deteriorated to warrant intervention. Replacement may occur when the tower is at HI=4 or 5 and asset refurbishment at HI=4.

The probability of a complete tower failure is extremely low hence the low starting level of risk. Many of our towers are in exposed conditions and hence it is vital to maintain appropriate painting and refurbishment regimes to ensure a long operating life.

We have identified a number of our 132kV tower circuits as being in need of refurbishment and this comprises the bulk of the investment programme on these assets in RIIO-ED1. Completion of this work will result in the overall risk increasing by 20% on its 2015 level through the period.

Our strategy incorporates Inspection and Maintenance in accordance with existing policies plus a planned CBRM targeted refurbishment programme matched to the varying life of the overhead line components. Additionally, targeted asset replacement is incorporated into the programme strategy also based on CBRM based condition monitoring of the 132kV tower assets. This strategy is planned to ensure that Tower failures will be minimised even during severe weather conditions, hence ensuring CIs and CMLs are not incurred due to deteriorated of the 132kV towers. The strategy is also aimed at ensuring that the risk of injury and/or fatality being caused to staff or members of the public due to tower failure is also minimised, even in severe weather conditions.

We have had an extensive programme of tower replacement over the last three regulatory periods. These can generally be characterised as a mix of tower, fittings and conductor replacements, coupled with a level of tower refurbishment, therefore all the volumes for our RIIO-ED1 submission need to be considered in the round, and table CV3 volumes and costs need to be read and modelled with table CV5 volumes and costs.

The CDC data enables us to study the available photographs of the towers to determine the number of towers which can either be replaced or refurbished. Our modelling and investigation shows that we have 430 towers with a Health Index of 5 that require replacement, however due to system limitations we are unable to achieve this volume of changes. This is because in studying our network we are unable to take the double circuit outages we require to change towers, in the most cost effective manner. It is possible to change towers by the use of temporary structures but this significantly increases the cost to the customer. Our preferred option is to use a refurbishment option as described in our commentary to table CV5.

Our volumes for the period are further influenced by the deterioration of the condition over the last period caused in part by previous patterns of painting and the highly corrosive atmosphere of the west coast due to prevailing winds and salt pollution. We anticipate that by the end of the RIIO-ED1 period we will have carried out the vast majority of tower changes required for the foreseeable future based on the condition of the remaining stock.

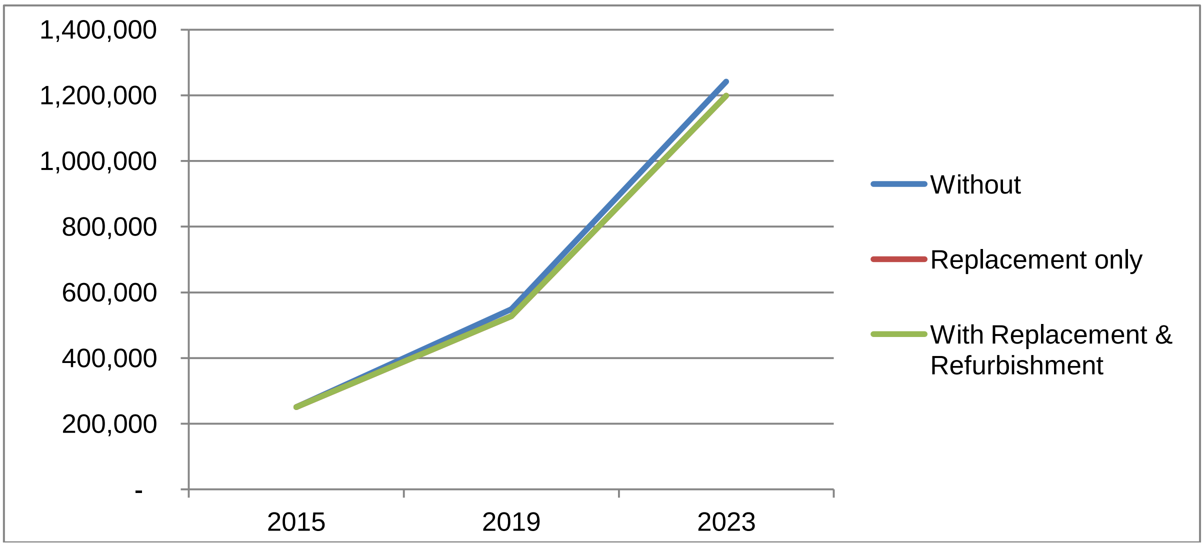
Another consideration which may change our tower replacement / refurbishment requirements is the application by NuGen to National Grid Electricity Transmission for the connection of a 3.6GW nuclear power station, at Moorside near Sellafield. To enable this connection National Grid will need to provide 4 x 400kV transmission circuits. At present, no firm commitments on the timing of the connection works or the route for the transmission circuits have been made.

7.19 132kV Fittings and Conductors

These are the conductors between towers which carry the electricity at 132kV and the fittings that attach the conductors to the towers.

		Volumes (additions)		Intervention Rate		Spend (£M)	
Asset type	**Asset register**	**DPCR5**	**RIIO-ED1**	**Planned**	**DNO median**	**DPCR5**	**RIIO-ED1**
132kV OHL (Tower Line) Conductor	1,595	128	90	6%	17%	9.9	7.0

Population	Planned disposals	£M	Planned refurbishments	£M	Risk points delivered	£/point
1,595	90	7.0			42,556	164



This is a composite category of conductors and fittings.

Where a tower is replaced, a full set of fittings are changed at the same time. Where fittings only are required these are installed as a separate job.

A failure of a conductor or fitting has a lower customer service consequence than a failure of the support itself and is relatively easily repaired without interruption to customers. As a result, ensuring the population of supports is in an appropriate state is the priority for the RIIO-ED1 period. Consideration has also been made of the possibility of significant conductor dismantlement as a result of supplies to the new nuclear power station at Moorside, such that significant re-stringing could result in abortive work. This approach will be kept under review during RIIO-ED1 when greater certainty over the Moorside proposals emerges.

During the DPCR5 period the Health and Safety Executive (HSE) served improvement notice on EDF (now UK Power Networks (UKPN)) following the failure of a number of 132kV insulator strings. As a result of this notice UKPN shared the information with other companies. We reviewed the requirements of the HSE and determined that we would follow suit with UKPN as the HSE made it very clear that this was a course of action they would expect and support. As a result of this, we have created a programme of fitting changes on suspension towers, where the problem has manifested itself in UKPN to mitigate any such issues. This policy is CP430.

As a result of this policy our volumes have been increased to include fittings which need to be changed as a result of routine asset replacement of towers and fittings as well as the conductor fall prevention policy. The basic scope of work in this part of the submission is to replace the insulation strings on both single and double, intermediate, section and terminating towers due to their condition.

The issue documented above only applies to the 132 kV system; we do not have a similar issue with our 33kV networks.

As a result, we are planning to proactively replace around 6% of the current fittings in RIIO-ED1 and this has the effect of reducing the risk from that which it would otherwise have been; however as the HI calculation is based on the length of conductor and we are not currently planning to proactively replace any conductor lengths in RIIO-ED1 following the completion of a re-stringing programme in DPCR5, the risk profile shows little reduction from investment over RIIO-ED1.

ANNEX 3: COST BENEFIT ANALYSIS

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Contents

1. Overview

In developing our business plan we have been particularly focused on ensuring that our plans represent good value for money for our customers and all our stakeholders. Our engagement process clearly identified affordability as a key stakeholder priority.

In considering the range of options available to us as we respond to future challenges, we need to carefully consider the benefits and costs of the different options and ensure that we appropriately take into account the fact that some will be more enduring (longer-lived) than others.

In some areas, we have a level of discretion over whether to undertake any action at all in response to a particular issue. In other areas, the need to do something may be a given, but the exact solution may not be prescribed.

In order to help us make these decisions, we use Cost Benefit Analysis (CBA) assessments to thoroughly test alternative options for our plans. CBA is a well-respected process that most companies use in some form to evaluate different investment options.

We use the CBA methodology in the following two ways:

- For discretionary areas CBA is particularly valuable. Where we have significant discretion over both the timing and scope of interventions it ensures we select the most appropriate option. Discretionary choices that could provide value for our customers and achieve our stakeholders' preferences are evaluated by CBA.
- For non-discretionary areas, CBA may still provide valuable insights. Even when we are required to fulfil an obligation, we have evaluated a range of options utilising the CBA methodology alongside stakeholder engagement where appropriate, to select the most suitable option.

This approach ensures a systematic process by consistently calculating and comparing the benefits and costs of alternative investment options. As part of the CBA, all benefits and costs are expressed in monetary terms to allow a like for like comparison and all future benefits and costs are adjusted for the time value of money to allow the calculation of the Net Present Value (NPV) of the alternative options.

In terms of selecting the preferred option, in the case of entirely discretionary investment, this is generally based on the best positive NPV whereas in the context of mandatory but uncertain interventions, this is often on the basis of the 'least worst' option (ie where all options are negative on a strict NPV basis but where there is mandatory requirement to do something).

For a small number of models we have chosen not to adopt the most advantageous NPV where this is marginal to our proposed solution. This is always associated where the option showing the best NPV has significant delivery, compliance or other risk.

To ensure consistency across all companies, Ofgem have prescribed a particular approach to completing CBA assessments. As part of this process, we have defined a common set of benefits to take into account. This requires the quantification of intangible benefits so that they can be compared against the cost to deliver them.

2. Principles for application

In order to apply CBA effectively, we have developed a set of principles to determine where a CBA is applicable. Generally, any investment subject to a CBA should;

- Be material in terms of the investment it supports;
- Be subject to DNO discretion in terms of potential intervention options; and
- Be capable of having its costs and benefits measured.

In addition to areas not passing the general application principles above, the following have been automatically excluded;

- Any compliance-related expenditure;
- Any investment mandated by government policy or the requirements of the distribution licence; and
- Any investment subject to an uncertainty mechanism.

3. Benefits to be modelled

In order to produce a consistent set of CBAs, a common set of benefits needs to be employed in the benefit modelling. This requires the quantification (where possible) of intangible benefits to be compared with NPV cost functions.

The following are the key benefits modelled in the CBA, together with the prime source of calibration;

Benefit dimension	Measurement
Direct cost incurred	£ NPV
Safety	£ Published Cost of Life data x probabilities of incident
Environment	£ Cost of Carbon (Green Book value), also cost of oil loss
Customer impacts	£ Value of Lost Load or £ IIS incentive rates

These factors are identical to those used in our Risk model (see Annex 2) to ensure consistency between our decision support and risk evaluation tools.

4. Modelling assumptions

The following modelling assumptions have been adopted throughout all the CBA models we have used which are specific to our business.

Parameter	Value used
Pre-tax WACC	4.52%
Losses (£/MWh)	£48.42
CI (£/interruption)	£15.44
CML (£/minute lost)	£0.38
Cost per fatality	£1.79m
Cost per major injury	£30,000

Oil cost	£36/litre

Additionally we have used the following rates which were specified in the model as received from Ofgem.

Discount Rate <= 30 years	3.5%
Discount Rate > 30 years	3.0%
Discount rate for safety	1.5%
Assumed Asset Life (Years)	45

RPI INDICES

Using yearly averages (April to March)

Index		convert to 2012/13
Convert from	2003/04	1.3409
	2004/05	1.3004
	2005/06	1.2670
	2006/07	1.2214
	2007/08	1.1730
	2008/09	1.1392
	2009/10	1.1340
	2010/11	1.0804
	2011/12	1.0309
	2012/13	1.0000

The model also uses rates for carbon trading and assumptions for the decarbonisation of electricity generation, which can be found in Appendix 1 below.

There are also CBA-specific assumptions made which are included in the individual model narratives as appropriate. These include for example forecasts of future period asset replacement volumes.

The CI and CML impact of work for the various options under consideration are outlined in appendix 3.

Our assessments of the risk of injuries or fatalities have been derived based on asset fault rates only. This means for any option based on higher intervention volumes there will be a further increase of risk of injury or fatality over and above the current assumptions as a result of undertaking these higher volumes.

5. CBA application

Our application of CBAs can be broken down into a number of areas, each satisfying the criteria above and representing 'real world' trade-off decisions. The following section goes through the areas where we have applied the CBA approach and gives examples of each.

Asset management regimes

The majority of our network assets are subject to a lifecycle asset management regime which comprises a mix of interventions through an asset's life. These may include inspections, maintenance, painting, component replacement, refurbishment, life extension and replacement. The majority of our proposed network investment costs for RIIO-ED1 are a function of the lifecycle regimes employed.

It is incumbent on us to demonstrate that these patterns of intervention are optimum compared with other alternatives. As a result, we have completed CBAs for each major asset type and compared our proposed investment pattern with at least two alternatives, including a significant scaling back of near-term investment and a significant increase.

For the reduced option, the short-term reduction in investment is traded off against the consequential impact of increased failures and the increased replacement costs over the longer term. For the enhanced option, the additional near-term costs are considered alongside their incidental benefits and reductions in medium-term replacement requirements.

Specific examples include woodpoles, steel tower lines, distribution plant and EHV & 132kV plant.

In this category, we also consider whether there are any additional standalone drivers that may instigate intervention outside of the normal stewardship regime. Examples include the concurrent replacement of co-located assets and the replacement of high loss but otherwise serviceable transformers on the basis of the costed impact of the loss performance.

All options considered are generally do more / do less options. There are no options proposed to do nothing or to run to failure, and all options considered in the CBAs ensure we always remain legally compliant.

When assets do require end-of-life intervention (ie there is a given need to do 'something'), there can be options to refurbish rather than replace at lower cost but these may have a limited future asset life and/or degradation in performance compared to a new asset. Whilst refurbishment can be an option to keep near-term costs down, we need to show that it is the optimum solution in those areas where we have selected it as the preferred intervention option.

Specific examples in this category include the painting and selective member replacement of steel tower lines, replacement and refurbishment of pressurised cable systems and the re-generation of transformer oil.

These CBAs are to be found as AM1-22. These cover the 19 categories for which we present HI profiles, with the 132kV switchgear category covered by three individual scheme CBAs rather than a generic one.

Opportunistic betterment

Where a CBA or other analysis suggests work is required, there are opportunities to add additional functionality or capability at the same time. This could be at lower cost than would be incurred with a standalone installation; however may be sub-optimally targeted. In these instances, we use CBA to ensure that the cost of any additional functionality is justified by its benefits.

Specific examples include the opportunistic upsizing of cable and plant for capacity purposes, incurring an additional cost for lower loss transformers and the installation of remote control functionality on replacement switchgear to improve fault performance.

For the re-submission, we have added CBAs to cover Black Start strategy options following our change in approach in this area, and one for the potential undergrounding of elements of our most extreme rural HV circuits as a potential storm resilience upgrade.

Co-located activities

Where a CBA or other analysis suggests work is required, there are also opportunities to take advantage of the resources (contractors, materials, outages etc.) employed to undertake additional work on adjacent or associated assets on which work may be planned in the future. This would typically result in lower unit costs but risks the replacement of assets which might otherwise still have had a period of useful life remaining.

This issue is most pertinent when replacing plant on distribution substation sites, where the switchgear and transformers may be in different states and have different remaining life left.

These co-located assets are presented in the risk matrices in appendix 2 within HI categories lower than HI 5 as shown by the pink cells.

Unit costs

Unit costs used within the options presented in the CBAs are generally as per the unit costs forecast in the Business Plan Data Template. This is always the case for the costs of replacing assets and also for other associated costs and savings resulting from options. For refurbishment there are some options that are based on a deeper level of refurbishment scope than that presented in the baseline in table CV5, so increased unit costs have been assumed where appropriate.

Smart Grid / Smart Meter solutions

In determining the optimum solutions to load related activities we have incorporated CBA into our planning work in two ways.

For secondary network activities driven by thermal and voltage compliance issues, we have used the Transform model developed under the auspices of the Smart Grid Forum (SGF). This model contains a specific CBA model within the suite of tools and outputs the optimum set of solutions based on the best current view of the cost and benefits from smart solutions. These solutions included the use of Smart Meter data and we have separately detailed in our submission the non-load related benefits of Smart Meter data.

For investment requirements not within the scope of the Transform model; in the main 132kV and 33kV load related investments we have undertaken a general CBA analysis of smart solutions such as Demand Side Response (DSR) against traditional solutions. This analysis clearly shows the value of smart solutions and we have therefore incorporated these into our investment submissions. In order to fully represent the value of smart solutions for these networks in our plan we have deducted a flat 20% from the price of traditional solutions. This represents the average saving attainable across the broad range of investments required, it is of note that many of the technologies required to attain these savings are not yet mature and hence pricing based on a specific technology such as storage is inappropriate.

Smart technologies require a degree of enabling investment in IT systems such as control room network management systems (NMS). This investment is required to co-ordinate and implement smart solutions such as C_2C, CLASS and meshing technologies. This investment is detailed in our Operational IT submission but has not been included in the CBA analysis as it forms part of our strategic investment for both RIIO-ED1 and RIIO-ED2.

6. Options development

Our business processes for developing investment programmes involves the consideration of multiple options when we decide that asset intervention is required. Such consideration is normally applied at programme level, but for our larger projects we undertake this on a site by site basis.

In considering the available options we take a whole life view of all related costs ranging from the initial investment through to the inspections and maintenance costs that will be incurred and effects on safety, environment and network performance. For the purposes of this work, this analysis has been transferred into the CBA template for those assets for which we felt a CBA was appropriate.

For the re-submission, we have re-crafted the options evaluated and added a number of additional CBAs to ensure that every HI category is covered by a bespoke CBA. In these models, the options are based on different portfolios of interventions mapped to the RIIO-ED1 risk matrix – see Appendix 2. This shows the scope of each option within the CBAs using a colour scheme applied to a matrix that shows the combinations of HI and CI ratings that are being included within each option. Different mixes of replacement and refurbishment are considered under these options (and including painting for towers).

Intervention strategies target the replacement of poor condition assets that are reaching end of life, but sometimes we elect to also replace assets at that site that may not be in such a poor state of health. We refer to these as consequential assets. Their replacement is either due to engineering reasons or because it makes economic sense to replace these while we have suitable resources on site even though these assets have remaining life. These consequential assets are separately identified in the CBA scope document in Appendix 2.

For each option under each asset group we have made corresponding adjustments to the medium to long term assumptions of forecast volumes for future RIIO regulatory periods using as a baseline plan our Best View projections used as the basis for Annex 22 – Long-term Strategy. These are outlined in Annex 3a.

We have tabulated the results of the CBAs for all options, as shown in the table below. This shows that while our chosen baseline option represents the lowest NPV in most cases, there are some cases when this is not the case. These are generally where there are engineering or site constraints associated with these options.

NPV Years		Option		
45 years	Study Area	1	2	3
AM1	LV Woodpoles	-20	-25	
AM2	Distribution Switchgear LV	-1	-21	
AM3	LV UGB	0	-5	
AM4	HV Woodpoles	-57	-3	
AM5	Primary Switchgear	-13	-21	-6
AM6	AM HV Switchgear	-2	-5	
AM7	Transformers Distribution	-1	-1	
AM8	Steel Towers Conductors 33kv	-5		
AM9	EHV Woodpoles	-18	-18	
AM10	Steel Towers 33kv	-1	-4	-7
AM11	Oil Cables 33kv	-49	-13	-4
AM12	Gas Cables 33kv	-26	-28	
AM13	EHV Switchgear	-12	-9	-8
AM14	EHV Transformers	-5	-168	-71
AM15	Steel Towers Conductors 132kv	-8		
AM16	Steel Towers 132kv	-0	-42	-45
AM17	Oil Cables 132kv	-88	-98	-124
AM18	Switchgear 132kv Peel	-1		
AM19	Switchgear 132kv Harker	3	-1	
AM20	Switchgear 132kv Padiham	-1	-1	-3
AM21	132kv Transformers	-8	-47	-31
AM22	Black Start	-10	-0	-12
AM23	Undergrounding	-3	-12	18

NO OPTION MODELLED

Further details on the selection of the chosen option are available on the individual CBAs.

Note that the individual 132kV switchgear projects are also covered by individual scheme summaries which give further detail on the options evaluated.

7. CBA schedule

	Area	Model
AM1	AM strategy - woodpoles	LV poles - CBRM (Risk) v Age/Residual strength Mix
AM2	AM strategy - switchgear (distribution)	LV Switchgear - CBRM (Risk) v replacement options
AM3	AM Strategy - LV UGB	LV UGB - Replacement Scenarios
AM4	AM strategy - woodpoles	11kV poles - CBRM (Risk) v Age/Residual strength Mix
AM5	AM strategy - switchgear (primary)	HV primary CBs - CBRM (Risk) v replacement options
AM6	AM strategy - switchgear (distribution)	Secondary HV CBs - CBRM (Risk) v replacement options
AM7	AM Strategy Transformers (Distribution)	Distribution (GM) - CBRM (Risk) v alternative replacement options
AM8	AM strategy - steel towers	33kV Fittings and Conductor - CBRM (Risk) v alternative Replace / Refurbishment mix
AM9	AM strategy - woodpoles	33kV poles - CBRM (Risk) v Age/Residual strength Mix
AM10	AM strategy - steel towers	33kV Towers - CBRM (Risk) v alternative Replace / Refurbishment mix
AM11	AM Strategy - Oil Cables	33kV Oil-filled cable replacement programme
AM12	AM Strategy - Gas Cables	33kV Gas-filled cable replacement programme
AM13	AM strategy - switchgear (EHV)	EHV Switchgear - CBRM (Risk) v replacement options
AM14	AM strategy - transformers (EHV)	EHV - CBRM (Risk) v alternative replacement options
AM15	AM strategy - steel towers	132kV Fittings and Conductor - CBRM (Risk) v alternative Replace / Refurbishment mix
AM16	AM strategy - steel towers	132kV Towers - CBRM (Risk) v alternative Replace / Refurbishment mix
AM17	AM Strategy - Oil Cables	132kV Oil-filled cable replacement programme
AM18	AM strategy - switchgear (132kV)	Peel 132 kV Swgr Replacement
AM19	AM strategy - switchgear (132kV)	Harker 132 kV Swgr Replacement
AM20	AM strategy - switchgear (132kV)	Padiham 132 kV Swgr Replacement
AM21	AM strategy - transformers (132kV)	132kV - CBRM (Risk) v alternative replacement options
AM22	AM Strategy - Black Start Batteries	Black Start
AM23	AM Strategy 11kV OHL to UG Cable	CBA to compare leaving circuits overhead to undergrounding in areas with high tree density to mitigate the effect of storms
L1	Losses Strategy	Losses Strategy 1 33kV 0.2 copper cables replace with 400 triplex
L2	Losses Strategy	Losses Strategy 2 33kV 0.3 copper cables replace with 400 triplex
L3	Losses Strategy	Losses Strategy 3 33kV 185 copper cables replace with 400 triplex
L4	Losses Strategy	Losses Strategy 4 HV 0.1 cables replace with 300 triplex
L5	Losses Strategy	Losses Strategy 5 HV 95PICAS replace with 300 triplex
L6	Losses Strategy	Losses Strategy 6 HV 95 Triplex replace with 300 triplex
L7	Losses Strategy	Losses Strategy 7 LV 0.1 replace with 300 waveform
L8	Losses Strategy	Losses Strategy 8 LV 95 consac replace with 300 waveform
L9	Losses Strategy	Losses Strategy 9 LV 95 waveform replace with 300

		waveform
L10	Losses Strategy	Losses Strategy 10 Transformer 50 PM like for like replacement
L11	Losses Strategy	Losses Strategy 11Transfromer 100 PM like for like replacement
L12	Losses Strategy	Losses Strategy 12 Transformer 200 PM like for like replacement
L13	Losses Strategy	Losses Strategy 13 Transformer 315 GM like for like replacement
L14	Losses Strategy	Losses Strategy 14 Transformer 500 GM like for like replacement
L15	Losses Strategy	Losses Strategy 15 Transformer 800 GM like for like replacement
L16	Losses Strategy	Losses Strategy 16 Transformer 1000 GM like for like replacement
L17	Losses Strategy	Losses Strategy 17 Transformer Grid 45 like for like replacement
L18	Losses Strategy	Losses Strategy 18 Transformer Grid 60 like for like replacement
L19	Losses Strategy	Losses Strategy 19 Transformer Grid 90 like for like replacement
L20	Losses Strategy	Losses Strategy 20 Transformer Primary 10 MVA like for like replacement
L21	Losses Strategy	Losses Strategy 21 Transformer Primary 14 MVA like for like replacement
L22	Losses Strategy	Losses Strategy 22 Transformer Primary 23 MVA like for like replacement
P14R	AM strategy - switchgear (indoor/outdoor)	Switchgear Primary 11kV indoor vs outdoor location
P15R	AM strategy - co-located asset replacement	Co-located asset replacement at distribution substations
P17R	AM strategy - Fault Current Limiter	Primary substation HV CB - defer replacement
S1	Smart Grid Solutions	Smart Grid Solutions - Grid Transformer
S2	Smart Grid Solutions	Smart Grid Solutions - Primary Transformer
S3	Smart Grid Solutions	Smart Grid Solutions - HV Cable

Appendix 1 – Decarbonisation assumptions

Power sector emissions are anticipated to reduce to 10g/kWh by 2050
assume a linear decarbonisation pathway from 2009/10 until 2050

Power sector emissions reduce by 14.5 g/kWh p.a. between now and 2030.
Beyond 2050 keep emissions at 10g/kWh

		g CO2e per kWh	
1,000 kg = 1 tonne	2009/10	589.82	(Defra)
1,000 kWh = 1 MWh	2010/11	575.32	
1 kg = 1,000g	2011/12	560.83	
	2012/13	546.33	
	2013/14	531.84	
	2014/15	517.34	
	2015/16	502.85	
	2016/17	488.35	
	2017/18	473.86	
	2018/19	459.36	
	2019/20	444.87	
	2012/21	430.37	
	2021/22	415.87	
	2022/23	401.38	
	2023/24	386.88	
	2024/25	372.39	
	2025/26	357.89	
	2026/27	343.40	
	2027/28	328.90	
	2028/29	314.41	
	2029/30	299.91	
	2030/31	285.41	
	2031/32	270.92	
	2032/33	256.42	
	2033/34	241.93	
	2034/35	227.43	
	2035/36	212.94	
	2036/37	198.44	
	2037/38	183.95	
	2038/39	169.45	
	2039/40	154.96	
	2040/41	140.46	
	2041/42	125.96	
	2042/43	111.47	
	2043/44	96.97	
	2044/45	82.48	
	2045/46	67.98	
	2046/47	53.49	
	2047/48	38.99	
	2048/49	24.50	
	2049/50	10.00	
	check	10.00	assumption; power sector should

reduce to 10 g CO2e/kWh

14.50	p.a. reduction in carbon intensity

	2012/13 prices	Traded carbon price (£/t 2010/11)[1]	traded carbon price (£/t 2012/13 prices)	Electricity GHG conversion factor (tonnes per MWh)[3]
1	2016	6.76	7.30	0.503
2	2017	7.10	7.67	0.488
3	2018	7.55	8.16	0.474
4	2019	8.03	8.68	0.459
5	2020	8.55	9.24	0.445
6	2021	15.26	16.49	0.430
7	2022	21.97	23.74	0.416
8	2023	28.68	30.98	0.401
9	2024	35.39	38.23	0.387
10	2025	42.10	45.48	0.372
11	2026	48.81	52.73	0.358
12	2027	55.52	59.98	0.343
13	2028	62.23	67.23	0.329
14	2029	68.94	74.48	0.314
15	2030	75.65	81.73	0.300
16	2031	81.00	87.51	0.285
17	2032	88.00	95.07	0.271
18	2033	95.00	102.63	0.256
19	2034	102.00	110.20	0.242
20	2035	109.00	117.76	0.227
21	2036	116.00	125.32	0.213
22	2037	122.00	131.80	0.198
23	2038	129.00	139.37	0.184
24	2039	136.00	146.93	0.169
25	2040	143.00	154.49	0.155
26	2041	150.00	162.05	0.140
27	2042	157.00	169.62	0.126
28	2043	164.00	177.18	0.111
29	2044	171.00	184.74	0.097
30	2045	178.00	192.30	0.082
31	2046	184.00	198.79	0.068
32	2047	191.00	206.35	0.053
33	2048	198.00	213.91	0.039
34	2049	205.00	221.47	0.024
35	2050	212.00	229.04	0.010
36	2051	220.00	237.68	0.010
37	2052	227.00	245.24	0.010
38	2053	234.00	252.80	0.010
39	2054	241.00	260.37	0.010
40	2055	248.00	267.93	0.010

41	2056	256.00	276.57	0.010
42	2057	262.00	283.05	0.010
43	2058	269.00	290.62	0.010
44	2059	276.00	298.18	0.010
45	2060	282.00	304.66	0.010
46	2061	287.00	310.06	0.010
47	2062	292.00	315.47	0.010
48	2063	297.00	320.87	0.010
49	2064	301.00	325.19	0.010
50	2065	305.00	329.51	0.010
51	2066	309.00	333.83	0.010
52	2067	312.00	337.07	0.010

Appendix 2 - CBA scope document for AM-series models

WJPB Ref	Rework Ref	Area	Model	Baseline	Option 1	Option 2	Option 3
P6R	**AM1**	AM strategy - woodpoles	LV poles - Policy	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
				80% HI5 &C1-C4	**100% HI5 &C1-C4**	**Replace all baseline no** Refurb	
P13R	**AM2**	AM strategy - switchgear (distribution)	LV Switchgear (ID, OD at S/S, WM) - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
				33% of HI5 & C1-4	**Excludes HI5C1 in baseline**	**Replace all HI5 (from HI2 Table** Total)	
P20N	**AM3**	AM Strategy - LV UGB	LV UGB & FP - CBRM	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5; N/A
P5R	**AM4**	AM strategy - woodpoles	11kV poles - Policy	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
P11R	**AM5**	AM strategy - switchgear (primary)	HV primary CBs - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5
			Percentage Take Pink only	6 4 11	6 4	6 4 11	6 4
					20% Increase of baseline	**100% HI5 & CI1-4**	
P12R	**AM6**	AM strategy - switchgear (distribution)	Secondary HV Swgr (CB, RMU, SW) - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
			Percentage take	0% 6% 21% 25% 100%	0% 6% 21% 25% 100%	0% 6% 21% 25% 100%	
				77% of HI5 & C2-4	**10% Increase of baseline**	**Replace all HI5**	
P21N	**AM7**	AM Strategy Transformers (Distribution)	Distribution (GM) – CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
P22N	**AM8**	AM strategy - steel towers	33kV Fittings and Conductor - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A	N/A
P4R	**AM9**	AM strategy - woodpoles	33kV poles - Policy	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A
P3R	**AM10**	AM strategy - steel towers	33kV Towers - CBRM	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4; 100% 0%	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5
P1R	**AM11**	AM Strategy - Oil Cables	33 kV Oil-filled cable replacement programme	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5
P19N	**AM12**	AM Strategy - Gas Cables	33kV Gas-filled cable replacement programme	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5; N/A
P10R	**AM13**	AM strategy - switchgear (EHV)	EHV Switchgear - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5
			Percentage Take Pink only		12		
P8R	**AM14**	AM strategy - transformers (EHV)	EHV - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	1 2 3 4 5
			Percentage take				
P24N	**AM15**	AM strategy - steel towers	132kV Fittings and Conductor - CBRM (Risk)	HI 1 2 3 4 5; C1 C2 C3 C4	HI 1 2 3 4 5; C1 C2 C3 C4	N/A	N/A

WJPB Ref	Rework Ref	Area	Model	Baseline	Option 1	Option 2	Option 3
P2R	**AM16**	AM strategy - steel towers	132kV Towers - CBRM	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5 82% (C2, 4) 	1 2 3 4 5	1 2 3 4 5
P18N	**AM17**	AM Strategy - Oil Cables	132kV Oil-filled cable replacement programme	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5	1 2 3 4 5	1 2 3 4 5
P25N	**AM18**	AM strategy - switchgear (132kV)	Peel 132 kV Swgr Replacement	Like for like (GIS CB and AIS BB) 3x CB and 21 disconnectors and E/Sw	GIS indoor, off line build	7x CB off line build (Discounted no cost option)	N/A
P26N	**AM19**	AM strategy - switchgear (132kV)	Harker 132 kV Swgr Replacement	GIS off line build indoor	GIS CB's and AIS BB - Bay by Bay	GIS AIS Off line	N/A
P27N	**AM20**	AM strategy - switchgear (132kV)	Padiham 132 kV Swgr Replacement	GIS to include flood defence integral to building in existing switch yard/compound	Bay by bay Asset Replacement with AIS + Perimeter flood protection, shared funding	Refurbish with Perimeter flood protection	GIS in building but with perimeter flood protection, shared costs in existing yard/compound
P7R	**AM21**	AM strategy - transformers (132kV)	132kV – CBRM (Risk)	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5 9no (C1, 5)	1 2 3 4 5	1 2 3 4 5
			Percentage take	100 (5)	100 (4)	100 (4), 100 (5)	100 (4), 100 (5)
P28N	**AM22**	AM Strategy - Black Start Batteries	Black Start	As New Submission, 78 x Battery Remainder BS's all at end of period	Batteries all sites at EOL Condition from 2020 onwards	Batteries at 78, BS at remainder. Commence All work in FY16	Batteries at all sites regardless of Condition. Commence in FY16
P29N	**AM23**	AM Strategy 11kV OHL to UG Cable	CBA to compare leaving circuits overhead to undergrounding in areas with high tree density	The baseline option assumes we continue to respond to damage and loss of supply at the time of storms as faults repairs. Retain OHL's and existing tree management. Major storm 1 in 4 years	Undergrounding of 2% of lines at high risk of damage during storms due to proximity to trees.	Undergrounding of 5% of lines at high risk of damage during storms due to proximity to trees for the same CI and CML benefit as option 1	Undergrounding of 2% of an increased population of lines at high risk of damage during storms due to proximity to trees with an increased CI and CML benefit over option1 and 2
P14R	NOT RENUMBERED	AM strategy - switchgear indoor/outdoor	Switchgear Primary 11kV indoor vs outdoor location	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5	1 2 3 4 5	1 2 3 4 5
P15R	NOT RENUMBERED	AM strategy - co-located asset replacement	Co-located asset replacement at Distribution substations	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5	1 2 3 4 5	1 2 3 4 5
P17R	NOT RENUMBERED	AM Strategy Fault Current Limiter	Primary substation HV CB - defer replacement	HI 1 2 3 4 5 C1 C2 C3 C4	1 2 3 4 5	1 2 3 4 5	1 2 3 4 5

Key

(red)	Asset Replacement
(amber)	Asset Refurbishment
(green)	Asset Refurbishment (Tower Painting)
(amber-to-red gradient)	Refurb or replace depending on ability to take DC outage.
(pink)	Consequential replacement volumes
(cyan)	Refurbishment of components on poles not resulting in improvement in pole health
(cyan-to-red gradient)	Refurbishment of components on poles not resulting in improvement in pole health together with some pole replacement

Appendix 3 - CI and CML assumptions

												Absolute Baseline position		Option 1		Option 2		Option 3	
Asset type	**Ref**	**Base - Op1**	**Base - Op2**	**Base - Op3**	**Change in CI's per annum Option 1**	**Change in CI's per annum Option 2**	**Change in CI's per annum Option 3**	Customer Interupted	Duration Mins	Applied to Fault Volume	Fault numbers	Total CI	Total CML	Change in CI per annum	Change in CML per annum	Change in CI per annum	Change in CML per annum	Change in CI per annum	Change in CML per annum
LV Poles	AM1	12883	0	0	-2.716%			200	20	100%	0	0	0	0	0				
LV Pillar (ID)	AM2																		
LV Pillar (OD at Substation)	AM2	-1202	3422	3737	0.904%	-2.574%	-2.811%	200	120	100%	83	16600	9960	150.11	90.069	-427.4	-256.4	-466.7	-46.67
LV Board (WM)	AM2																		
LV UGB & LV Pillars (OD not at Substation)	AM3	140	-3510	1215	-0.087%	2.187%	-0.757%	200	120	100%	6	1200	720	-1.047	-0.628	26.244	15.746	-9.082	-0.908
6.6/11kV Poles	AM4	28592	0	0	-17.815%			500	70	100%	0	0	0	0	0	0	0		
6.6/11kV CB (GM) Primary	AM5	-1426	-1413	-1431	0.888%	0.880%		6000	70	100%	0	0	0	0	0	0	0	0	0
6.6/11kV CB (GM) Secondary																			
6.6/11kV Switch (GM)	AM6	-1239	-2599	0	0.509%	1.067%		1000	55	100%	135	135000	7425	686.5	37.758	1440	79.203		
6.6/11kV RMU																			
6.6/11kV Transformer (GM)	AM7	-145	-328	0	0.109%	2.912%		200	55	100%	153	30600	8415	33.253	9.1445	891.05	245.04		
33kV Pole	AM9	2371	0		-2.358%			6000	70	1%	0	0	0	0	0				
33kV OHL (Tower line) Conductor	AM8	-140	0	0	0.980%			6000	70	1%	0	0	0	0	0				
33kV Fittings																			
33kV UG Cable (Oil)	AM11							6000	70	1%	0	0	0	0	0	0	0	0	0
33kV UG Cable (Gas)	AM12	-59	-35		3.148%	1.563%		6000	70	1%	0.53	31.8	0.37	0.01	0.0001	0.005	6E-05	0	0
33kV CB (Gas Insulated Busbars)(ID) (GM)	AM13	-80	-146	-68	5.051%	11.624%	3.586%	6000	70	1%	0	0	0	0	0	0	0	0	0
33kV Transformer (GM)	AM14	-143	-292	-5	2.490%	18.622%	0.184%	6000	70	1%	0	0	0	0	0	0	0	0	0
132kV Tower	AM16	1291	725	725	-5.167%	-4.330%	-11.300%	10000	70	1%	0	0	0	0	0	0	0	0	0
132kV Transformer	AM21	16	1	21	-1.250%	-0.391%	-16.406%	50000	70	1%	0	0	0	0	0	0	0	0	0
132kV OHL (Tower Line) Conductor	AM15	-224			0.389%			50000	70	1%	0	0	0	0	0				
132kV Fittings	AM15																		
33kV Tower	AM10	196	54	54	-2.634%	-1.197%	-1.834%	12000	70	1%	0	0	0	0	0	0	0	0	0

ANNEX 3A: MEDIUM AND LONG TERM VOLUME ASSUMPTIONS IN COST BENEFIT ANALYSIS

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Contents

1. Overview

In developing our Cost Benefit Analysis as outlined in Annex 3, we have investigated various options for each asset group. Where these options involve flexing volumes, we have made corresponding adjustments to the expected volumes in future RIIO-ED periods. We have used as our 'Baseline' the assumptions underpinning our 'Best View' Long-term Strategy as detailed in Annex 22.

These assumptions are documented in the table in section 2.

2. Medium and long term volume assumptions

				REPLACEMENT FORECAST %				REFURBISHMENT FORECAST %			
Rework Ref	**Type**	**Study Area**	**Option**	**RIIO-ED2**	**RIIO-ED3**	**RIIO-ED4**	**RIIO-ED5**	**RIIO-ED2**	**RIIO-ED3**	**RIIO-ED4**	**RIIO-ED5**
AM1	LV	Overhead Pole Line	Baseline	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
			Option 1	0.57%	0.57%	0.57%	0.57%	6.09%	6.09%	6.09%	6.09%
			Option 2	3.90%	3.90%	3.90%	3.90%	1.00%	1.00%	1.00%	1.00%
			N/A								
AM4	HV	Overhead Pole Line	Baseline	10.00%	12.00%	12.00%	12.00%	10.00%	12.00%	12.00%	12.00%
			Option 1	0.11%	0.11%	0.11%	0.11%	6.55%	6.55%	6.55%	6.55%
			Option 2	1.57%	1.57%	2.50%	3.00%	1.00%	1.00%	1.00%	1.00%
			N/A								
AM9	EHV	Overhead Pole Line	Baseline	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
			Option 1	0.66%	0.66%	0.66%	0.66%	6.01%	6.01%	6.01%	6.01%
			Option 2	1.97%	1.97%	1.97%	1.97%	1.00%	1.00%	1.00%	1.00%
			N/A								
AM8	EHV	Overhead Tower Line (Fittings and Conductors)	Baseline	2.00%	3.00%	9.00%	12.00%	2.00%	3.00%	9.00%	12.00%
			Option 1	1.50%	2.00%	8.00%	10.00%	1.50%	2.00%	8.00%	10.00%
			Option 2	4.00%	6.00%	11.00%	15.00%	0.50%	1.00%	4.00%	6.00%
			Option 3	4.00%	6.00%	11.00%	40.00%	4.00%	4.00%	4.00%	4.00%
AM15	132kV	Overhead Tower Line (Fittings and Conductors)	Baseline	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
			Option 1	3.00%	4.00%	4.00%	4.00%	1.50%	2.00%	8.00%	10.00%
			N/A								
			N/A								
AM17	132kV	Cable	Baseline	10.00%	25.00%	1.00%	1.00%	10.00%	25.00%	1.00%	1.00%
			Option 1	12.50%	27.00%	1.00%	1.00%	10.00%	17.50%	0.00%	0.00%
			Option 2	15.00%	30.00%	1.00%	1.00%	7.50%	5.00%	0.00%	0.00%
			Option 3	17.50%	32.50%	1.00%	1.00%	15.00%	15.00%	7.50%	1.00%
AM7	HV	GM Transformers	Baseline	12.00%	10.00%	10.00%	10.00%	12.00%	10.00%	10.00%	10.00%
			Option 1	11.34%	10.00%	10.00%	10.00%				
			Option 2	10.06%	10.00%	10.00%	10.00%				
			N/A								
AM14	EHV	Transformers	Baseline	10.00%	10.00%	11.00%	11.00%	10.00%	10.00%	11.00%	11.00%
			Option 1	8.00%	8.00%	15.00%	15.00%	11.00%	12.00%	14.00%	16.00%
			Option 2	20.00%	20.00%	22.00%	22.00%	5.00%	5.00%	5.00%	5.00%
			Option 3	17.50%	17.50%	20.00%	20.00%	7.50%	8.50%	9.50%	6.00%
AM21	132kV	Transformers	Baseline	8.00%	8.00%	10.00%	10.00%	8.00%	8.00%	10.00%	10.00%
			Option 1	8.00%	8.50%	16.00%	17.00%	11.00%	12.00%	15.00%	17.00%
			Option 2	20.00%	20.00%	22.00%	22.00%	5.00%	5.00%	5.00%	5.00%
			Option 3	17.50%	17.50%	20.00%	20.00%	7.50%	8.50%	9.50%	6.00%
AM2	LV	Switchgear (LV boards and pillars at s/stns)	Baseline	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
			Option 1	2.68%	10.00%	10.00%	10.00%				
			Option 2	5.00%	8.00%	8.00%	8.00%				
			N/A								
AM3	LV	Switchgear (Link Boxes & Feeder Pillars)	Baseline	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
			Option 1	10.70%	10.00%	10.00%	10.00%				
			Option 2	2.50%	2.50%	7.50%	10.00%				
			N/A								
AM5	HV	Switchgear Primary CB	Baseline	12.00%	10.00%	10.00%	8.00%	12.00%	10.00%	10.00%	8.00%
			Option 1	6.00%	3.00%	3.00%	2.00%	6.00%	3.00%	3.00%	1.00%
			Option 2	9.00%	5.00%	5.00%	5.00%	9.00%	5.00%	5.00%	1.00%
			Option 3	2.00%	1.00%	1.00%	1.00%	2.00%	1.00%	1.00%	1.00%
AM6	HV	Secondary Network GM Switchgear (SW, CB & RMU)	Baseline	12.00%	10.00%	10.00%	8.00%				
			Option 1	7.93%	10.00%	10.00%	8.00%				
			Option 2	3.47%	10.00%	10.00%	8.00%				
			N/A								
AM13	EHV	Switchgear	Baseline	5.00%	9.00%	10.00%	8.00%	5.00%	9.00%	10.00%	8.00%
			Option 1	4.00%	8.00%	10.00%	15.00%	11.00%	13.00%	17.50%	20.00%
			Option 2	5.00%	18.00%	20.00%	16.00%	5.00%	4.50%	6.00%	4.00%
			Option 3	4.00%	15.00%	17.50%	10.00%	6.00%	5.00%	8.00%	6.00%
AM12	EHV	Gas Cable	Baseline	10.00%	15.00%	8.00%	8.00%	10.00%	15.00%	8.00%	8.00%
			Option 1	10.00%	17.50%	8.00%	8.00%	10.00%	17.50%	0.00%	0.00%
			Option 2	12.50%	20.00%	8.00%	8.00%	7.50%	5.00%	0.00%	0.00%
			Option 3	5.00%	10.00%	30.00%	30.00%	15.00%	15.00%	7.50%	1.00%
AM16	132kV	Steel Towers	Baseline	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
			Option 1	3.00%	4.00%	4.00%	4.00%	1.50%	2.00%	8.00%	10.00%
			Option 2	10.00%	10.00%	8.00%	8.00%	0.50%	1.00%	4.00%	6.00%
			Option 3	4.00%	4.00%	4.00%	45.00%	6.00%	6.00%	6.00%	6.00%
AM10	EHV	Overhead Tower Line	Baseline	2.00%	3.00%	9.00%	12.00%	2.00%	3.00%	9.00%	12.00%
			Option 1	1.50%	2.00%	8.00%	10.00%	1.50%	2.00%	8.00%	10.00%
			Option 2	4.00%	6.00%	11.00%	15.00%	0.50%	1.00%	4.00%	6.00%
			Option 3	4.00%	6.00%	11.00%	40.00%	4.00%	4.00%	4.00%	4.00%

ANNEX 4: SUPPORT TO ELECTRICITY NETWORK DEMAND FORECASTS BY CEPA

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UPDATE TO "SUPPORT TO ELECTRICITY NETWORK DEMAND FORECASTS"

A REPORT FOR ELECTRICITY NORTH WEST LIMITED

19 January 2013

FINAL REPORT

Submitted by:

Cambridge Economic Policy Associates Ltd

CONTENTS

Executive Summary

Cambridge Economic Policy Associates (CEPA) provided support to ENWL's electricity demand forecasting work in early 2012. The present report documents our updates to that work and new results. The updates were focused on two questions: how would we change our results for the period to 2022/23 in the light of the latest available data, and how would we extend them to 2030/31.

Approach

In addressing the first question – the need to change our results to 2022/23 - we have focused on changes to input assumptions rather than to the structure of our economic model. We have re-run our regression analysis to update the co-efficients in our economic models to reflect the latest year of historic data, but not changed the factors ("exogenous variables") themselves.

We have also reviewed the public forecasts of these factors. These were sourced largely from UK Government publications, such as those from the Office for National Statistics and the Office for Budget Responsibility.

In addressing the second question – extending the results to 2030/31 – we have sourced data for the additional years from the same sources as before, where available. Where this data was not available, we assumed a continuation of existing trends.

Results

Our economic models are very similar to those from our previous work, although they do show a slightly higher sensitivity to prices and income. Our input assumptions in general show lower projected growth than for our previous work. This leads to our projections all being significantly *lower* than those from our previous work.

The main driver for this is that the Office of Budget Responsibility has revised its forecasts of economic growth down significantly since this time last year. This means that our projections of commercial and industrial demand growth, in particular, are lower. There are also some small reductions in domestic demand growth because of reductions in forecasts of household growth and household income. In all but one scenario, demand does not return to current levels until after 2020.

1. INTRODUCTION

This report documents the results of an update to the electricity demand work that Cambridge Economic Policy Associates (CEPA) carried out for ENWL in early 2012. The results of that work were provided to ENWL on 8 March 2012[1].

As required, this update has reviewed the original work to check that its conclusions were still valid, and extended the results up to, and including, the year 2030/31. That is, the results now cover the regulatory periods RIIO-ED1 and RIIO-ED2. The results were also updated to use 2011/12 as the base year.

The rest of this document is structured as follows:

- Section 2 briefly sets out the approach we have taken, which followed the approach set out in our proposal to ENWL[2]. We also describe any issues that we found and how we resolved them.
- Section 3 describes the changes to the model, including as a result of the 2011/12 data received from ENWL.
- Section 4 describes our results, including a comparison of those results to the results of the original study.

A list of data sources is in Annex A. Annex B includes a short narrative description of each scenario, and a summary of the key inputs for each. The economic model equations are in Annex C. An explanation of the exogenous variables (or "factors") that we considered is in Annex D.

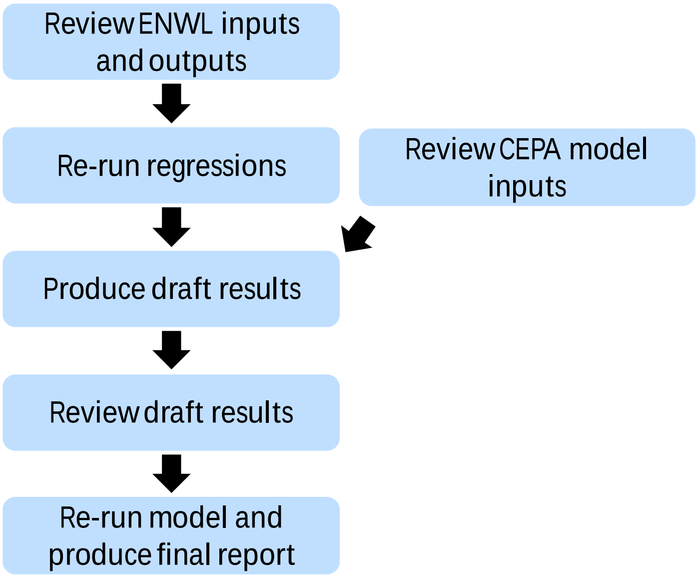
[1] "*ENWL demand forecasts final.zip*", sent to Dr Rita Shaw from Iain Morrow on 8 March 2012.
[2] "*Proposal for update to demand forecasting FINAL.pdf*", sent to Dr Victor Levi on 20 November 2012

2. APPROACH

Our approach to this work was as set out in our proposal to ENWL, dated 20 November 2012. We reproduce this below for ease of reference.

Our approach had six stages, as Figure 2.1 below illustrates.

Figure 2.1: Outline of approach



Each stage is described by one of the sections below.

2.1. Review ENWL inputs and outputs

In this stage, we did an initial sense-check on the data received from ENWL, including comparing it with previous data, previous projections and other data sources where available.

This found no major issues. The only query was about data provided for November 2012. We confirmed with ENWL that they wished us to use the December 2011 data as the baseline.

We have also reviewed the updated output spreadsheet provided by ENWL. There were no issues.

2.2. Re-run regressions

We re-ran our regression analysis to allow the model to take account of the additional year of historic data. This gave us our updated models, which we set out in section 3, including showing how they differ from the previous models.

In summary, the models are not significantly different although they do show a slightly higher sensitivity to price and income changes.

2.3. Review CEPA inputs

We also reviewed the CEPA inputs. This had three parts.

2.3.1. Use of latest data

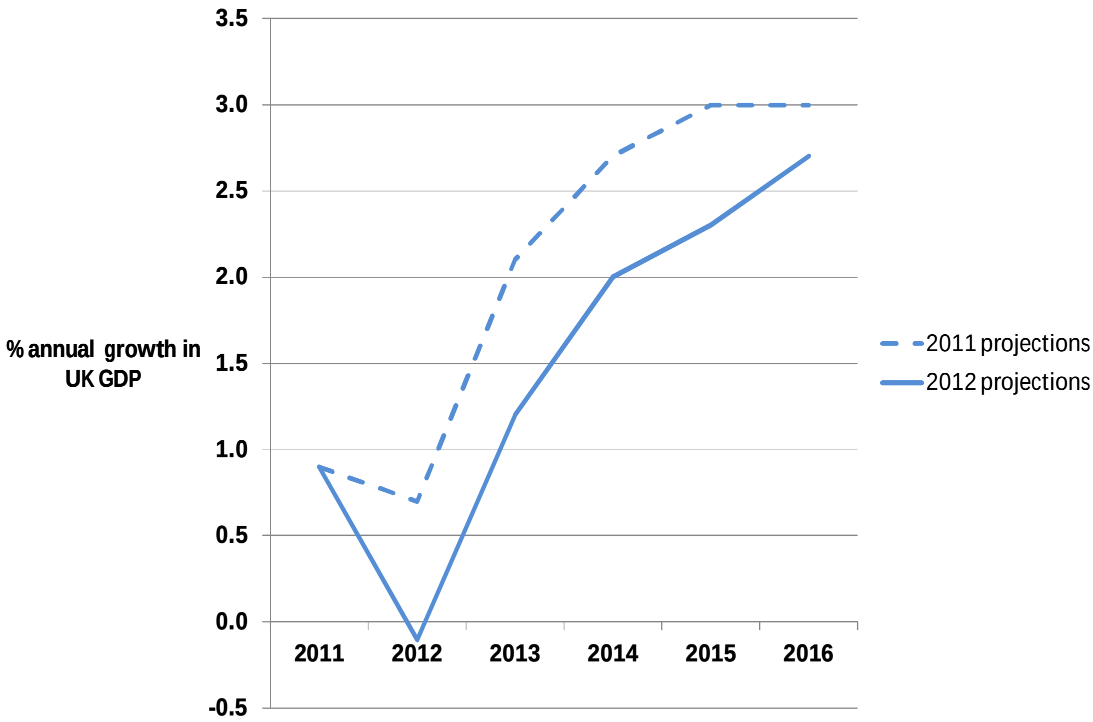
The first part was to check that we were using the latest data. We found that some of the sources (such as the Office for Budget Responsibility (OBR)) have updated their projections, and we have used the latest data available. A complete list is in Annex A.

There were three issues. In descending order of impact, they were: economic growth projections, energy prices and the North West Regional Development Agency (NWRDA).

OBR economic projections

The major issue relates to changes in the economic projections from OBR. These are noticeably lower than the previous forecasts which we used for our original work. To illustrate this, we compare the OBR's November 2011 forecasts of GDP to their most recent forecasts, in Figure 2.2 below.

Figure 2.2: Comparison of OBR 2011 and 2012 forecasts of GDP growth (central case)



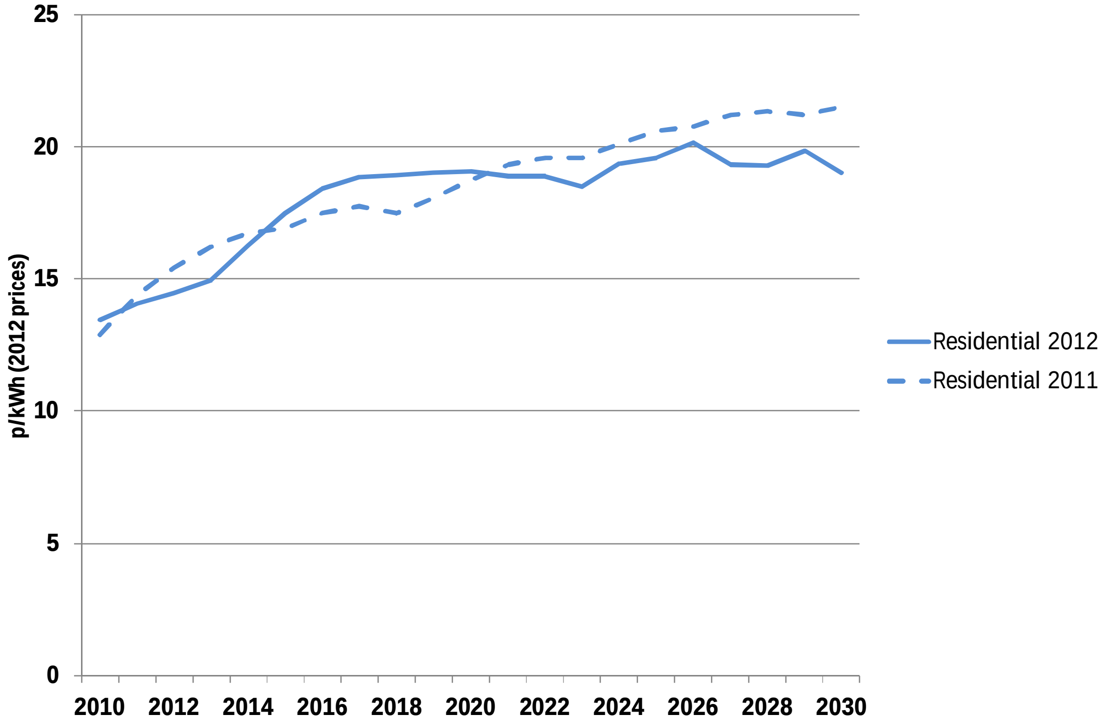
As this shows, the new projections (solid line) are well below previous projections (dashed line), out to 2016. As GDP[3] is the major driver for commercial and industrial demand in our model, this has the effect of depressing our results compared to the previous ones. On the other hand, there is some positive economic news, such as the fact that the number of people in employment is at the highest level since records began in 1971[4]. Increasing employment will tend to increase household incomes, which our model suggests is a key driver of domestic electricity demand.

[3] Or GVA for the North West.
[4] Source: Financial Times, 12 December 2012, based on ONS Labour Market Statistical Bulletin

DECC prices

The second issue is that DECC has changed its projections of future electricity prices. The projections now have quite a different shape, and this can make the figures for changes by 2014/15 and by 2022/23 look misleadingly different to those from our previous work. As an illustration, Figure 2.3 below shows the differences in DECC's forecasts for retail residential prices (central case) from both 2011 and 2012.

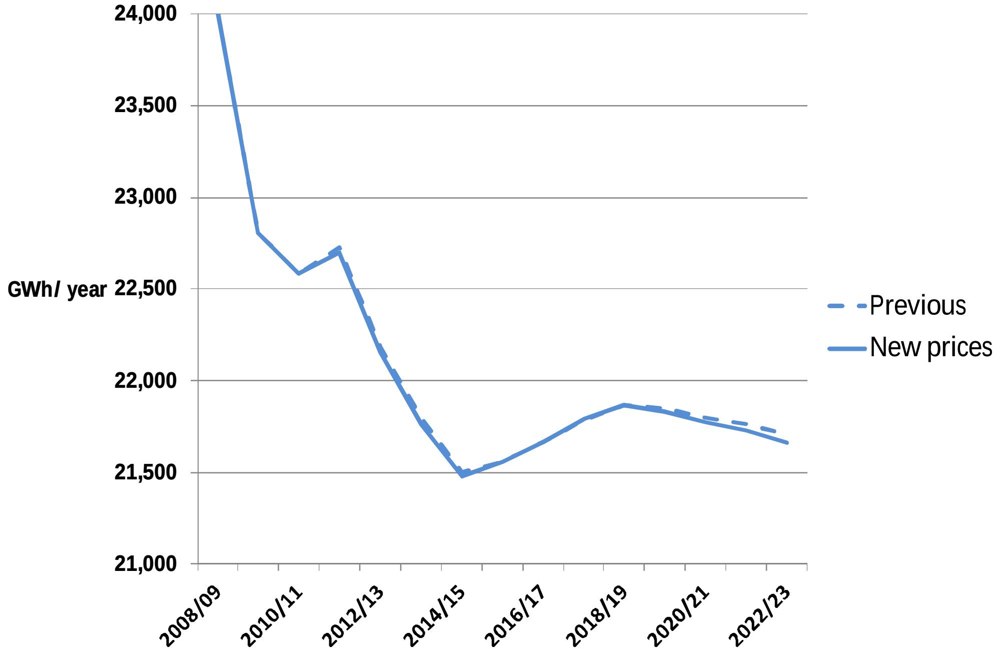
Figure 2.3: DECC price projections



As this shows, prices are higher in say 2016, but lower by 2022. This can make comparing figures for price changes over time misleading.

However, the overall impact on the results is minimal, as Figure 2.4 shows.

Figure 2.4: Changes to results in Green Recovery scenario due to new DECC electricity price forecasts



The figure shows our previous results for annual demand[5], and then a new set of projections using the new DECC prices (and no other changes).

NWRDA

The first issue arose because some of our data was sourced from the NWRDA. This was abolished in July[6] and no updates to the previous data have been published. We have used the existing data, even though it is now over a year old, since we are not aware of any other economic forecasts specifically for the North West.

2.3.2. Figures to 2030/31

The second part of our work was to source inputs for the period 2023/24 to 2030/31. In some cases (such as the ONS figure or DECC price projections) the data sources give us figures to 2030/31 directly. In other cases, we have assumed a continuation of the trend for 2022/23.

In most cases, the trend is a straight line. However, the DECC electricity price forecasts show a slight dip in the mid 2020s, and this leads to our results having a similar dip. We asked DECC what the basis for this is, and they responded that the dip is "*mainly due to an oscillation in policy costs on consumers*". They also note that "*...there's great uncertainty about when/if such fluctuations might occur*" and they consider that it is "*...probably best to focus on the long run trends rather than specific yearly movements*".

[5] "Green Recovery" scenario only. The results for other scenarios would be similar.

[6] Source: Department for Business Innovation and Skills

2.3.3. Review of previous assumptions

Finally, we had an independent review of our assumptions (as opposed to sourced input data). This found no significant issues.

2.4. Adjustments for change in base year

In our previous results, the figures were presented with a base year of 2010/11. For the new results, the base year is 2011/12. We therefore had to adjust some of our assumptions to reflect this.

For example, our assumptions on energy efficiency from the previous report were for the impact from 2010/11 to 2014/15 and 2022/23. We had previously assumed a linear energy efficiency trend, so have simply assumed that the reduction between 2011/12 and 2014/15 is three quarters of that from 2010/11 to 2014/15. The reduction from 2010/12 to 2022/23 has been similarly reduced.

2.5. Produce draft results

The next stage was to combine the revised model and input assumptions to produce new draft results. These are shown in section 4. There were no particular issues with doing so.

2.6. Review results with ENWL

We presented our draft results to ENWL at a meeting in their offices on 13 December. Following that meeting, we made a number of changes to this report, largely to include additional information about the scenarios. This information is in Annex B.

2.7. Re-run model and produce final report

Our revised model results are shown in Section 4. We will also provide completed input spreadsheets showing the results by local authority. In this report we have focused on bringing out the key messages and so only present the overall results for the ENWL region. We expect that the results for each local authority will follow a similar pattern to those for the previous results, in terms of how each local authority compares to the average for the region as a whole. <u>In the presentation on 13 December, we noted the risks associated with placing too much emphasis on figures for individual local authorities, particularly more than a few years into the future</u>.

3. MODEL CHANGES

In this section we describe the changes we have made to the ENWL models as a result of new data.

We received new data from ENWL, consisting of actual customer numbers for December 2011. We also updated our figures from the ONS and OBR.

To determine the new models, we ran a regression on the new figures, using the same form of the model as before. That is, we assumed that the factors driving future electricity demand are the same as in our previous models, but that the relative importance of the factors might change slightly, based on the new historic data. The model equations, and an explanation of how we came to choose the factors we did, are in Annex C. An explanation of how we forecast those factors is in Annex D. In summary, the statistical analysis we did in our previous work showed that the most significant factors ("exogenous variables") are income and price for households, and price and GVA for other consumers.

Table 3.1 below compares the co-efficients[7] for the new and previous domestic models. Note that the results in the tables relate to the entire ENWL area.

Table 3.1: Domestic model co-efficients (standard errors in brackets)

Variable	Previous model	New model	Increase / (decrease)
Constant	-2.88 (0.29)	-3.16 (0.38)	-0.28
Income	0.41 (0.02)	0.42 (0.03)	0.01
Price	-0.14 (0.02)	-0.17 (0.03)	-0.03
2005 Dummy	0.03 (0.01)	0.04 (0.02)	0.01
2008 Dummy	0.06 (0.01)	0.07 (0.02)	0.01

As can be seen, the model is very similar to the previous one. While the impact of a change in price or a change in income is slightly higher than before, the differences are relatively small.

Table 3.2 does the same for the models of non-domestic electricity demand.

Table 3.2: Non-domestic model co-efficients (standard errors in brackets)

Variable	Previous model	New model	Increase / (decrease)
Constant	4.21 (0.43)	4.39 (0.56)	0.18
Electricity Price	-0.11 (0.02)	-0.13 (0.02)	-0.02

[7] Note that our model looks at the relationships between the *log* of demand and the *log* of price and income.

Variable	Previous model	New model	Increase / (decrease)
GVA	0.49 (0.04)	0.48 (0.05)	-0.01

As this shows, the new model is virtually identical to the previous one. It suggests that there is a slightly higher fixed component of demand, and that electricity price is slightly more significant (relative to GVA) than before. However, the differences are small and within one standard error of the previous model. It would therefore be wrong to attach great significance to these changes.

In summary, there is little significant difference between the new models and the previous ones. This is as might be expected, since they are based on a single additional year of data. The major changes to our results (shown in the next section) are because of changes to data rather than changes to the model. There is one effect of the increased sensitivity to prices. As the next section shows, the results in all scenarios are lower. This drop is larger in scenarios based on high prices, because of the increased price sensitivity.

4. INITIAL RESULTS

This section presents our initial high-level results, for the ENWL region as a whole. For our final results, we will also present the figures for each local authority.

4.1. Scenarios considered

As for our previous analysis, we ran five scenarios. These are illustrated in Figure 4.1 below; more detail is presented in Annex B. To make it easier to discuss the scenarios, we have given them descriptive names, as Figure 4.1 shows.

Figure 4.1: Scenarios considered

		ECONOMIC GROWTH		
		LOW	CENTRAL	HIGH
ENERGY EFFICIENCY	HIGH	Nothing but Green		Green Recovery
	CENTRAL	Stalled Economy	CENTRAL CASE	
	LOW			Strong Growth

The differences between the scenarios are shown in Table 4.1 below. A more detailed explanation of the factors we considered and how we derived them is in Annex D.

Table 4.1: Assumptions underlying each scenario

Scenario	Economic factors	Energy efficiency factors
Central Scenario	• Central economic growth • Central price growth	• Central energy efficiency • Central peak load change
Strong Growth	• Relatively high economic growth • Central price growth	• Relatively low energy efficiency • Low peak load change
Stalled Economy	• Relatively low economic growth • Low price growth	• Central energy efficiency • Central peak load change
Green Recovery	• Relatively high economic growth • High prices	• High energy efficiency • Central peak load change

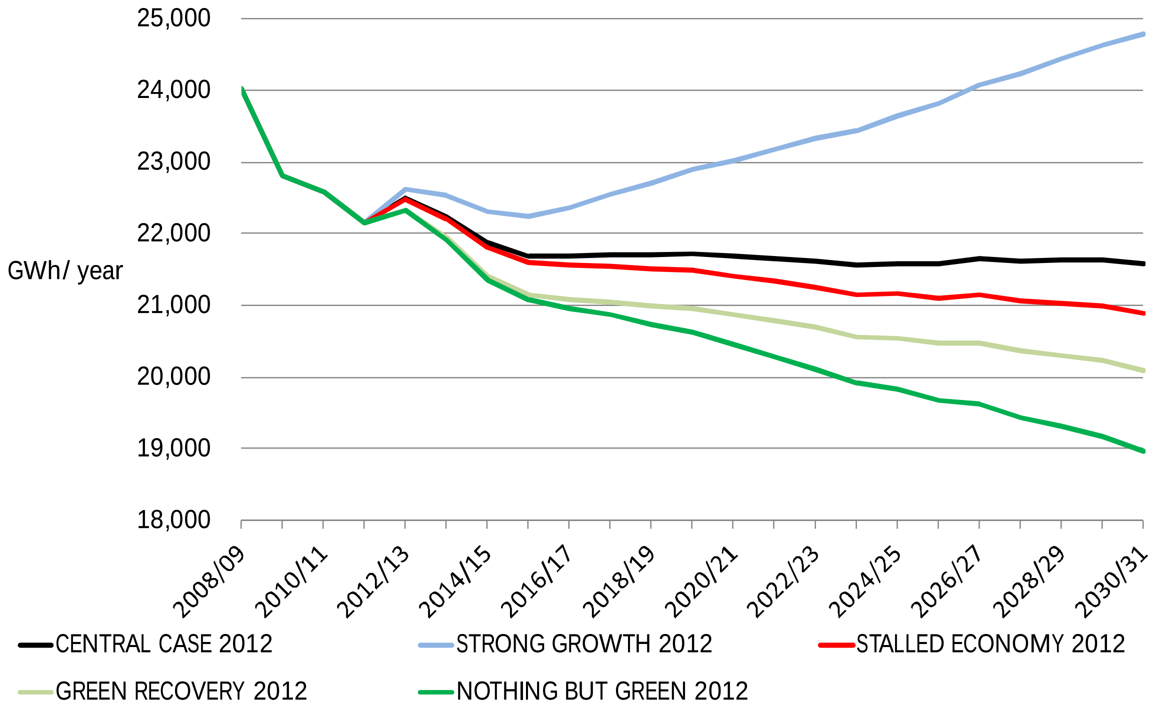
Scenario	Economic factors	Energy efficiency factors
Nothing but Green	• Relatively low economic growth • Central case price growth	• High energy efficiency • High peak load change

The main results for each scenario are shown below. Detailed results for each local authority will be provided in the outputs spreadsheet[8].

4.2. Overall annual demand to 2030/31

Figure 4.2 shows the overall annual demand results for each scenario.

Figure 4.2: Total annual demand to 2030/31, all scenarios



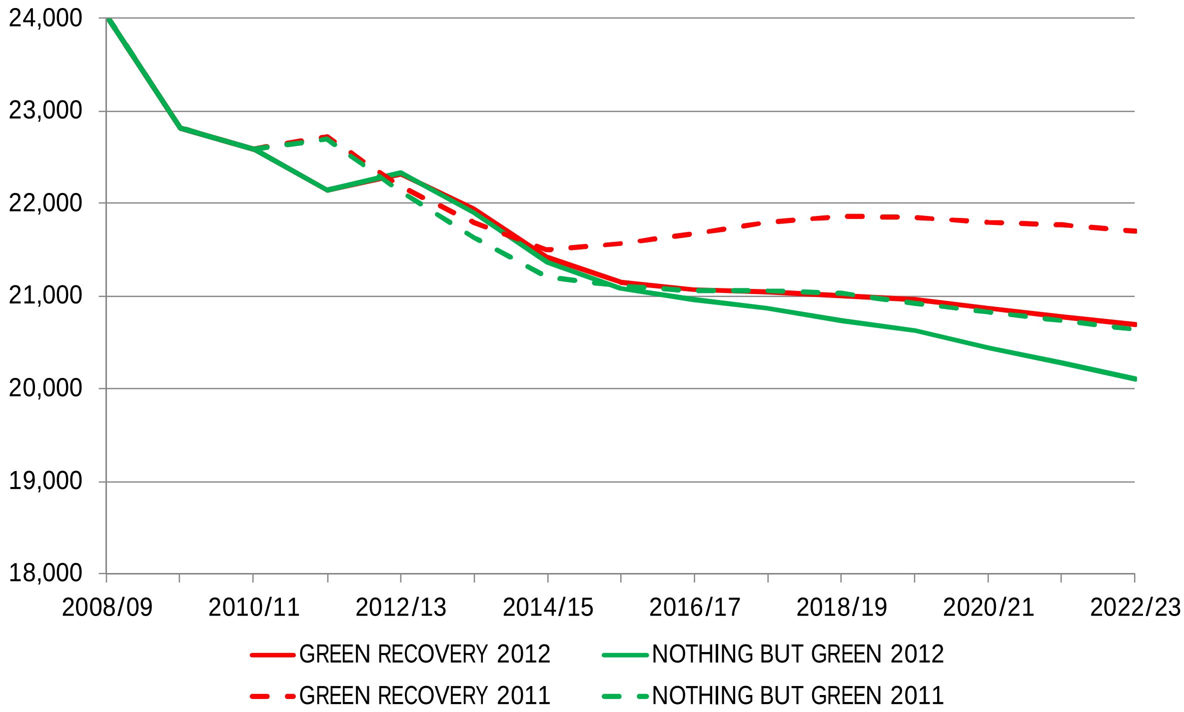
In summary, we see falling demand in the "green" scenarios, driven by higher prices and greater energy efficiency. In the "stalled economy" and "central" scenarios, demand is more or less flat to 2030. Only in the "strong growth" scenario do we see constantly rising demand, although it does not return to 2008 levels until well into the 2020s.

4.2.1. Comparison with previous results

We also present a comparison of our results to those from our previous work (note that that only included projections to 2022/23). Figure 4.3 compares the two "Green Scenarios". Current results are shown as solid lines, and the previous results are shown as dashed lines.

[8] *As emailed by Dr Victor Levi to Iain Morrow, 7 December 2012*

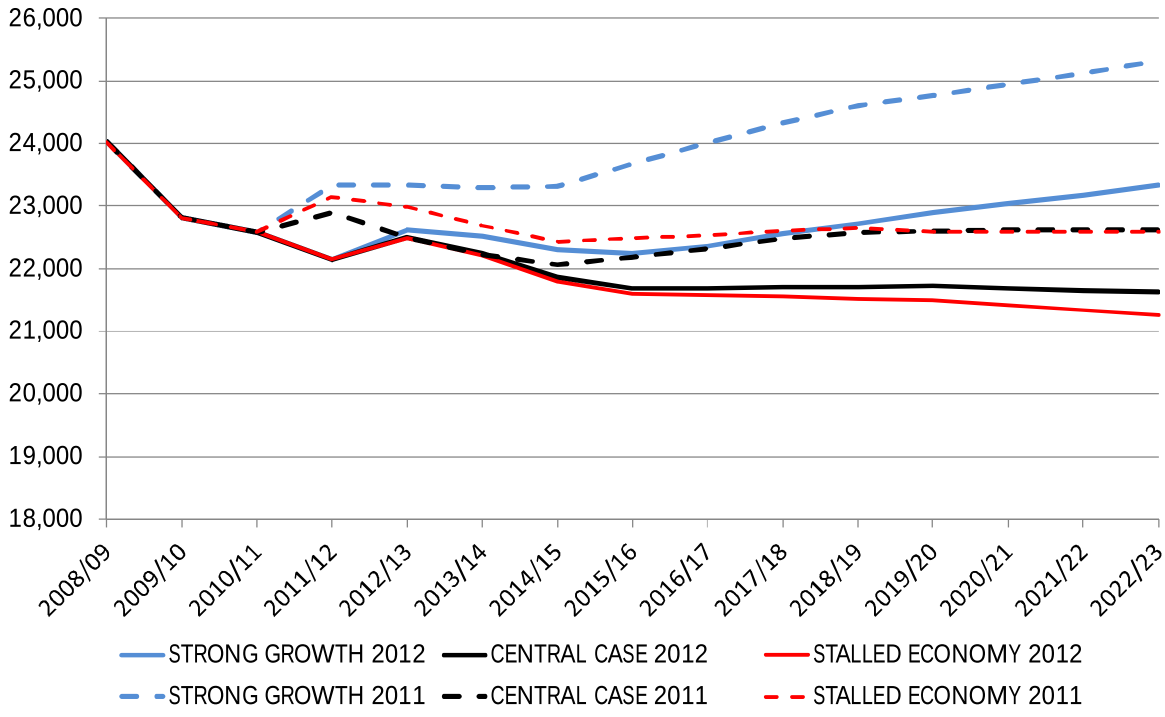
Figure 4.3: Comparison of current and previous "Green" scenarios



The figure shows that our current projections are significantly below our previous ones for both scenarios, with the differences widening over time. The difference is particularly marked in the "Green Recovery" scenario, because of our model's now greater sensitivity to high prices. These prices are used for the "Green Recovery" scenario but not the "Nothing but Green" scenario, as Table 4.1 above shows.

Figure 4.4 compares the "Strong Growth", "Stalled Economy" and "Central Case" scenarios.

Figure 4.4: Comparison of current and previous Strong Growth and Stalled Economy scenarios



Again, the projections are lower in all cases. The difference is particularly pronounced for the "Strong Growth" scenario, because it assumes higher prices than the low prices assumed in the "Stalled Economy" scenario.

In summary, all the projections are lower, mainly because of lower projections of future economic growth (see Figure 2.2). There is also a slight reduction in new domestic connections and in household income growth. These are driven from the ONS's forecasts of household growth, and the OBR's forecasts of income growth. Both forecasts are lower than last year's.

4.3. Longer-term projections

In developing our longer term projections, we have considered what changes there might be in the factors driving electricity supply and demand in the 2020s. Some of these cannot be fully captured in a quantitative analysis, and so we briefly discuss them here.

Our main conclusion is that there is a great deal of uncertainty, and it is difficult to point to definite trends within the period. Policy and trends are relatively well-defined to 2020, but the picture thereafter is much less clearly defined. In general, where policies for the 2020s are set out at all, they are seen to be continuations of policies in the 2010s[9].

For this reason, we have assumed that the factors driving electricity demand continue on the same trend beyond 2022/23 and on to 2030/31. This gives us a relatively wide range of possible outcomes by 2030/31.

[9] See for example the recent analysis by Arup: http://www.arup.com/Publications/UK_Energy_Legislation_Timeline.aspx

In many ways, this is as expected. Projecting nearly twenty years into the future in a complex area such as energy demand is extremely difficult. There are possible developments on the horizon which could push demand very high. One in particular would be an abundance of cheap shale gas. Greater interconnection of global gas markets could also change the future profile of prices. Conversely, there are potential developments that could push demand very low (for example, the widespread roll-out of highly efficient lighting).

We discuss some of these qualitatively below. We have divided the factors that might affect demand into four categories: the nature of demand, policy, industrial development and price effects.

The first category is changes in the nature of consumer demand. These could include an increasing use of appliances with high electricity demands, such as IT equipment or home entertainment systems. Of course, these are likely to be dwarfed by the demands from electric vehicles and heat pumps, if those technologies are taken up in large numbers[10]. Changes in consumer demand are, on past trends, only likely to increase total electricity demand. This is before taking account of changes such as efficiency standards, which are discussed below.

The second change relates to policy changes. These can be about product efficiency standards, requirements to deploy smart meters or other new technologies, or about other energy efficiency standards, such as home insulation.

Product efficiency standards of course only ever go in one direction – towards lower consumption per unit of output. The question is about how fast standards will be driven. In our work, we have assumed that the expected rate for the 2010s continues into the 2020s. Factors that could mean that this is not valid include technical limitations on efficiency or diminishing returns. Efficiency might, for example, become increasingly expensive per watt, and there might be a move to look at other sources of demand reduction than appliances. For the moment, however, we see no reason to assume either of these.

Industrial development is a factor that could affect the level of non-domestic demand in particular. Put simply, some industries are more electricity-intensive than others, and a shift towards or away from these could make significant changes to electricity demand.

Price is another factor likely to affect future demand. In a scenario where energy is relatively cheap in the 2020s, perhaps because of abundant unconventional or shale gas, electricity prices are likely to be relatively low. Our analysis suggests that price is a significant driver (although not as significant as household income or GVA). Therefore, in a world of low prices, demand is likely to be noticeably higher. Conversely, if prices rise at a faster rate than we expect, demand could be further suppressed.

[10] Heat pumps and electric vehicles are specifically excluded from our terms of reference.

5. CONCLUSIONS

Our key conclusion from this piece of work is that in most scenarios, electricity demand remains low in the North West over the next few years. Based on our econometric analysis, the strongest driver of this low demand in the non-domestic sector is the projected low levels of economic growth. For the domestic sector, the strongest driver is the projected slow growth in incomes, but again much of this can be traced back to low projections of economic growth.

The projected growth in electricity prices is also a contributing factor. In the “high” case, DECC’s projections show growth of nearly 80% by 2022/23, and even in the “central” case the increase is nearly 60% (both figures are for non-domestic prices). Continuing improvements in energy efficiency will also have an effect, although as noted in our previous report many of these relate to heating and so to gas rather than electricity.

That said, there is a significant range of possible outcomes, and in a world where economic growth returns and prices are low (perhaps because of shale gas), demand might grow significantly. Our analysis also takes no account of heat pumps or electric vehicles.

Annex A: Data sources

Table A.1 shows the data sources we have used, and how they have been updated if required.

Table A.1: Data sources used

Data	Source	How updated?
Customer numbers	ENWL	Using Dec 2011 actuals rather than Dec 2010
Historic electricity consumption figures	ENWL	Provides updated values for 2010/11 and 2011/12; data in terms of kWh consumed; as sent on 22 November 2012
Peak demand data	ENWL	Sent on the 22nd of November, 2012; includes data from January 2012.
Data on large EHV customers	ENWL	Includes figures for 2011/12. Sent on the 22nd of November, 2012.
Employed individuals and labour force	ONS Nomis	Updated data from 7 Dec 2012. Data applies up to end-2011.
Public v private employment shares	ONS Nomis	Updated data from 7 Dec 2012. Data applies up to end-2011.
Public employment projections	OBR and ONS Nomis	Updated data from 7 Dec 2012.
Private employment projections	OBR, NW RDA analysis and ONS Nomis	Updated data from 7 Dec 2012.
Total employment projections	OBR, NW RDA analysis and ONS Nomis	Based upon public and private employment projections.
Labour force participation	ONS Nomis	Updated data from 9 Dec 2012. Data applies up to end-2011.
Working age participation	ONS Nomis	Updated data from 9 Dec 2012. Includes projections out to 2030.
Productivity	OBR	Data updated to include OBR Economic and Fiscal Outlook from Dec 2012.
GVA by LA	OBR and ONS Nomis	Based upon projections of total employment and productivity.
Household income projections	OBR and ONS Nomis	Data updated for 11 Dec 2012. Includes total employment projections.
Household income by LA	OBR and ONS Nomis	Based on household income projections, and total employment projections.
Electricity price forecasts	DECC	DECC Updated Energy & Emissions Projections - October 2012
Historical electricity price information	DECC	Annual prices of fuels purchased by manufacturing industry (p/kWh) (QEP 3.1.4), Tables last updated 27 September 2012

ANNEX B: DESCRIPTIONS OF SCENARIOS

In this annex we include a brief narrative description of the scenarios we have considered. They are as shown in Figure B.1 below.

Figure B.1: Scenarios

		ECONOMIC GROWTH		
		LOW	CENTRAL	HIGH
ENERGY EFFICIENCY	HIGH	Nothing but Green		Green Recovery
	CENTRAL	Stalled Economy	**CENTRAL CASE**	
	LOW			Strong Growth

Nothing but Green

This is our scenario for the North West going green without strong economic growth ("Nothing but Green"). It assumes that economic growth continues at a relatively low level. Price remains in line with our central projections as we do not consider there will be sufficient pressure from lower growth for any significant price falls. Energy efficiency savings, however, are relatively high. This results from a continued effort by businesses and consumers to reduce electricity usage, as well as the high growth in prices relative to income. We also expect in this scenario a greater reduction in peak demand in addition to the other changes resulting from the efficiency savings and economic factors.

A summary of our assumptions for this scenario is shown in Table B.1 below.

Table B.1: Nothing but Green – Key assumptions for changes in the factors, from 2011/12

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Domestic			
Number of household	2.5%	9.5%	15.2%
Household income	-1.4%	9.6%	25.0%
Price	16.8%	32.6%	34.2%
Energy efficiency	-7.6%	-17.0%	-27.0%

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Peak demand	-2.2%	-8.8%	-15.4%
Non-domestic			
GVA	1.3%	14.9%	31.8%
Price	31.7%	58.2%	61.0%
Energy efficiency	-9.1%	-19.4%	-30.4%
Peak demand	-0.5%	-2.0%	-3.5%

Green Recovery

This is our scenario for strong economic growth coupled with strong energy efficiency savings. High UK economic growth is driven by a global recovery, which results in high employment, but also pushes up electricity prices (through higher commodity prices). As economic growth is driven by higher employment rather than labour productivity growth, household income growth is driven by additional occupants being employed rather than real income growth. Electricity prices will be relatively high and will push business and households towards relatively high energy efficiency savings. Again, impact on peak demand alone is in line with our central estimates.

A summary of our assumptions for this scenario is shown in Table B.2 below.

Table B.2: Green Recovery – Key assumptions for changes in the factors, from 2011/12

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Domestic			
Number of households	2.5%	9.5%	15.2%
Household income	-1.8%	11.7%	30.4%
Price	26.2%	47.0%	50.2%
Energy efficiency	-6.2%	-14.9%	-24.3%
Peak demand	-0.5%	-2.0%	-3.5%
Non-domestic			
GVA	2.1%	24.3%	52.3%
Price	40.6%	78.2%	82.2%
Energy efficiency	-8.7%	-18.0%	-29.4%
Peak demand	0.0%	0.0%	0.0%

Stalled Economy

In this scenario we assume that the global downturn lasts longer than anticipated and the North West is stuck in an aggregate demand trap. This affects the UK through lower growth. On the positive side, low global demand keeps commodity prices relatively low and therefore price growth is relatively low. As the low economic growth is offset by low prices we do not consider there will be additional pressure for efficiency savings over our central projection. Peak demand will therefore also be in line with our central projections.

A summary of our assumptions for this scenario is shown in Table B.3 below.

Table B.3: Stalled Economy – Key assumptions for changes in the factors, from 2011/12

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Domestic			
Number of household	2.5%	9.5%	15.2%
Household income	-1.4%	9.6%	25.0%
Price	5.5%	16.1%	17.4%
Energy efficiency	-7.9%	-16.2%	-24.6%
Peak demand	-0.5%	-2.0%	-3.5%
Non-domestic			
GVA	1.3%	14.9%	31.8%
Price	10.2%	33.7%	38.1%
Energy efficiency	-8.8%	-14.7%	-21.9%
Peak demand	0.0%	0.0%	0.0%

Strong Growth

In this scenario we consider that the UK is able to achieve relatively high economic growth, through high employment. As noted in the main body of this report, UK employment is already growing, and is now at the highest level in absolute terms since records began.

Electricity price growth remains in line with DECC's central forecasts. However, as economic growth is driven by higher employment rather than labour productivity growth, household income growth is driven by additional occupants being employed rather than real income growth. The strong economic growth coupled with relatively stable price growth, puts less pressure on households and businesses to achieve energy efficiency savings. Therefore, in this scenario energy efficiency savings are on the low side and we also expect that peak loading reduction is on the low side.

A summary of our assumptions for this scenario is shown in Table B.4 below.

Table B.4: Strong Growth – Key assumptions for changes in the factors, from 2011/12

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Domestic			
Number of household	2.5%	9.5%	15.2%
Household income	-1.8%	12.8%	35.4%
Price	16.8%	32.6%	34.2%
Energy efficiency	-1.9%	-3.4%	-5.4%
Peak demand	0.0%	0.0%	0.0%
Non-domestic			
GVA	2.1%	24.3%	52.3%
Price	31.7%	58.2%	61.0%

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Energy efficiency	-4.7%	-8.8%	-14.4%
Peak demand	0.0%	0.0%	0.0%

Central Case

Finally we present the results for our central case. In this scenario, we use central or base case values for all assumptions.

A summary of our assumptions for this scenario is shown in Table B.5 below.

Table B.5: Central Case – Key assumptions for changes in the factors, from 2011/12

	2011/12 to 2014/15	2011/12 to 2022/23	2011/12 to 2030/31
Domestic			
Number of households	2.5%	9.5%	15.2%
Household income	-1.5%	11.1%	29.7%
Price	16.8%	32.6%	34.2%
Energy efficiency	-6.0%	-13.5%	-21.5%
Peak demand	-0.5%	-2.0%	-3.5%
Non-domestic			
GVA	1.6%	19.0%	40.6%
Price	31.7%	58.2%	61.0%
Energy efficiency	-6.1%	-12.2%	-19.8%
Peak demand	0.0%	0.0%	0.0%

ANNEX C: ECONOMIC MODEL – EQUATIONS

This annex shows the key equations in the economic models we used for our previous work for ENWL. They are taken directly from our previous report.

Equation C.1: Model of domestic electricity consumption

$$DEC_t = \beta 0 \quad + \beta_I I_t + \beta_{PD} PD_{t-1} + \beta_{2005} D_{2005} + \beta_{2008} D_{2008} + \varepsilon_i$$

In this equation:

- DEC_t represents (the log of) domestic electricity consumption per household in year t;
- I_t represents (the log of) income per household in year t;
- PD_{t-1} represents (the log of) retail electricity prices (lagged by one year) in year t;
- D_{2005} represents the dummy variable for 2005;
- D_{2008} represents the dummy variable for 2008;[11]
- β_i are the co-efficients; and
- ε_i are the error terms.

Using this model, we ran multiple ordinary least squares linear regression analyses, testing for the relative significance of each variable with respect to domestic energy consumption in the North West. We also ran the same model using both North East data and national data in order to determine if the North West findings were consistent in the area and on a national scale. We found our results to be roughly consistent with the national findings, but very different from those of the North East. Additionally, we tested for the impact of gas prices on domestic electricity consumption but found that the related variable skewed our results and rendered our model less efficient.

All of the linear regression tests that we ran included both robustness tests to determine whether or not there was heteroskedasticity in the model and an analysis of correlation matrices in order to mitigate any multicollinearity.

We now present the corresponding model for non-domestic electricity consumption, in Equation C.2 below.

Equation C.2: Model of non-domestic electricity consumption

$$NDEC_t = \beta_0 + \beta_{PC} PC_{t-1} + \beta_V V_t + \varepsilon_i$$

In this equation:

- $NDEC_t$ represents (the log of) non-domestic electricity consumption in year t;

[11] With the exception of the dummy variables, all variables included in the model were in logarithmic form. We consider that the logarithmic form better reflects the consumption decisions of domestic users and the impact of the variables in their decisions.

- PC_{t-1} represents (the log of) non-domestic electricity prices (lagged by one year) in year t;
- V_t represents (the log of) North West GVA in year t;
- β_i are the co-efficients; and
- ε_i are the error terms.

We ran this linear regression model using ordinary least squares. We tested for heteroskedasticity, multicollinearity and autocorrelation, using a combination of correlation matrices, robustness and error tests. The linear regression results produced a very low Durbin Watson statistic, which led us to consider whether or not the model might be faulted by serial correlation. In order to examine this further, we ran a correction for autocorrelation followed by a Cochrane-Orcutt AR(1) regression. This second regression analysis produced very weak results. After a review of econometric literature, we believe that the original linear regression model provides the most accurate results and the best fit for the data. While a very low Durbin Watson statistic may be indicative of serial correlation, it is also true that with relatively small data samples, Durbin Watson statistics are not always accurate. Moreover, if serial correlation does exist in the model, the OLS regression will still be unbiased, albeit highly inefficient. According to Meetamehra, a common issue among electricity consumption forecasts models is the assumption that "*fuel prices are determined independently of both total energy consumption and the distribution of consumption by fuels.*" In other words, the assumption indicates a "*failure to recognise the interdependence between prices and quantity*", which can lead to inefficiencies in the model (Meetamehra, 2002).

Other factors considered and rejected

In an ideal world data would be available for every variable that is considered to drive electricity consumption. In theory, this would ensure that the model would be able to better predict electricity consumption. However, consistent and accurate data is not always available for all variables that you may wish to include. In addition, when using the model to forecast future consumption the more variables you include, the more forecasts are required (for each of these variables) and this will add to the uncertainty of the model. Given these points, if a parsimonious model can be developed with a high goodness-of-fit this may be preferable to a model with a slightly higher goodness-of-fit but which requires additional variables to be forecasted.

Below we discuss a number of variables that we considered for our model, and the reasons why we concluded not to include them:

Weather

Variance in the weather from year-to-year can affect household consumption of electricity; a particularly cold year can increase the demand for electricity (although this is to a lesser extent in GB than other countries given the main source of heating is gas). If one wanted to examine daily electricity consumption, a temperature variable would be required. However, on an annual basis producing a usable measure to account for weather patterns is difficult, as an average daily temperature for a year is not necessary meaningful in relation to consumption. In addition, forecasting the weather is notoriously difficult to achieve. Given these arguments we have excluded weather from our model.

Income demographics

There is a positive correlation between income and electricity consumption. An area where the model could be improved is with regards to its ability to account for the impact of demographic changes. Including a breakdown of, for example, low, medium and high income households in the North West could improve the model's predictive power. If the stock of households grew at different rates for each of these categories then this would likely affect demand. However, in order for this to improve our model's ability to predict consumption we would need forecasts for income demographics out to 2022/23.

Occupants per household

Data on the average annual occupants per household is available from ONS. The number of occupants in a household is likely to effect the consumption of the household (i.e. the more occupants, the greater the electricity consumption). We have analysed the available data and it can be seen that the average number of occupants per household has been falling over time – from 2.48 in 1990/91 to 2.28 in 2010/11. We included this variable in our model and found that it was not significant. In addition, we found a slight increase in electricity use per household between 1990 and 2011. This is supported by Ofgem's findings[12] in which they conclude that average household electricity consumption did not decrease between 2003 and 2011. Given the lack of significance in our model and the lack of anecdotal support for its impact on electricity demand, we have excluded this variable from our model.

Gas prices

It is a generally accepted principle that the demand for a good will be affected by the price of a substitute good(s). Gas can be considered as a substitute for space and water heating, in particular, which would indicate that it is a potential explanatory variable in our model. However, when we included a gas price variable in our model it was not significant and in fact led to multicollinearity in the model. We have concluded that the difference between gas and electricity prices (where gas per unit equivalent energy prices are much lower than those of electricity) and the cost of the capital investment to switch fuel sources, means that electricity is not yet considered as a substitute heating source for many households.

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12 Ofgem (2011), *Typical Domestic Energy Consumption Figures.* Accessed at: http://www.ofgem.gov.uk/Media/FactSheets/Documents1/domestic%20energy%20consump%20fig%20FS.pdf

ANNEX D: DEFINITION AND DEVELOPMENT OF THE FORECAST VARIABLES

The ToRs set out that ENWL require economic forecasts to be provided for GVA growth and household income. In this annex we set out our approach to developing the baseline GVA forecasts, discuss the evidence that we have considered in developing the forecasts and then summarise the results. Given the level of uncertainty surrounding growth forecasts over the period 2011/12 – 2022/23, we have also developed GVA scenarios, which we discuss at the end of this section. Next, this annex will set out the approach and results that we have used to develop the household income and household formation growth assumptions. Before either of these components however, we will first present definitions of the key variables under consideration.

D.1. Definition of the forecast variables

GVA

GVA is a measure of the goods and services produced by a sector, industry or region of an economy. In National Accounting terms it is equal to total output (i.e. the total value of sales) minus intermediate consumption (i.e. the cost of inputs used in production).[13]

GVA is linked to the GDP measure of output; it is equal to GDP – taxes + subsidies. As taxes and subsidies are available on aggregate at the national level, GVA is used to estimate regional growth.

The measurement of GVA can carried out using either the income or production approach. The production approach involves measuring the value of output of goods and services produced and removing the value of inputs used in the production process. While the income approach is based on measuring the incomes earned by resident individuals and corporations in the production of the goods and services, excluding transfer payments (e.g. state benefits). As data is more readily available on incomes, the GVA income measure is the most commonly used measure of regional GVA.

The main determinants of income based GVA are the incomes of employees (which is a function of the total number in employment and the average wages) and the profits made by corporations (defined by the ONS as gross operating surplus).

In economic terms GVA growth is therefore driven mainly by changes in employment (the total number in employment) and productivity (which will be a key driver for both employees' wages and employers' profits).

Real Household Income Growth

Household income is simply defined as the combined income from all sources (can include labour income, pension and benefits, income from investments and savings) for all adult members of a household. The biggest sources of household income are labour income and income from pension and benefits. The real growth in household income is the year on year growth in income adjusted for inflation.

[13] ONS Regional Accounts methodology guide.

D.2. Baseline GVA forecasts by LA

In Section 2.1 of our previous report, we describe our approach to developing the baseline GVA forecasts. Here, we discuss the evidence that we have considered to develop these forecasts and then summarise the results. Given the level of uncertainty surrounding growth forecasts over the period 2011/12 to 2022/23, we have also developed GVA scenarios, which we discuss at the end of this section.

The baseline GVA forecasts are broken down into the following three components:

- public sector employment growth;
- private sector employment growth; and
- productivity growth.

Below we summarise our forecasts for each of these components.

D2.1. Public sector employment growth

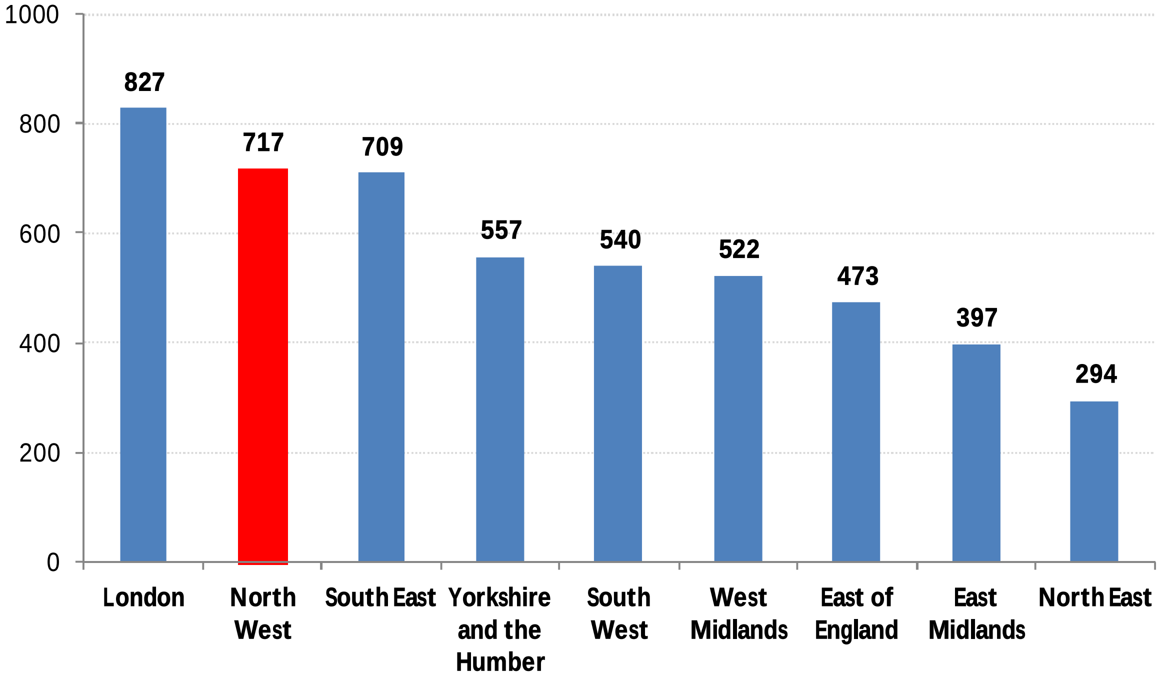
To develop the public sector employment growth forecasts we have considered:

- the current level of public sector employment in the ENWL LAs;
- the OBR's updated public sector employment projections for 2011/12 to 2016/17 as published in the November Economic and Fiscal Outlook;
- the GAD long-term public sector employment projections 2017/18 to 2022/23 (which are the same assumptions used in the OBR's long-term fiscal analysis); and
- the extent to which evidence exists to suggest that there is a material difference in the composition of public sector employment in the ENWL LAs compared to the rest of England. This helps us to understand the vulnerability of the region to public sector job cuts, and also if the region will potentially see a materially different trend in public sector jobs to the OBR forecasts.

Public sector employment in the ENWL LAs

We have reviewed data on the total public sector employment numbers by Local Authority, so we can analyse the exposure of each of ENWL's LAs to the public sector job cuts. Figure D.1 shows that the North West is the second biggest employer of public sector employees in England, employing 717,000.

Figure D.1: Total public sector employment 2010 (000's)[14]



However, this is in part because the North West is one of the biggest regions in the country in employment terms; therefore, it is also worthwhile to consider the proportion of the workforce in public sector employment. Overall, in 2010/11 22.4% of the those in employment in the ENWL region were public sector workers, this is marginally lower than the proportion for the North West – 22.8%, but higher than average across England – 21%.

Our analysis suggests that the ENWL region as a whole is highly exposed to the spending cuts in terms of the total number of job losses, but in percentage of employment terms is broadly similar to the rest of England.

OBR Forecasts

The OBR provide an analysis of the implications of the Government's spending cuts on public sector employment. Following the Chancellor's Autumn Statement, the OBR produced updated forecasts, which are published in the Economic and Fiscal Outlook 2011. In these updated forecasts the OBR revised their initial assessment of the level of public sector job cuts that might take place as a result of the Government's planned fiscal consolidation. The OBR now estimate that there will be a **total of 710,000 job cuts across the country by 2016/17 if the Government achieves its fiscal targets** (this was revised up from the 400,000 estimate published by the OBR in March 2011). The OBR analysis currently estimates that public sector employment will fall by 2.2% on average each year until 2016/17, which equates to a reduction of approximately 12% in the total size of the public sector workforce over that time period.

Over the longer-term the GAD public sector employment projections assume that public sector employment growth will average 0.25% each year until 2022/23. The GAD projection is based on the assumption that over the longer-term, total public sector employment will remain broadly

[14] ONS

constant as a share of total employment (given assumptions on the growth of the working age population and the unemployment rate).

Consideration of evidence to adjust OBR forecasts

Having reviewed the OBR's economic forecasts for the UK, we have considered the extent to which they are applicable to the ENWL LAs. To do this we looked at the composition of public sector employment in the North West to determine the need to make adjustments to the OBR projections to take account of structural differences in public sector employment in the North West versus the rest of the country.

Ideally we would have looked at the breakdown of total public sector employment at the ENWL LA level; however, the required dataset was only available at the regional level. In practice there should not be material differences in the composition of public sector employment between different regions in the North West area.

We focused on reviewing current levels of employment by both sector (Central Government, Local Government and Public Corporations - primarily Non-Departmental Public Bodies) and by industry (i.e. NHS, education, administration), in which public sector employees in the region are employed.

This analysis is relevant because we know that Local Government spending is being cut more significantly than Central Government; therefore if the region has a much higher proportion of its public sector workers employed in Local Government than the rest of the country this might imply that the region will suffer from higher rates of public sector job losses. Similarly, as we know that the NHS budget is being protected in real terms over the current Comprehensive Review Settlement, if the region has a higher share of NHS workers than average this might suggest that the North West will experience a lower level of public sector job losses than presented in the OBR forecasts.

Figure D.2 below shows the breakdown of public sector employment by sector in 2010, across the country. The chart suggests that the North West region has a similar breakdown of public sector employment as the rest of the country. For instance, the average proportion of workers employed in Central Government is 51%, which is equal to the North West's average; employment in both Local Government and Public Corporations is therefore also very close to the UK average.

Figure D.2: Regional public sector employment by sector in 2010[15]

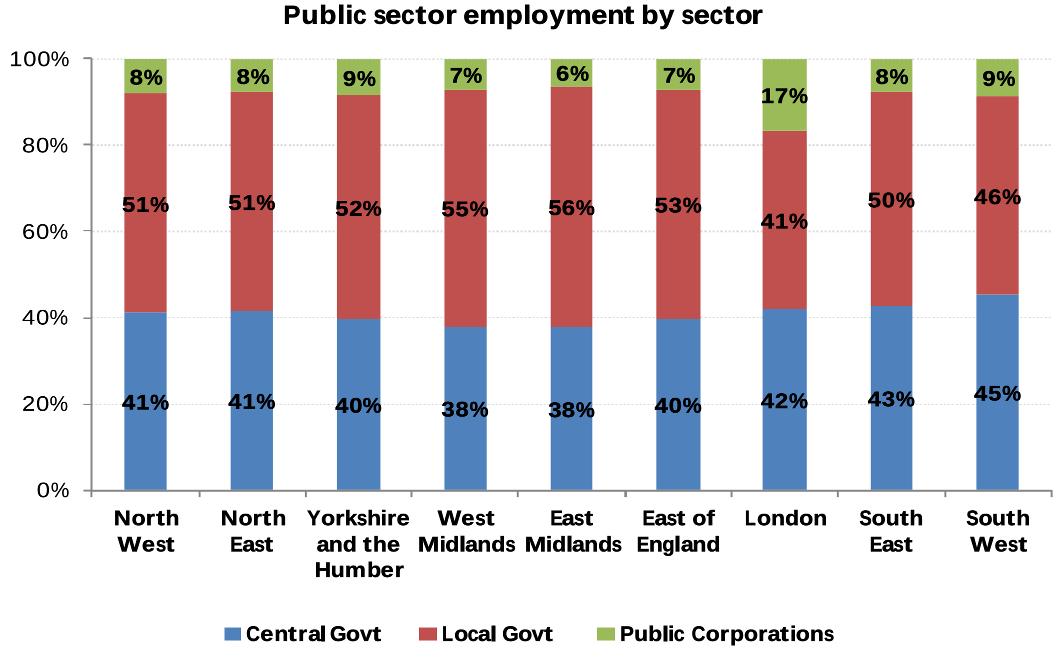
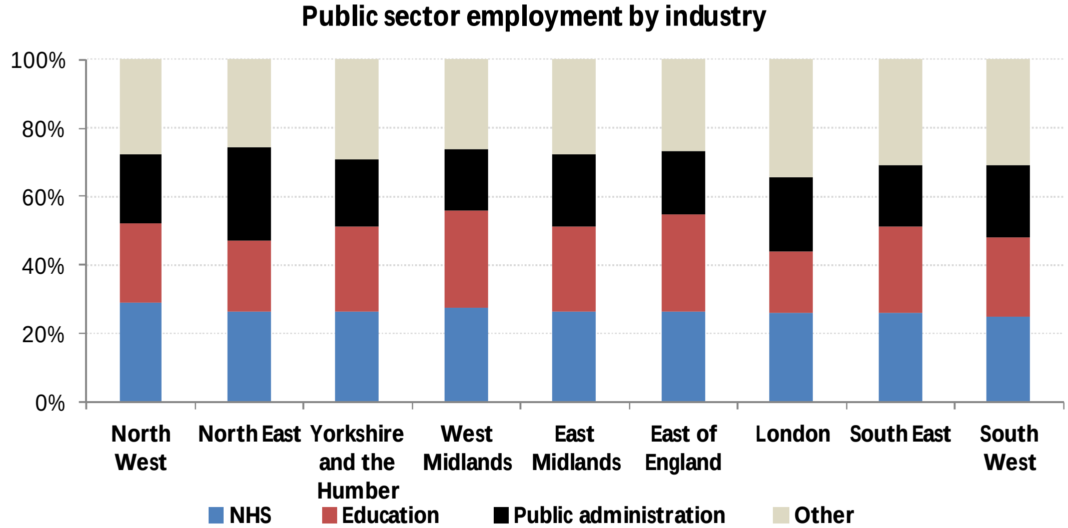


Figure D.3 below considers the 'industrial' classification of public sector workers in the North West. Again the evidence, suggests that the composition of the public sector in the region is similar to the rest of the country. We note that the North West employs a slightly higher proportion of staff in the NHS (2% higher than average), and a marginally lower proportion in Education (1% lower than average), but do not consider that these small differences will create a material difference in the overall level of job reductions in the region.

Figure D.3: Regional public sector employment by industry in 2010[16]



[15] ONS

[16] ONS

Public sector employment growth results

Overall, the evidence that we have assessed suggests that the region has a broadly similar sectoral and industrial composition of public sector workers to the rest of the country. This would imply that it will suffer from a proportionate level of job cuts as part of the Government's efforts to reduce the deficit, making it reasonable to apply the OBR / GAD forecasts to the ENWL LAs. However, we have made a minor adjustment to the GAD projections for 2017/18 to 2022/23 to account for the ONS population projections, which indicate that the working age population in the ENWL LAs will decline slightly over the period (rather than increase, as is the case with the rest of the country).

Table D.1 below summarises the public sector employment forecasts.

Table D.1: Summary of the public sector employment forecasts

	2011/12 – 2016/17	**2017/18 – 2022/23**
Public sector employment growth (average)	-2.2% per annum	0.2% per annum
Sources	• OBR Economic and Fiscal Outlook 2011. • ONS public sector employment by ENWL LAs. • ONS total employment by ENWL LAs.	• OBR Fiscal Sustainability Report 2011. • ONS working age population projections for ENWL LAs.

Applying our forecast growth rate for public sector employment growth across the ENWL LAs implies that total public sector employment will fall from just under 520,000 in 2010/11 to around 450,000 in 2016/7 when Government plans to have achieved the target of eliminating the budget deficit. This implies that total public sector jobs in the ENWL LAs will fall by approx 65,000 over the given time period. Over the longer-term our baseline public sector employment forecasts show total employment in the 35 LAs increasing by around 5,000 between 2016/17 to 2022/23.

D.2.2. Private sector employment growth

Similar to our analysis of public sector jobs growth, to develop the private sector employment assumptions we have reviewed the OBR forecasts and considered the extent to which evidence suggests there is a need to make adjustments to take account of differences between the ENWL LAs and the rest of the country.

OBR forecasts for private sector employment growth

The OBR analysis presented in November 2011 forecasts that private sector employment in the UK will increase by 1.7 million between 2010 and 2017, increasing at an average rate of around 1.1% per annum over the period. To immediately put their forecast into context, during the boom years of the last decade private sector employment growth in the country was 0% per annum on average.

Overall, the OBR base case assessment implies that private sector employment growth in the UK will more than compensate for the reduction of jobs in the public sector. The key assumption that underpins their judgement is that there has been no structural deterioration in the UK labour market as a result of the 'Credit crunch', which implies that there has been no increase in the UK's NAIRU (Non-Accelerating Inflation Rate of Unemployment).

This implication of this for their forecasts is that unemployment in the UK will not change significantly from current levels before falling back to the long-term average in the next few years. They do however acknowledge that there are a number of uncertainties inherent in their private sector employment projections; in particular they note that significant increase in youth unemployment rates (18-24) experienced in recent years may create long-term problems for the labour market.

The OBR private sector employment forecasts provide an important reference point for our forecasts for the ENWL LAs. However, a number of independent forecasters - including the NWRDA forecasting Panel – have a more pessimistic assessment of the private sector's ability to absorb all the job losses in the public sector, while at the same time creating additional new jobs over the next few years.

As part of our analysis we have considered the following when determining the need to adjust the OBR forecasts to make them applicable to the ENWL LAs:

- historic evidence from previous recessions to consider how long it has typically taken for the labour market to return to pre-recession levels;
- a consideration of recent employment growth in the region to assess the current status quo of the private sector employment market; and
- a review of evidence for future prospects for employment growth in the region.

Historic evidence from previous UK recessions

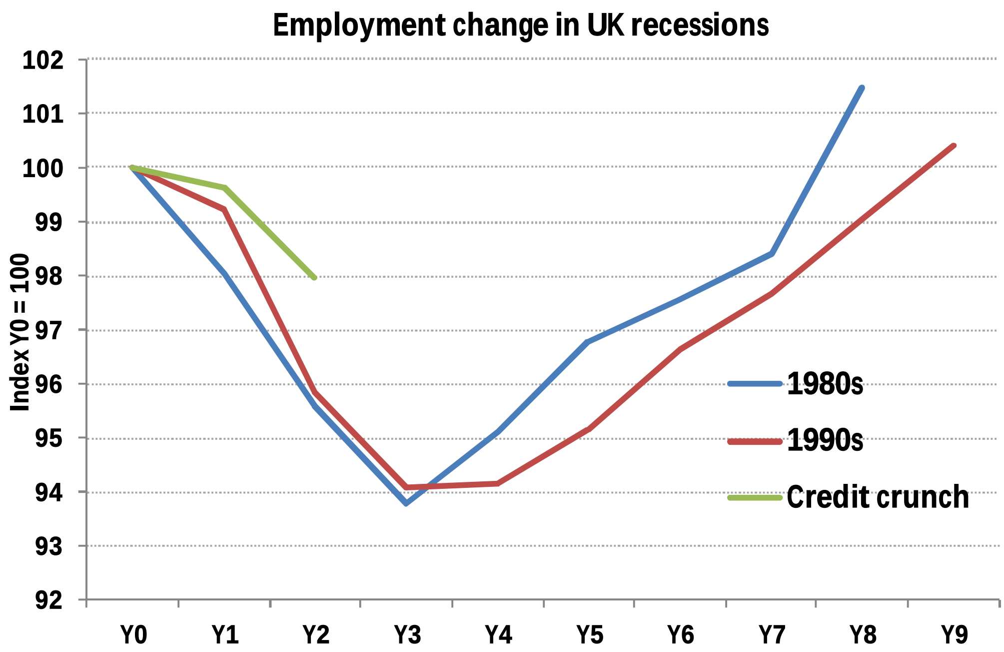
As mentioned above private sector employment growth in both the UK and the North West region has been stagnant over recent years. During the relatively favourable economic conditions experienced in the period of 2000 – 2009 only a total of 1300 new private sector jobs were created in the North West, with private sector employment growth averaging only 0.1% per annum, which is very similar to the 0% average growth per annum experience in the rest of the UK.

It is argued by many economists that the ability of the private sector to create jobs in the last decade was hindered by the strong growth in public sector jobs (public sector employment in the North West grew by 1.8% per annum over the same period); i.e. they believe that public sector employment in the last decade crowded out private sector jobs growth. In their view this implies that the Government's policy of cutting public sector employment will free-up the private sector to deliver significant wage growth in the next few years.

However, the sheer scale of public sector job cuts combined with the weak record of private sector job creation in both the UK and North West, and also the surrounding macroeconomic uncertainty created by the Euro crisis, make it possible that the employment market will take longer to readjust than the OBR currently estimates.

Evidence from the experience of the labour market in previous recessions in the UK supports this assessment. In previous recessions, employment levels have typically taken around seven to eight years to return to their pre-recession peak as the labour market takes time to adjust. For instance, in the recession of the 1990s, unemployment peaked at 10.7% three years after the end of the recession and did not return to pre-recession levels until around 1998. This is illustrated in Figure D.4 below. Further, it is important to note that in the rescissions of the 80s and early 90s public sector employment was contributing to the recovery in the labour market, rather than shedding jobs, the Euro area was not in the same difficult position, and the credit markets were not as constrained as they are at present.

Figure D.4: Employment change following previous UK recessions[17]



Overall, the evidence suggests that the private sector employment market will take longer to readjust than implied by the OBR forecasts. We note that an important feature of the credit crunch recession is the resilience of the employment market – as the above chart shows total employment has not fallen as far as in previous recessions. However, the chart also shows that job losses have typically not peaked until 3-4 years after the recession. Further, current evidence suggests that many employers decided to hold on to their workers during the recession, but reduce wage growth instead, which simply implies that the total scope for employment growth when the economy returns to growth will be lower than in previous recessions; i.e. if private sector employment has fallen more slowly in this recession compared to the past, it will also grow more slowly as the economy recovers.

Historic private sector employment growth in the region

We have carried out a detailed sectoral review of recent employment growth in the North West, the data to carry out this analysis was available only at the regional level rather than specifically for the ENWL LAs.

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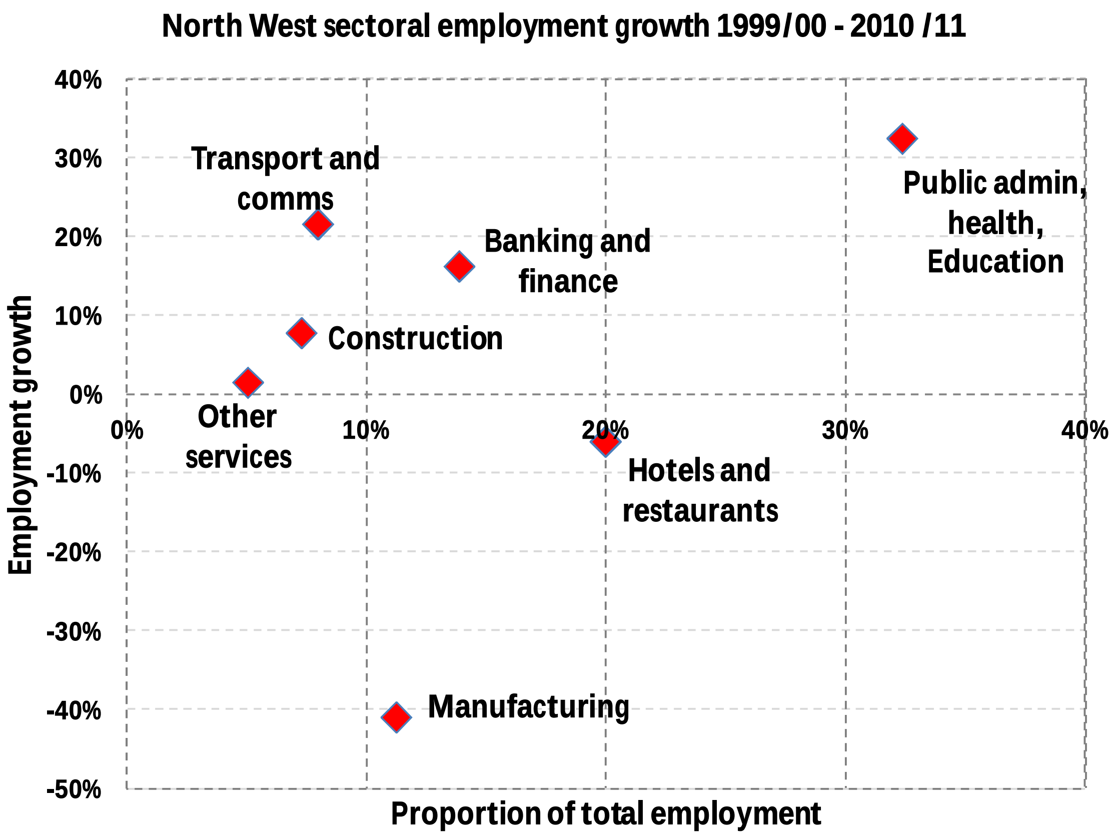
[17] CEPA Analysis

Figure D.5 below provides a detailed look at the sectors in which jobs have been created in the North West in the recent years. It shows the different sectors in which jobs have been created in the region (on the y-axis), and also each of the sectors relative importance in terms of their share of total jobs in the region (on the x-axis). So a reading on the top right of the chart implies that the sector contributes a significant share of jobs in the region and has experienced high levels of employment growth in the last decade. Hence, the chart shows that the public sector has experienced high employment growth and is also the biggest employer in the region (in sectoral terms).

Figure D.5: Sectoral employment growth in the North West[18]



The key message coming from the above chart is that over 50% of the regions jobs are in the public admin (which includes public sector jobs) and hotels/restaurants sector, and that the manufacturing sector has seen the biggest total decline in jobs between 1999/00 – 2010/11, with a 40% decline in jobs, while most jobs have been created in public admin, banking and transport.

In the following sub-section we consider the prospects for employment growth in the key sectors based on the evidence available.

Employment prospects in the region

We consider briefly the prospects for the key areas of the private sector in the region. In this analysis we have considered information presented in the Autumn Statement, the ENWL LAs individual economic plans where available and the NWRDA survey presented in their long-term projections:

[18] *ONS Nomis database*

- **Manufacturing employment** has declined by over 40% between 1999/00 – 2010/11. Going forward the prospects for significant employment growth in the sector are not good. For instance the UK Markit Purchasing Managers Index (PMI) is currently below 50 (December 2011 figure), which suggests that the sector will fall into recession. Furthermore, given that over 50% of manufacturing exports typically go to the Euro area, the sector is highly exposed to ongoing uncertainties caused by the debt crisis. In addition, the NWRDA survey (published in their 2011 forecasts) suggests that employers in the manufacturing sector in the region report that they do not expect to make any significant increase in employment in the coming years. Analysis for the Greater Manchester region by Oxford Economics also suggests that manufacturing employment will continue to fall, albeit at a slower rate over the forecast period.[19]

- The available evidence suggests that employment prospects in the **construction sector** are particularly bleak. The sector is highly reliant on Government spending, and therefore the announced cuts to the budget for social housing, regeneration budgets and the building schools for the future programme. In total the North West Development Agency forecasts estimate that the construction sector will experience a 10% decline in jobs in the region as a result of the cuts to public spending**.**

- Regional forecasters are also pessimistic about the potential for the **hotels and restaurants sector** to act as a source for significant employment growth in the future. In particular the increased uncertainty caused by public sector job cuts and the low growth in real household disposable incomes are cited as factors which will limit growth in the services sector in the region in the future. Though in contrast areas such as Cumbria expect to benefit from increased UK tourism, as UK travellers may be forced to cut back on international travel as a result of lower incomes and the increase in travel costs resulting from Government taxation decisions.

- The prospects for the **transport and communications sector** in the region may be more positive than for other sectors. The Government have announced a number of infrastructure investments in the region, such as the Mersey Gateway Bridge and a £200m plan to electrify railway routes in the region in the years 2013 to 2017. In the 2011 Autumn Statement the Government also announced additional support for technology clusters, with Manchester selected as a location for investment, which may also support employment growth in the sector. Finally, the completion of MediaCity and the relocation of the BBC will be an important driver of employment growth in the sector. In total 2,300 BBC jobs are expected to move to the area over time; furthermore, the presence of the BBC in Salford might attract other businesses involved in the communications sector to locate there. Overall there may be some scope for additional employment creation in this sector.

- Similarly it is not expected that the **banking and finance sector** will experience any significant decline in jobs, particularly given Government's commitment to protect the sector from excessive regulation. However, the sector's exposure to the Euro area financial crisis may limit the scope for employment growth in the short-term.

[19] Oxford Economics (2011) Greater Manchester Forecasting Model

Private sector employment forecasts

The range of evidence that we have considered provides quite a sober assessment of the prospects for private sector employment growth in the region over the period during which the Government will be making cuts to public spending and the public sector workforce. Both the backward looking (recent private sector jobs growth and employment creation following recessions) and forward looking (the sectoral assessments) analysis suggests that it may take some years for the private sector to adjust to the changing economic environment and create the additional jobs necessary to re-balance the economy and return total employment to the pre-recession peak of 2008. While it is difficult to quantify directly much of the analysis that we have carried out, it does suggest that private sector employment growth will not be able to match the central OBR forecasts, over the next five years.

Therefore, our view is that there is sufficient evidence to consider alternative forecasts for private sector employment growth to develop the baseline forecasts. Validation of this judgement comes because simply applying the OBR forecasts would imply unrealistic unemployment rate assumptions given the most recent ONS working age projections for the ENWL LAs.

We have therefore considered the ONS working age population projections for the ENWL LAs, the NWRDA projections and the implied time lag for the LAs to achieve a similar level of employment as experienced in previous recessions for the period to 2016/17. For the period 2017/18 – 2022/23 we assume that private sector employment grows at a rate that is consistent with the region achieving the level of employment that implies that the implies trend levels of unemployment.

Table D.2 below summarises the public sector employment forecasts.

Table D.2: Summary of the private sector employment forecasts

	2011/12 – 2016/17	2017/18 – 2022/23
Private sector employment growth (average)	0.53% per annum	0.12% per annum
Sources	• OBR Economic and Fiscal Outlook 2011. • NWRDA 2011 long-term forecasts. • ONS working age population projections for ENWL LAs. • ONS private sector employment by ENWL LAs. • Historic evidence on labour market experience following a recession (ONS employment data). • Regional assessment of future employment prospects by sector (ONS NOMIS database, HM Treasury Autumn Statement, individual ENWL LA economic plans, NWRDA survey).	

D.2.3. Productivity growth

To develop our projections for baseline productivity growth we have focused primarily on top-down analysis given the limited availability of data. As the availability of productivity data at the Local Authority level is very limited the assessment is based largely on regional data.

We base the analysis on:

- consideration of OBR and other independent forecasters' projections to identify current consensus views of productivity growth in UK;
- analysis of historic productivity growth in the North West compared to the UK to determine if there is any significant difference between productivity in the region, compared to the rest of the UK; and
- consideration of underlying regional trends in key drivers of productivity growth: enterprise growth; skills; innovation and Research & development. This analysis helps to determine if any evidence exists to suggest that there is likely to be a material change in the long-run productivity performance of the region compared to the rest of the UK.

OBR assessment

The OBR assessment focuses on estimating the productivity potential for the UK for the period to the end of 2016/17. Their analysis identifies that in the years immediately following the recession productivity growth in the UK has been very limited in particular in comparison to productivity growth following previous recessions in the UK – growing at only around 1%p.a. They suggest that this is potentially because unemployment has not increased as significantly as would have been expected following the large drop in total output experienced during the recession, this has correspondingly restricted productivity growth. In addition the OBR note that the low levels of credit available to businesses has also potentially restrained productivity growth in recent years, and may continue to do so in the immediate term.

Overall, the OBR judge that the economy will take a few more years to return to trend levels of productivity growth, with below trend levels of productivity growth persisting until 2013-14, beyond which time the economy will return to trend. Underlying this judgement is an assumption that the Credit crunch has not reduced permanently the long-term growth potential of the UK economy.

Therefore, the OBR assume that the economy has the potential to achieve productivity growth of around 1% p.a. in 2011/12 and 2012/13, before returning to the 2% trend growth rate (the UK long-term historic average since 1961).

Consideration of productivity growth in the region

The available evidence suggests that the ENWL LAs have historically underperformed in terms of productivity growth compared to the rest of the UK. In the period 1998 – 2010 GVA growth in the region has fallen below UK GVA growth by an average of around 0.5% per annum. A review of NWRDA analysis suggests that this is marginally higher than the longer-term productivity growth gap of 0.4% per annum that the region has experienced compared to the rest of the UK.

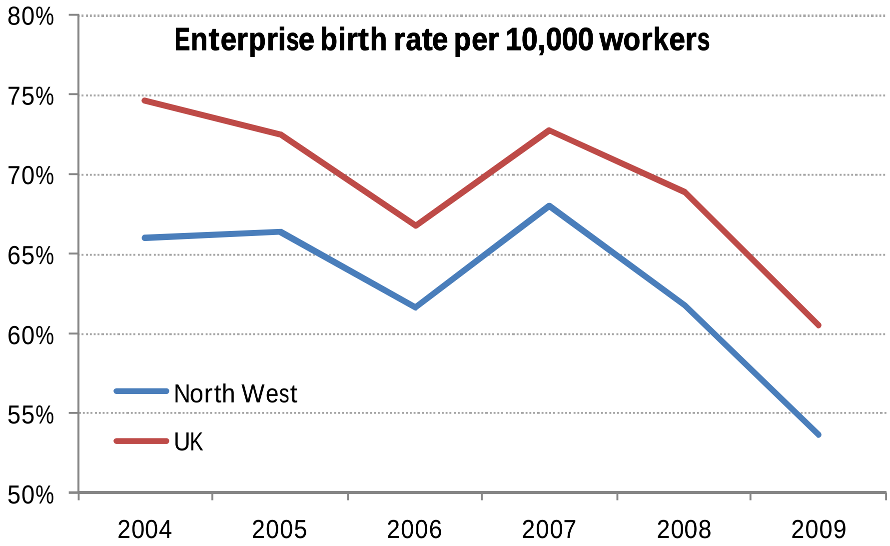
The recent productivity performance in the region is in part explained by the shift away from the higher productivity manufacturing jobs in the region to less productive public sector and service sector jobs. Over the longer-term the underlying productivity gap is explained by the region's underperformance on the key drivers of productivity: skills, innovation, investment and research & development.[20]

To understand why productivity growth in the region has lagged behind the UK, and to help us consider the prospects for closing the productivity gap over the forecast period, we consider the available information on these key drivers of productivity.

Enterprise growth

The available information on enterprise data suggests that the North West continues to lag in performance when compared to the rest of the UK. Data is only available for the period 2004 – 2009 and shows that the number of new enterprises created in the region, as a proportion of the workforce, continues to lag behind the rest of the UK. With the enterprise birth rate currently standing at approx 0.53 per 10,000 working age people in the North West compared 0.61 per 10,000 workers in the UK. See Figure D.6 below.

Figure D.6: Enterprise birth rate 2004 - 2009[21]



However, the evidence does show that new enterprises created in the North West have managed to survive at similar rates to the rest of the United Kingdom, and indeed has a marginally higher survival rate over the longer-term, as shown in Table D.3 below. This suggests that once new enterprises have been established in the region, the overall supporting business environment is broadly comparable to the rest of the country.

[20] The other key driver of productivity is competition policy; there is nothing to suggest that competition policy differs significantly across different regions of the country.
[21] *ONS Nomis database*

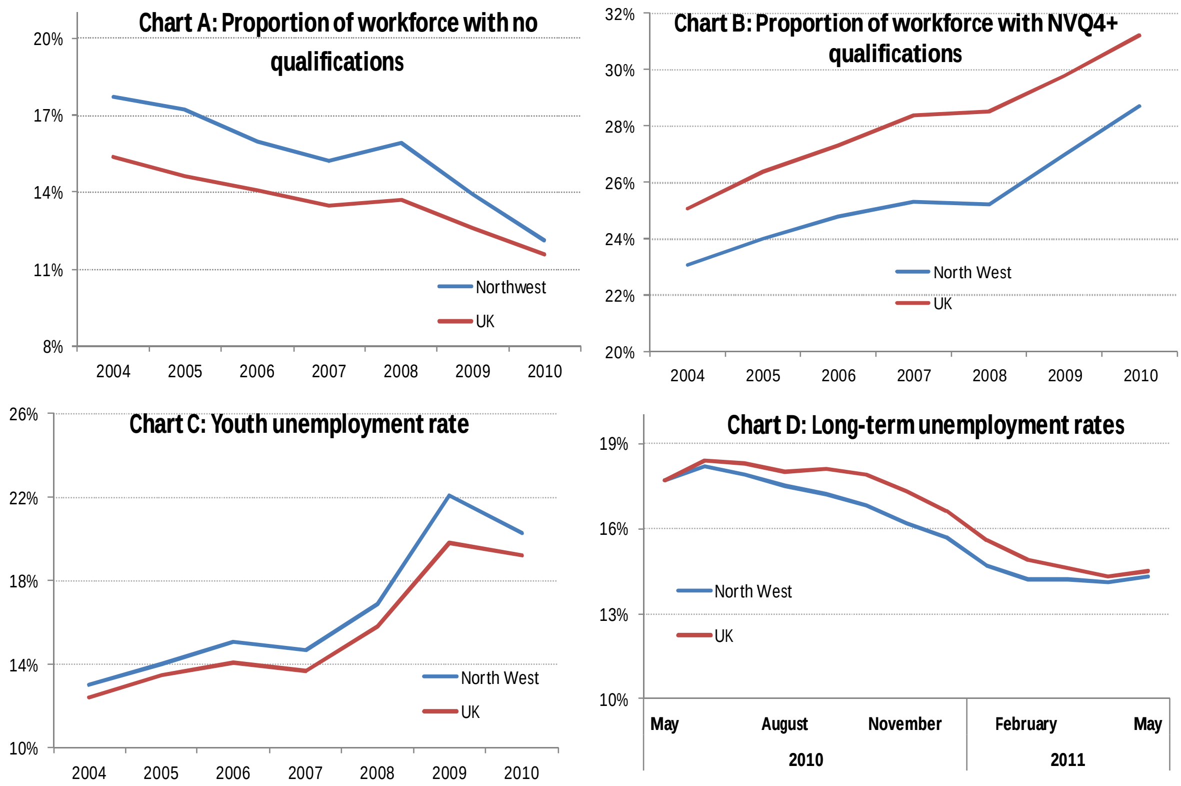
Table D.3: Business survival rates in the region[22]

	1 year	2 year	3 year	4 year	5 year
North West	94.1%	79.1%	66.2%	55.3%	46.8%
UK	94.2%	78.7%	65.3%	54.7%	46.8%

Skills

The available information on current developments in the skills profile in the region compared to the rest of the UK presents a mixed picture, though the higher rates of youth unemployment may be storing up long-term productivity problems in the region. We illustrate a range of indicators in the figure below.

Figure D.7: Indicators of skills and qualifications in the region[23]



The key points to note from the available evidence are as follows:

- Chart A shows that the region has made progress in reducing the proportion of the adult population with no qualifications, falling from 17.7% in 2004 to 12.1% in 2010 and at the same time closing the gap with the rest of the UK.
- However, Chart B shows that over the same time period the gap in the proportion of workers with the highest qualifications (level NVQ 4 and above) between the North West and the rest of the UK has increased marginally from 2.0% in 2004 (overall in the

[22] *Ibid.*
[23] *Ibid.*

North West 23.1%) to 2.5% (28.7%) in 2010, suggesting that the region continues to have a skills gap for the most skilled workers compared to the rest of the country. This is important because the highly skilled workers are crucial in creating new jobs and stimulating enterprise growth.

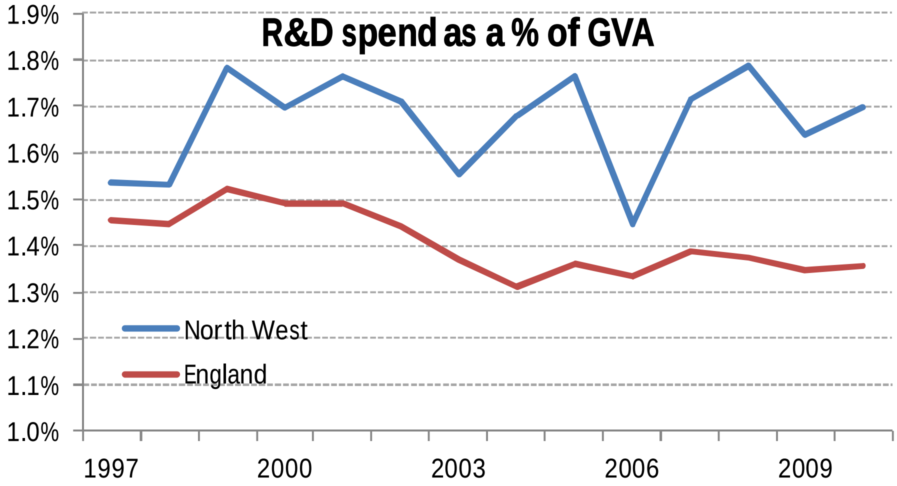
- Another key indicator for both skills and productivity is the youth unemployment rate (16 – 24). This is because unemployment at a young age can cause workers to lose some of the skills that they developed through education and training affecting their long-term productivity rates. Historic evidence indicates that periods of joblessness for young workers is highly correlated with higher rates of unemployment throughout out the rest of their career compared to individuals of the same age. As illustrated in Chart C the North West has seen a significant increase in the youth unemployment rate since the start of the recession, greater than that experienced in the rest of the country. 2010 data shows that 20.3% of 16-24 year olds are unemployed in the North West compared to 19.2% in the UK.
- Chart D presents the long-term unemployment rates (unemployed for more than 1 year) in the North West compared to the UK. Again high rates of long-term unemployment are an important driver of both skills and productivity, as employees experiencing long periods of unemployment may become de-motivated and leave the labour force and also can see their skill levels fall. As chart D shows the North West currently has a similar rate of long-term unemployment as the rest of the UK at around 14.3% of the workforce, compared to 14.5% in the rest of the UK. In the last year rates of long-term employment have begun to fall, though evidence suggests that this is because some individuals have decided to leave the workforce.

Innovation and Research & Development

The available evidence on innovation and Research & Development (R&D) is mixed. Overall, it suggests that the region has an important advantage in R&D spend compared to the rest of the UK; however, the North West lags behind the rest of the UK on based on the available information on innovation.

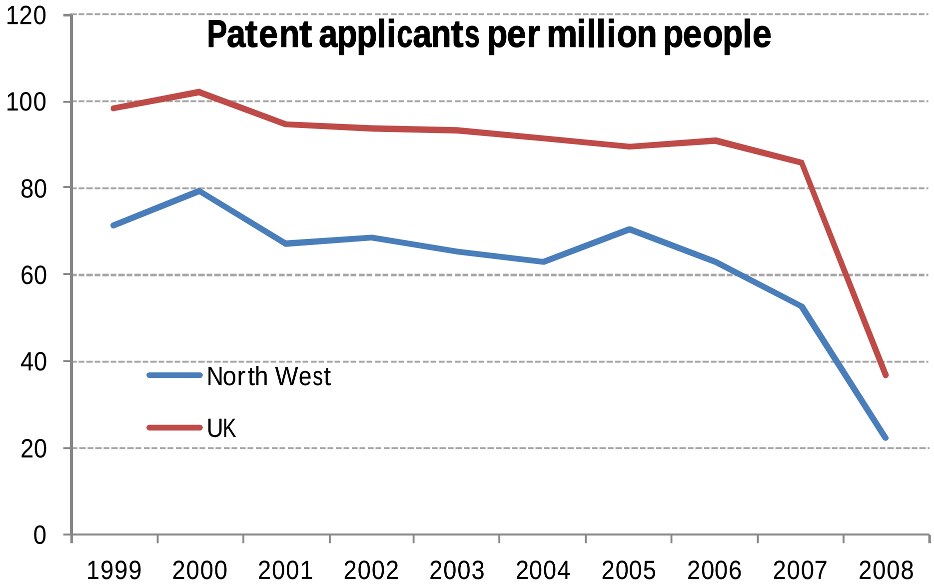
As mentioned above the North West does enjoy higher rates of R&D spend as a proportion of economic activity than the rest of England, this is shown in Figure D.8 below. This is an area of relative strength for the regional economy and could support increased productivity growth in the future. Though it is a puzzle why the higher levels of R&D has potentially not translated into higher levels of innovation in the region.

Figure D.8: R&D spend as a % of GVA[24]



The available evidence on innovation, shown in Figure D.9, shows that the region has on average made significantly lower level of patent applicants than the rest of the country. This is important because patent applications are an important indicator of innovation and suggests that there may be a disconnect between the amount of research being carried out and the ability of that research to generate new products/business ideas to support increased growth.

Figure D.9: Rates of innovation in the region[25]



Investment

There is limited publically available information on investment in the region, so have reviewed published material for this indicator.

[24] *ONS Nomis database*

[25] Eurostat

A review of the North West Regional Development Agency forecasts suggests that investment levels in both the services and manufacturing sectors in the North West have outperformed the UK average over the period (1998 – 2007), when measured as investment as a % of economic activity. This has the potential to support higher growth in these specific sectors in future years, though it should be cautioned that the data might have changed significantly since 2007.

However, overall levels of capital investment per business in the region are shown to lag behind the rest of the UK, with the average business in the region investing £44,200 on capital expenditure compared to £44,800 in the country as a whole.

Summary of evidence on productivity growth

Overall the evidence available to us on the key drivers of productivity performance helps us to understand why the region has continued to lag behind the performance of the rest of the UK.

Compared to the rest of the country the region suffers from lower rates of enterprise, has a skills gap for the most skilled members of the workforce and according to the most recently available information has lost its advantage in terms of investment as a proportion of economic activity. Furthermore, while the region currently suffers from marginally lower rate of long-term unemployment than the rest of the UK, youth unemployment rates in the region have increased rapidly in recent years, which is problematic as youth unemployment is a key indicator of long-term productivity performance.

Therefore, our assessment is that while there has been some progress in some areas, such as the significant reductions in the proportion of the working-age population with no qualifications, there is little evidence in our analysis to suggest that the region has been able to close the historic underlying productivity growth gap with the rest of the country.

Thus for the purposes of our forecasts we assume that the long-term underlying productivity gap of 0.4% per annum between the UK and the North West is maintained over the forecast period. We make an adjustment to take account of the different employment forecasts that we have adopted. This is necessary because over the medium-term, our forecasts imply that the labour market in the region will take longer to recover than suggested by the OBR forecasts and this will lead to a corresponding impact on short-term productivity growth (measured as output per worker), i.e. as employment growth in the UK is higher than we estimate for the ENWL LAs, this would tend to have some impact on reducing productivity.

Table D.4: Summary of the productivity growth forecasts

	2011 / 12 – 2016 / 17	2017 / 18 – 2022 / 23
Productivity growth average	1.9% per annum	1.8% per annum
Sources	• OBR Economic and Fiscal Outlook 2011. • NWRDA 2011 long-term forecasts. • ONS working age population projections for ENWL LAs. • ONS indicators on key drivers of productivity growth.	

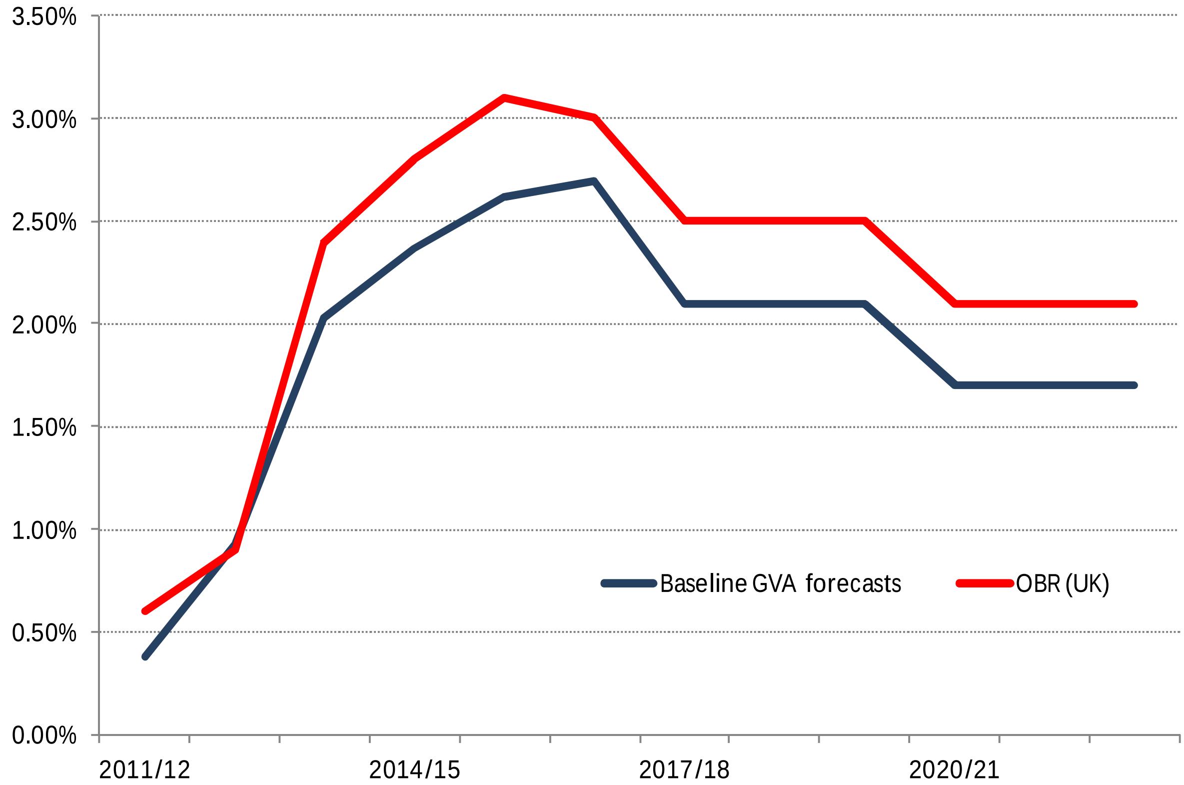
D.2.4. Summary of baseline results

In the previous sections we have carried out a detailed assessment of the prospects for:

- Public sector employment growth;
- Private sector employment growth;
- Productivity growth.

We combine these forecasts to give our overall GVA growth projections for the forecast period. Please note that these forecasts are unique for each of the ENWL LAs, but that for ease of presentation we have combined the results for all the ENWL LAs in Figure D.10 below. For the purpose of comparison we also show the OBR central forecasts for the UK economy in the figure.

Figure D.10: Baseline GVA forecasts for ENWL LAs[26]



The chart shows that our forecasts track below the OBR estimates for the UK throughout the forecast period. This is consistent with the evidence that we have considered, as well as the NWRDA region-specific assessment, both of which suggests that the region will experience a lower rate of jobs growth and productivity growth than implied by the OBR.

[26] *CEPA analysis, OBR*

D.2.5. GVA scenarios

Given the ongoing uncertainty created by the potential impact of the Government's spending cuts and the Euro debt crisis on the recovery, there is clearly a great deal of uncertainty about how the economy will grow over the forecast period. To help manage this uncertainty it is good practice to develop alternative scenarios that illustrate the impact of varying the key assumptions that underpin the baseline forecasts.

In this section we describe both the rationale and assumptions behind the scenarios that we have developed, and present the summary results (please note that we for presentational purposes we have again aggregated the results for all the ENWL LAs).

Economic growth scenarios

As described in Section D.2.4., the baseline forecasts are dependent on assumptions on employment and productivity growth in the ENWL LAs over the forecast period. In our scenarios we thus consider the impact of varying these assumptions, taking account of both upside and downside risks.

We have considered the following scenarios:[27]

- **Aggregate demand trap**, which can be described as a low employment and low productivity scenario, in which the Government's spending cuts, leads to a reduction in economic activity that necessitates additional spending cuts over a longer time period that causes employment growth to weaken in both the private and public sector.
- **High growth**, which includes high employment and productivity assumptions. In this scenario we assume there has been no structural impairment to economic growth in the UK economy, which enables productivity growth to grow much faster than trend for much of the forecast period and for the ENWL LAs to achieve similar rates of private sector jobs growth as the rest of the economy (based on the OBR forecasts) as a result of Government's initiatives to stimulate growth in the North.

We describe each of the scenarios in more detail below.

Aggregate demand trap

While it is generally accepted that the UK needs to take strong action to reduce the size of the fiscal deficit, many economists differ in their views on the overall economic impact of the Coalition Government's planned fiscal consolidation on the UK economy. Some economists believe that the reduction in Government demand and employment will be compensated for by higher private sector demand, i.e. they assume that the Government has been 'crowding-out' private sector activity in the past decade. In contrast, other economists believe that Government is cutting back demand too far and too fast in the middle of a highly uncertain period for the economy. This school of thought is based on the assumption that the private sector in the UK is too weak to increase activity quickly enough to compensate for the reduction in Government

[27] To develop these scenarios we have considered the scenarios presented by the OBR in the November Economic and Fiscal outlook.

demand; i.e. they are of the view that the fiscal multiplier is currently greater than one, as such a reduction in Government demand leads to a larger reduction in overall demand in the economy. In this scenario we illustrate the impact of applying the assumption that the fiscal multiplier is greater than one.

In the aggregate demand trap the key economic outcomes are as follows:

- Government's spending cuts also depresses economic activity in the private sector, as the parts of private sector that are reliant on Government contracts are unable to recover, which then also causes a knock-on impact on other segments of the private sector. This causes private sector employment to grow more slowly than predicted by current OBR forecasts in 2011/12 and 2012/13, which in turn causes private sector growth in the ENWL LAs to fall as well.
- As a result of this outturn, economic growth in the UK falls below OBR forecasts for the next two years, which forces the Government to cut back spending further than currently planned to enable it to meet the deficit reduction targets over the rolling five-year period. We assume that the Government has to cut public spending for an additional two years beyond current plan, which implies that fiscal consolidation will be complete by 2017/18 instead of 2016/17. The net result of this is that public sector employment continues to fall until 2017/18; which causes public sector employment in the ENWL regions to fall as well.
- In this scenario we also assume that the weakness in the employment market also has a knock-on effect on underlying productivity growth in the UK. The higher-rates of unemployment experienced increases the incidence of both long-term unemployment and youth unemployment, both of which are key long-term determinants of productivity growth. In the aggregate demand trap scenario, we therefore assume that underlying productivity growth in the ENWL regions falls over the forecast period, falling marginally more than the rest of the UK because of the higher rates of youth unemployment that the region has suffered from.

High-growth scenario

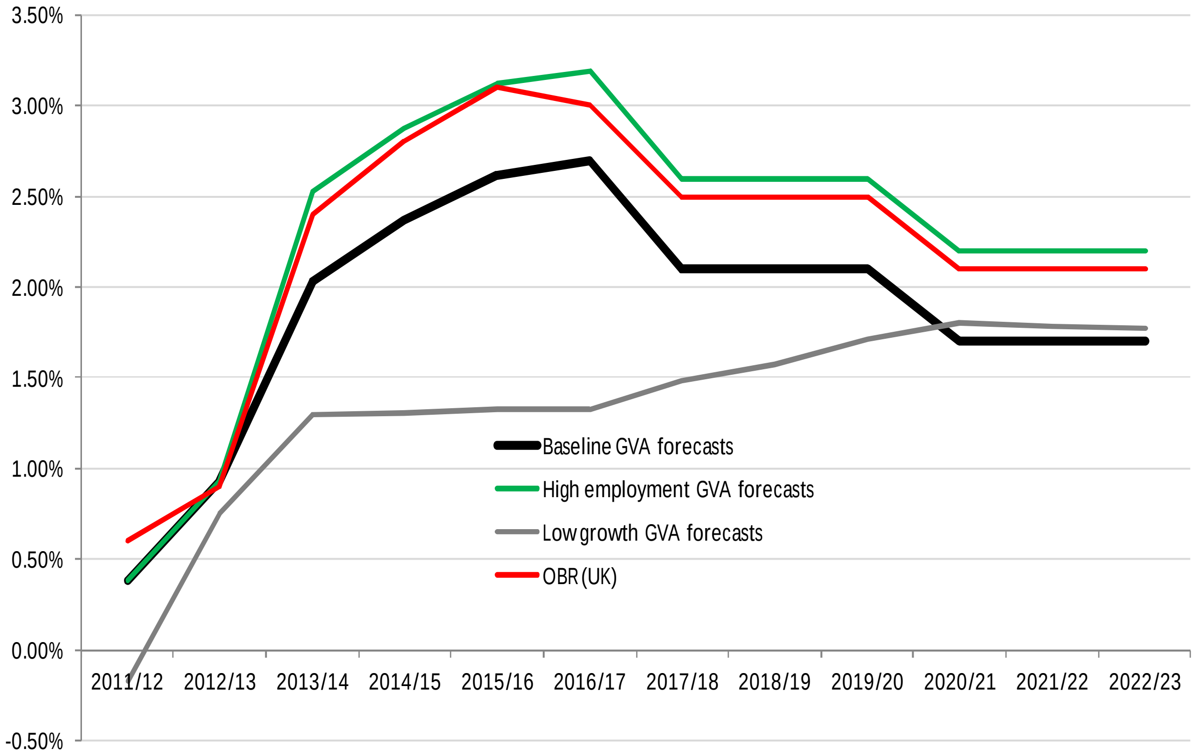
The high-growth scenario is built on the twin assumptions that productivity growth and employment growth in the region are higher than the baseline forecasts. The rationale for the scenario is drawn from the OBR no structural impairment scenario, which assumes that the recession did not cause any structural damage to the UK economy. This assumption implies that there is currently a much higher than forecast level of spare capacity in the UK economy at present, which means that over the coming years the economy has the potential to grow quickly without causing higher levels of inflation.

In this scenario we the higher productive potential in the economy stimulates higher private sector employment growth in the ENWL region than assumed in the baseline case. We assume that the region is able to achieve the higher private sector employment forecasts for the UK developed by the OBR. The higher levels of private sector employment growth could derive from the impact of Government interventions announced in the Autumn statement to support growth in the North West such as the Electrification of the Transpennine Express, combined with the more general support to the private sector through initiatives to improve the coverage of broadband and to extend credit to small businesses in the region.

D.2.6. Scenario results

The results of the scenario analysis are presented below in Figure D.11. We can see that GVA is projected to grow on average by 1.9% per annum in the baseline case, which compares to 2.3% in the high-growth scenario and 1.3% in the aggregate demand trap case. This provides a range within which GVA might grow in the ENWL regions within the forecast period. It is important to note that there are further still downside risks to these forecasts, particularly if there is a disorderly breakup of the EURO area. We have not developed a scenario to take account of this possibility because there are so many different ways in which the EURO area might unravel, each of which would create a variety of economic outcomes that at this stage cannot be quantified in any meaningful way.

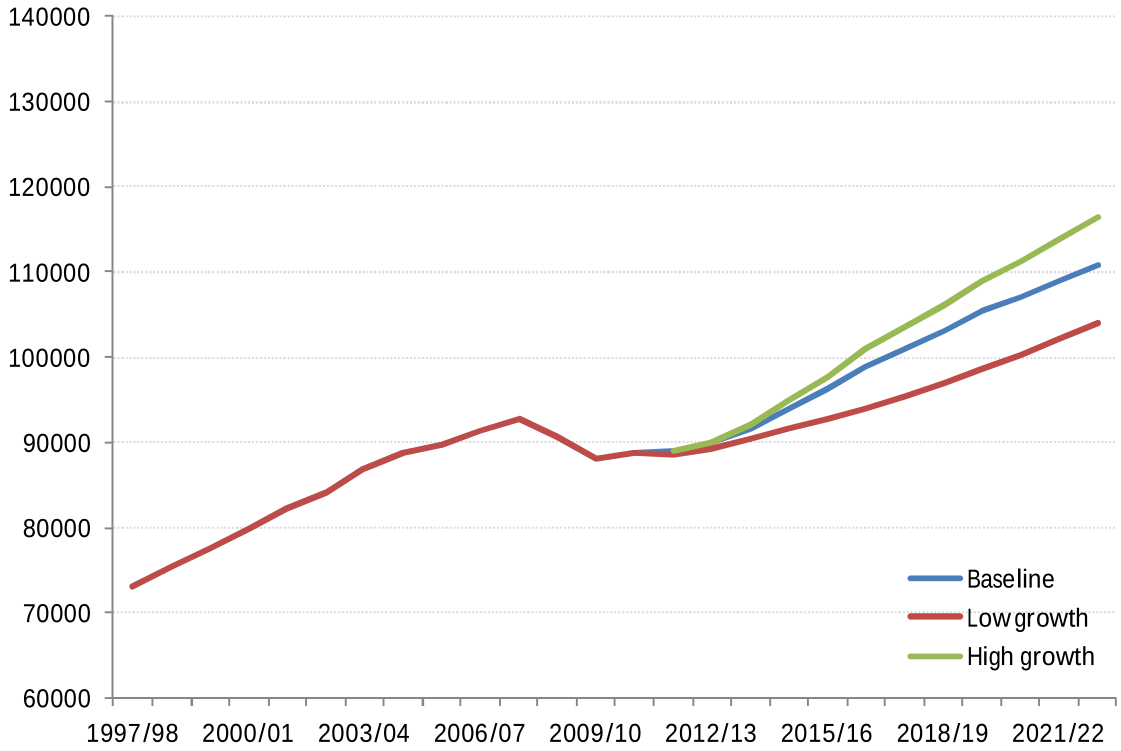
Figure D.11: Economic growth scenarios[28]



We can apply the projected percentage growth rates in the ENWL LAs to the total level of GVA (in £ 2010/11 terms) to consider the impact of the scenarios on economic activity in the region over the forecast period, and also to assess what it implies given the historic growth context. This is illustrated in Figure D.12 below.

[28] *CEPA analysis*

Figure D.12: GVA growth (£m, 2010/11)[29]



In economic terms the GVA scenarios imply quite different outcomes for the ENWL LAs' economy over the forecast period.

- The baseline case implies that the region returns to long-term trend levels of growth experienced before the economic boom of the last decade. This is consistent with the views of economists who believe that the higher levels of economic growth experienced in that period were unsustainable and the result of debt accumulation rather than any structural increase in the UK's productivity potential.
- In contrast the high-growth scenario is consistent with the view that productivity growth did increase significantly in the last decade, as such the economic growth potential in the region (and the UK as a whole) returns to the levels experienced in the last decade.
- The low-growth scenario is based on a more pessimistic economic rationale that the 'Credit crunch' has damaged the long-term growth potential of the UK economy, which has the implication that the economic activity lost during the recession will never be recovered.

D.3. Household income and household formation projections

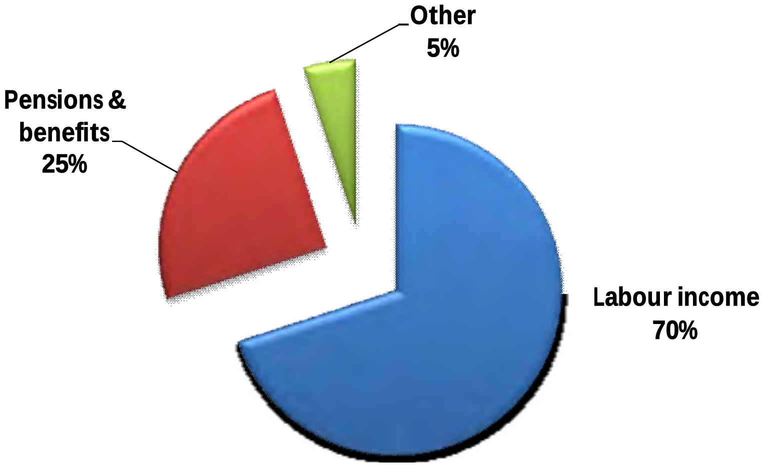
In this section we further set out the approach and results that we have used to develop the household income and household formation growth assumptions.

[29] *CEPA analysis*

D.3.1. Household income growth

To develop the forecasts for real household income growth we have analysed ONS data to establish the key sources of household income. This analysis suggests that household income in the region is derived from income from employment (around 70%), income from pensions and other benefits (around 25%) and income from other sources, which includes sources of income such as returns from savings and investments. This is illustrated in Figure D.13 below.

Figure D.13: Sources of real household income growth[30]



Employment income

The OBR also provide forecasts for earnings growth. These forecasts are broken down into forecasts for public sector and private sector wage growth.

The forecasts for public sector wage growth are provided for the five year period until 2016-17, and reflect announced Government policy. As we have demonstrated in the consideration of public sector wage growth, the composition of the public sector in the North West is broadly comparable to that of the rest of the country. It is therefore appropriate to use the OBR forecasts for public sector wage growth in the ENWL LAs for the period until 2016/17. Beyond 2016/17 the OBR assume that both public and private sector employment wages both increase in line with productivity growth, we again adopt that assumption.

The OBR also produce implicit forecasts for private sector real earnings growth. However, it is not appropriate that we adopt these for the baseline forecasts, as we are assuming a different set of outcomes for the labour market in the ENWL LAs compared to the OBR's assumptions for the overall economy. The different productivity and employment growth assumptions that we have adopted in the baseline forecasts would most likely lead to different rates of private sector income growth.

Instead of using the OBR forecasts we instead assume that real private sector income will grow in-line with our region-specific productivity growth rate assumption. Such an approach is common, and is used by the OBR for their economic projections. We note that income growth is a function of a number of variables such as economic growth, union density, surrounding

[30] ONS

labour market conditions and inflation. We do not have access to a rich enough dataset to carry out the analysis required, for instance, data on the median income for private sector workers is not available as a historical series on the ONS database (data is only available for 2009 – 2011).

Pensions and benefits

The Government has announced its intentions for the growth of pensions and other benefits for the period 2011/12 – 2015/16. The OBR provide estimates of the growth rates in the Economic and Fiscal outlook. It is appropriate to adopt the OBR assumptions for our forecasts as they are based on Government policy that has been announced.

Post 2015/16 we assume that pension and benefits increase in line with earnings growth. This is the approach taken by the OBR in their Fiscal Sustainability report (July 2011), which provides longer-term economic and fiscal forecasts for the economy. The OBR make a few small minor adjustments to this assumption, such as increasing state pension benefits by earnings growth +0.2%. However, as we do not have the data available to disaggregate the proportion of household income sourced from the different types of pensions and benefits, we cannot make a suitable adjustment in our forecasts. Therefore, we simply assume that benefits and pensions increase with prices as well over the longer-term.

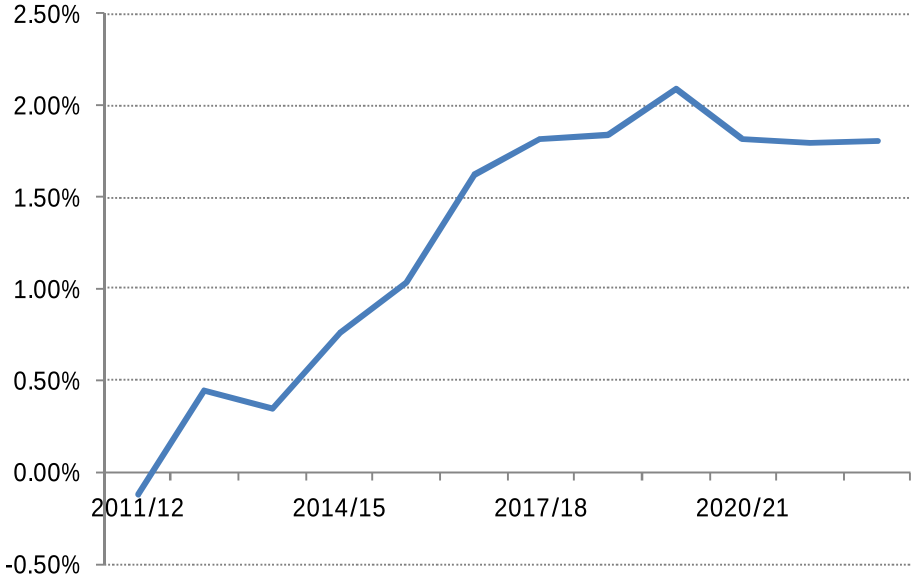
Summary of household income growth forecasts

In summary we adopted the following approach to develop the household income forecasts.

- We adopt the OBR forecasts for the growth in pensions and benefits.
- We adopt the OBR forecasts for the growth in household income gained from public sector employment.
- We assume that private sector wage growth in the region grows in line with the productivity assumption.
- We also assume that household income gained from other sources (estimated to be around 5%) also grows in line with private sector earnings growth.
- We combine these assumptions to develop an overall weighted estimate for real household earnings growth by ENWL LA for each year; the forecasts are unique for each LA given that they each have different rates of public sector employment.

Overall our baseline income forecasts estimate that real income will grow at an average rate of 0.7% per annum to the period 2016/17 and then by around 1.9% in the following years.

Figure D.14: Baseline real household growth forecasts[31]



[31] CEPA Analysis

ANNEX 5 - MARKET TESTING SUMMARY AND MATRIX OF BENCHMARKING

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Contents

1. Executive Summary

The use of benchmarking and identification of best practice have been critical in developing the WJBP for RIIO-ED1.

We benchmark to help us understand;

- How well our organisation delivers services for our customers and stakeholders and;
- What we can do to deliver more.

We see benchmarking as a continuous activity and key to our approach for RIIO-ED1. We use a mixture of internal comparators and benchmarks of national and international organisations to accurately measure our performance and identify best practice. Our engagement with a number of industry forums also allows us to share our best practices with others.

We have also engaged independent organisations to complete much of our benchmarking activity so that we can gain a balanced and unbiased view of how well we have performed and what actions we need to take to improve.

The matrix shows our key benchmarking and best practice activities aligned to our stakeholder priorities.

We have supplemented the benchmarking undertaken to support the previous version of our business plan with two additional activities:

- We have utilised the benchmarking undertaken by Ofgem as part of the fast-track assessment.
- We have undertaken a specific consultation with our supply chain partners and other potential supply chain participants on key unit rates.

Our benchmarking is action oriented i.e. we act upon the results of the benchmark where we believe we can drive a better outcome for our stakeholders. These activities are included in our WJBP for RIIO-ED1.

2. Additional Benchmarking for March 2014 Business Plan

2.1. Benchmarking Key Unit Rates

In order to utilise the benchmarking undertaken by Ofgem as part of the fast-track assessment, it has been necessary to understand in detail the models which make up Ofgem's disaggregated approach and the way they have been used.

This is no easy task as there are over 40 component models. Some of these consider volume and unit cost activity separately; some undertake a combined assessment and others are based on regression analysis. Within the models, a variety of model forms are used, and their results are used in different ways (sometimes comparing to medians; sometimes allowing offsetting, sometimes not; sometimes excluding elements or specific data for separate assessment etc.).

Most of the models include an element of 'cherry-picking' whereby the idealised results are not representative of a position that an individual DNO can realistically achieve. To correct for this, Ofgem include an adjustment to align the consolidated results with those of the identified upper quartile company.

2.2. Modelling observations

Ofgem's models were built to facilitate a fast-track assessment and hence are not necessarily representative of a traditional price control assessment process, despite their detail.

As such, they are generally based on very broad parameters, typically being one of;

- Trend analysis;
- Comparison to median intervention rates; or
- Comparison to median unit costs

For volume assessments in particular, a 'lesser of' rule is usually applied, ie the company gets the lesser of its own forecast or a modelled outcome based on the median rate. In these models, all companies receive downwards adjustments to their forecasts to varying degrees.

Some of the unit cost models do allow offsetting, ie lower than benchmark costs to offset higher than benchmark costs; although this does not universally apply.

Our analysis highlighted that we should focus on a small number of key unit rates for asset replacement, particularly at Extra High Voltage, as can be seen from the table below.

Activity	Unit	Programme Volume	ENWL Unit Rate in submitted in July 2013	Ofgem "Expert View" Rate	Programme Size	% difference
33KV Transformers	Nr	103	£373,340	£272,500	£38,454,020	27%
6.6/11kV CB (GM) Primary	Nr	936	£35,370	£27,500	£33,106,320	22%
33kV UG Cable (Non-Pressurised)	KM	182	£281,890	£263,400	£51,303,980	7%
132kV OHL (Tower Line) Conductor	KM	106	£84,576	£49,200	£8,965,036	42%
LV Pillar (OD at Substation)	Nr	896	£8,987	£7,700	£8,052,659	14%

2.3. Market Testing Consultation with Supply Chain

For each of these five unit rates we have undertaken a specific consultation with our supply chain partners and other potential supply chain participants to understand whether a lower unit rate than included in the previous version of our business plan could be possible. In some areas the supply chain has indicated that we will need to change some of policies or ways of working to enable a lower unit cost. Where this is appropriate after further testing we have committed to make the necessary changes. The details of the feedback from the supply chain and our subsequent revisions are summarised below.

2.3.1. Ground Mounted 33kV Transformers

We have reviewed our unit rates for 33kV Ground Mounted Transformers and compared these with the rates submitted in the well-justified business plans of the other DNOs. This comparison indicated that our rates may not represent what the best in class can achieve and seem to be 27% higher than the rate Ofgem's experts have indicated may be possible to achieve. We have looked at the component elements of this rate and our sourcing strategy. It does not seem that this level of reduction is possible through procurement or reductions via our supply chain. However, our providers have indicated that the most recent rates achieved on the latest jobs may form the basis for a sustainable saving into RIIO-ED1. Furthermore, the design and commissioning elements of the unit rate for these items may present an opportunity for additional reductions. As a result we have reduced this unit rate by 9% giving a £35,000 reduction per unit which reduces our overall programme by £3.6million.

2.3.2. Ground Mounted 6.6/11kV Primary Circuit Breakers

Our unit rates for 6.6 to 11kV Ground Mounted Circuit Breakers do not compare favourably with the rates submitted in the well-justified business plans of some other DNOs and are 22% higher than the target rate used by Ofgem in their cost assessment. We have reviewed recent performance and the best unit costs that have been achieved for the installation of similar circuit breakers. This indicates that a 5% reduction in unit rates is possible. Our RIIO-ED1 plan includes the construction of 936 circuit breakers at this voltage for asset replacement and reinforcement which is an increase on current activity levels. Consultation with our key equipment providers has indicated that an 8% reduction in the unit cost may be achievable through a commitment to a bulk purchasing arrangement. Therefore we have used this information to calculate a new unit rate that is £4,500 lower than our previous plan, a 13% reduction. This unit rate will reduce our overall programme by £4million.

2.3.3. 33kV Underground Cable (Non-Pressurised)

Our rates for a unit of 33kV Underground Cable do not compare favourably with the rates submitted in the well-justified business plans of some other DNOs and appear to be 7% higher than the rate Ofgem's experts have indicated may be possible to achieve. We are aware that the most expensive component of cable laying is the hole that must be excavated for the cable. As a result we have consulted with our supply chain to review whether a change in policy would enable them to tender lower rates. Feedback indicates that a narrower, and therefore cheaper, trench could be achieved by reducing the cover depth and omitting the requirement for covering cable tiles. We have also reviewed our assumptions on how many single and double circuits will be required. Assuming a 60/40 ratio of double to single circuits we believe a significant improvement of 10% in the unit rate can be achieved. This will reduce our overall programme costs by £5million.

2.3.4. 132kV OHL (Tower Line) Conductor

We have reviewed our unit rates for 33kV Ground Mounted Transformers and compared these with the rates submitted in the well-justified business plans of the other DNOs. To do this we created a simple 132kV overhead line costing model using a typical mix of work involved in rebuilding 1km of line, to look at the unit costs in the round and avoid cherry-picking between the tower, conductor and fitting rates.

This comparison indicated that our rates seem to be 42% higher than the rate Ofgem's experts have indicated may be possible to achieve. However, our modelling indicates that some of this effect is caused by creating an 'Expert View' that uses RIIO-ED1 medians for conductors and fittings, but the DPCR5 median for the Towers. This is a substantially lower median rate than would have been determined by using RIIO-ED1 rates only.

We have consulted with our relevant suppliers in the supply chain on this specific rate. Our providers have indicated that the most recent rates achieved on the latest round of tenders should form the basis for a sustainable saving into RIIO-ED1. As a result we have reduced this unit rate by 8% giving a £7,000 reduction per kilometre which reduces our overall programme by £740,000

2.3.5. Outdoor LV Pillars

Our unit rates LV Pillars do not compare favourably with the rates submitted in the well-justified business plans of some other DNOs and are 14% higher than the target rate used by Ofgem in their cost assessment. We have reviewed recent performance of our framework contractors and the best unit costs that have been achieved for the installation of pillars recently. We have also evaluated what it may be possible to achieve by using our own labour resources for this work rather than contractors. Using our direct labour organisation in line with our delivery strategy appears to offer the best outcome and as a result a 5% reduction in unit rates has been forecast. Our RIIO-ED1 plan includes the replacement of 896 LV pillars an increase on current activity levels. This unit rate reduction will reduce our overall programme by £420,000.

2.4. Rising and Lateral Mains

In addition to the consultation with supply chain partners on the five unit rates described above, we have also explored the possibilities of reducing the costs associated with addressing Rising and Lateral Mains (RLM).

We completed a small number of RLM pilot projects using specialist contractors and went to the market for a number of framework contracts to deliver the increased volume of work in the remainder of DPCR5 and the RIIO-ED1 period.

The costing of the RIIO-ED1 RLM replacement programme was previously based on prices quoted by our then-current RLM contractor for work in DPCR5 with an assumed efficiency from a competitive tender process. This additional tendering exercise revealed lower contractor prices than previously forecast and as a result we have reduced the RLM forecast in RIIO-ED1 by £1.6m.

3. Benchmarking Definitions

National Benchmarking	Benchmarks against other UK&I organisations. This includes benchmarking within and outside of our industry sector
International Benchmarking	Benchmarks against organisations outside the UK&I, although predominantly within our industry sector
Best Practice	Activities that are widely recognised as best practice within the UK&I
International Best Practice	Activities that are internationally recognised as being best practice – this includes ISO accreditations

4. Benchmarking Matrix – July 2013

Benchmarking Activity	Reliability	Sustainability	Affordability	Customer	Safety	CSR	Other
Progressing and participation in the BITC Corporate responsibility index						National Benchmark	
ISO 31000 Accreditation in Risk Management - Principles and guidelines							International Best Practice
ISO 14001 Accreditation: Environment Certification		International Best Practice					
Asset Management Accreditation : PASS-55	International Best Practice						
Energy Networks Association: Working groups with other energy companies and electricity DNOs to discuss innovation, best practice and new legislation	Best Practice	Best Practice	Best Practice	Best Practice	Best Practice	Best Practice	
Benchmarking of salary and benefits against market place							National Benchmark
Full compliance with OJEU and procurement laws						Best Practice	
Connections competition benchmarking & feedback from IDNOs and the market place		Best Practice		Best Practice			
Cost efficiency benchmarking exercise against other DNOs using our Finance Steering Group			National Benchmarking				
Tree cutting costs benchmarked against competitive Market prices			National Benchmarking				
Engagement with the Institute of Customer Service (ICS) - Facilitate benchmarking visits to customer leading organisations to see and learn from best practice in action				Best Practice			
Business wide benchmarking against the competitive unregulated asset management industries (Mott MocDonald)	National Benchmarking				National Benchmarking		National Benchmarking
IT Services benchmarking by the Gartner group (Scope, Service level and cost)			National Benchmarking				National Benchmarking
PB power benchmarking of volume plans against reliability objectives to identify alternative approaches and best practices	National Benchmarking		National Benchmarking				
AccountAbility benchmarking of stakeholder engagement strategies against other DNOs: Our description of our 2012/13 stakeholder engagement programme for the reporting year ended 31 May 2013 has been independently assured against AA1000APS principles in accordance with the International Standard on Assurance Engagement 3000				National Benchmarking & Best Practice		National Benchmarking & Best Practice	

Benchmarking Activity	Reliability	Sustainability	Affordability	Customer	Safety	CSR	Other
Demand forecast, derived from general UK government economic forecast and regionalised by CEPA	National Benchmarking	National Benchmarking	National Benchmarking				
Low Carbon Technology volumes as per DECC forecast		National Benchmarking					
LCT intervention costs for secondary network derived from UQ costs contained in the Transform model as instructed by Ofgem		National Benchmarking	National Benchmarking				
Maturity modelling of Investment levels in IT in comparison to similar size/type organisations			International Benchmarking				
Benchmarking into the Cost of Finance function as a percentage of company revenue (UK companies)							National Benchmarking
IT budget as a percentage of company revenue (international electricity sector)			International Benchmarking				
Property : Average amount of workspace available per employee			National Benchmarking		National Benchmarking		
Assessments and Comparison for the appropriate size of a Trouble call organisation - benchmarked against similar scale UK organisations	National Benchmarking		National Benchmarking				
Benchmarking of UK in-house contact centres - key measure cost per inbound call			National Benchmarking	National Benchmarking			
Independent high level analysis of Corporate Competitiveness against other similar scale organisations (KPMG)						International Benchmarking	
Independent assessment of asset management practices - Maturity Modelling of CBRM comparative assessment against Asset management cycle model (Mott McDonald)	Best Practice						
Extensive market testing and tendering in the market by the Procurement Team			National Benchmarking				
Independent review of all fixed and CAI costs for RIIO-ED1			National Benchmarking				
Independent assessment of Business support costs and Closely Associated Indirect (CAI) costs in context of RIIO-ED1 process and potential for outsource activity: includes all functions and directorates, Fixed and semi variable cost analysis, labour and pension cost and outsourcing benefit assessment			National Benchmarking				
Independent review of Single Licence vs. multi- licence advantages and disadvantages for RIIO-ED1 (KPMG)	National Benchmarking	National Benchmarking	National Benchmarking	National Benchmarking	National Benchmarking		

Benchmarking Activity	Reliability	Sustainability	Affordability	Customer	Safety	CSR	Other
Annual Employee Opinion Survey	Best Practice	Best Practice	Best Practice	Best Practice	Best Practice	Best Practice	Best Practice
IET (Institute of Engineering and Technology) Accreditation for our Graduate programme							Best Practice
Maintain our OHSAS18001 accreditation for Health and Safety Management					Best Practice		
Achievement of Guaraneteed Standards of Performance (GSOPs) :standards of customer service backed by a guarantee - customers receive a payment, either directly from us or through their electricity supplier, if we fail to meet these standards.	Best Practice			Best Practice			
Comparisons on smart grid technology with Australia Grid and New Zealand looking at LCT management particularly PV installations incl. network topology, operating practices and in particular dynamic operation of the systems. Ideas incorporated into our C2C project	International Benchmarking	International Benchmarking					
Reference client engagements with GB DNOs and US electricity and gas companies to understand the maturity of the Smart grid roadmap and intregration to Advance Meter Infrastructure (AMI)		International Benchmarking					
The Procurement Team engage in 'soft benchmarking' exercise with other international procurement companies shared learning of best practices and costs comparisons			International Benchmarking				

ANNEX 6: PROCUREMENT STRATEGY

Electricity North West Limited
Registered Office:
304 Bridgewater Place,
Birchwood Park,
Warrington,
Cheshire.
WA3 6XG.
Registered no: 2366949 (England)

Contents

1. Executive Summary

The long term nature of operating an electricity distribution business lends itself to arranging procurement on a strategic sourcing basis, with a dedicated in-house team providing the continuity required by this approach and ensuring legal, market and service knowledge retention,

The key categories adopted within Electricity North West are:

Electrical Equipment

Long term framework agreements are put in place to guarantee formalised contractual coverage on over 85% of this expenditure Category. Detailed knowledge of the forward capital programme has been used to develop a Volume Banded Pricing Matrix. This mechanism enables suppliers to price volumes in a risk-free way, guaranteeing the optimum commercial offer. For key items where there is commonality of technical specification, we collaborate with other DNOs to consolidate volumes via the Selectus consortium. The greater economies of scale facilitated through this strategy have delivered significant savings.

Construction

A critical success factor in this category is the creation of an effective contracting strategy and formation of productive and mutually beneficial relationships with suppliers. For Electricity North West this is facilitated by placing a range of long term framework contracts to cover the main Secondary Networks works including Underground Networks, Overhead Lines, Substation Works and Minor Civils activities.

Whilst Tier 2 suppliers are used to execute the long term frameworks, Tier 3 suppliers have been proactively developed on some of the project specific challenges. This has delivered significant additional savings by reducing management charges and main contractor margins. The adoption of a more flexible approach to payment terms has been an important enabler in this initiative.

In the case of Grid and Primary projects, the works are of a more concentrated nature and a greater financial value. This type of activity lends itself to Project Specific Tendering in order to realise the additional commercial benefits that are available from suppliers' economies of scale.

The size of some of the Grid and Primary projects, coupled with the general construction market downturn, has allowed new potential suppliers to be introduced into areas of the UK market which were previously specialist areas with very few market players.

Business Services

One of the key areas of focus within the Business Services category is the reduction of back office transaction processing time. Tools, Equipment, PPE and Travel are all being transferred to Electronic Catalogue ordering to reduce administration and to provide improved management information.

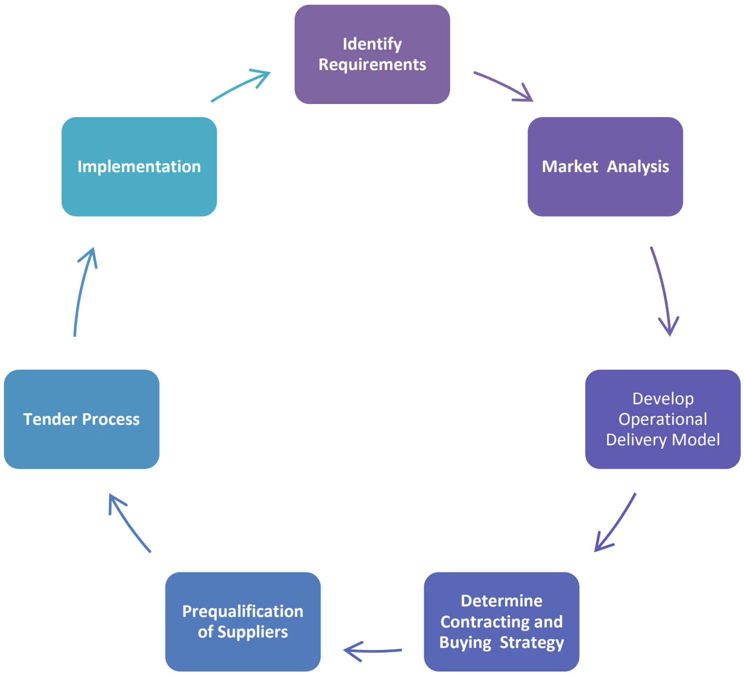
In the logistics area, a trial has been carried out involving the daily delivery of materials direct to site with the aim of reducing non-productive time for cable jointers and linesmen. Following the success of this trial, the resulting methodology has now been encompassed within the scope of works for the recently awarded Logistics Service Provider contract.

2. Category Approach

2.1 Overview of our procurement strategy

The long term nature of operating an electricity distribution business lends itself to arranging Procurement on a Strategic Sourcing basis, with a dedicated in-house team providing the continuity required by this approach and ensuring knowledge retention. By applying this strategic approach throughout an entire organisation the results are significantly greater than traditional, transactional based purchasing negotiations.

The Procurement process flowchart for an individual market initiative is illustrated in the diagram below.



Sourcing is initiated and closed out through the Achilles Vendor Database. For materials contracts, stock levels are managed by the Logistics service provider to match supply with business demand.

A Category Management structure underpins all procurement within Electricity North West. Typically, Senior and Junior Buyers work in pairs, taking full responsibility for a key area of expenditure.

This degree of specialisation facilitates the development of detailed product knowledge and market awareness and allows the Buying team to develop highly effective stakeholder relationships and a true understanding of future requirements. The development of a long term Category Plan ensures that each team is able to maintain the focus on Strategic initiatives as well as responding to the daily challenges of stakeholder and supplier demands.

Guiding principles have been developed for each category which ensure that each individual tender initiative is aligned to long term business objectives.

The close collaboration with suppliers encouraged by the Category approach enables wider business benefits to be unlocked through supplier innovation.

The key categories adopted within Electricity North West are listed below with the key features being documented in the following sections, further described below:

- Electrical Equipment
- Construction
- Business Services

2.2 Electrical Equipment Category

2.2.1 Delivery

Years of market consolidation and supplier closure, coupled with high barriers to entry for potential new entrants, have resulted in a relatively narrow field of suppliers competing in the various markets for Electricity Distribution Equipment in the UK. This combines with the ever-present risk of product quality issues and periodic operational bans to make supply chain continuity the top priority for this category to ensure minimal risk to customer services.

As a matter of course, a minimum of two suppliers are sought for the majority of strategic items, including all transformer, switchgear and cable types across the full voltage range. Long term framework agreements are put in place to guarantee formalised contractual coverage on over 85% of Category expenditure.

A formal Business Continuity Management process is used to establish the key areas of exposure across the product portfolio. In cases where only one contracted supplier is available, a formalised supplier health monitoring regime is initiated with the aim of triggering an early warning of potential issues. In parallel, the Buying team proactively work to establish alternative sources of supplier or to establish contingency solutions. Where this is not possible, levels of stock are set at increased levels to reduce service level risks.

In the case of non-core ancillary items a move to longer framework periods has been initiated with the aim of reducing costs associated with tendering, redesign, supplier transition and training.

2.2.2 Commercial Approach

In this category it is more difficult to influence price purely through competition, due to the consolidated nature of the supplier base. Buyer power is further restricted by the relatively low volumes available to Electricity North West as a single DNO. Furthermore, non-European suppliers tend to enter the European market only for larger projects such as 132kV switchgear renewals. These factors tend to combine to result in a “market price” for many products.

Notwithstanding these challenges, a number of initiatives have been implemented to enhance our commercial position in this category.

Whilst the traditional utility approach has been to enter in to contracts with no guarantee of volumes, Electricity North West have utilised the strong business knowledge engendered by the Category Management approach in order to amend this methodology. The detailed knowledge of the forward capital programme has been used to develop a Volume Banded Pricing Matrix which is utilised when going to market for key strategic items. This obtains supplier prices based on ranges of overall product volumes as well as the traditional “no-guarantee” price. By requesting all suppliers to price on this basis the Buyer gains an informed view of how the market values the opportunity. This enables the Buyer to run various scenarios and to determine the optimum award strategy from a commercial and delivery risk perspective. Contract Prices are then set for the framework duration, based on the agreed volumes. In the event of lower, or higher, volumes being delivered, the rates will revert to the pricing appropriate to the delivered volumes as detailed in the matrix. This mechanism enables suppliers to price volumes in a risk-free way, guaranteeing the optimum commercial offer. The underlying principle is to build enough flexibility into the process to let the market decide the optimum solution, rather than narrowing down options by attempting to second-guess the market.

For key items where there is commonality of technical specification, we collaborate with other DNOs to consolidate volumes via the Selectus consortium. The greater economies of scale facilitated through this strategy have delivered additional savings in the case of cable purchase.

A number of key strategic items within this category feature a direct link to commodity price levels for metals and oil, with particular examples including cables, transformers and overhead conductor. Our strategic approach is to determine any key commodity issues in advance of going to market and to then specify the parameters to be included in a Contract Price Adjustment (CPA) formula. This builds in sufficient uniformity to enable all supplier returns to be compared on an equal footing. CPA formulae are always based on routinely published data which is available in the public domain.

Open ended Price Review clauses are avoided in supply contracts in order to mitigate the risk of uncontrolled price escalation. Prices are either fixed or, alternatively, linked to a publicly available index. Where possible, prices are fixed in Sterling, eliminating currency risk during the contract period. Award criteria are typically focused on Price, Technical Compliance, Delivery, Experience and Contract Management.

2.2.3 Innovation

Due to the low level of competitive forces within this category, the area with the greatest potential for positive impact is innovation. Whilst change is typically evolutionary rather than revolutionary due to the nature and age of the electricity supply industry, the long term benefit of cumulative marginal improvements should not be underestimated. The Procurement team play a key role in promoting and supporting new initiatives with examples including:

- Network Automation
- Innovation Funding Initiative projects
- Low Carbon Network Fund projects
- Standardised Design Solutions
- Containerised Substations

2.3 Construction Category

2.3.1 Delivery

This Category represents the largest single area of external expenditure for Electricity North West and constitutes a major part of the Capital Programme.

Whilst, historically, delivery has been through larger, management contractors, the current regulatory period marked a move to typically smaller suppliers with directly employed workforces possessing the required skill sets enabling greater control over delivery by removing a layer of management that was not adding significant value to the overall offering.

A critical success factor in this category is the forming of productive and mutually beneficial relationships with suppliers. This is facilitated by placing a range of long term framework contracts to cover the main Secondary Networks areas including Underground Networks, Overhead Line, Substation Works and Minor Civils activities.

Formal periodic reviews enable progress to be closely monitored and timely resolution of issues. Where activities are of a more specialist nature, bespoke frameworks have been put in place to ensure that appropriately qualified and experienced suppliers are engaged.

2.3.2 Commercial Approach

The general downturn in the wider construction market coupled with the appeal of the continuity of work available within utility markets has resulted in a situation where the Construction category offers the greatest opportunity for commercial benefits. At present the market is highly competitive with relatively low entry barriers to suppliers from related fields. As base costs are largely labour related, there is significant scope for suppliers to offer attractive rates in order to secure work. Whilst this benefit is proactively sought and secured, it is also important to realise that the situation is now showing signs of reversing as the wider construction market recovers.

The majority of secondary networks activities are carried out using framework agreements that have been competitively tendered based on a range of activities spread across a wide geographical area.

In the case of Grid and Primary projects, the works are of a more concentrated nature and are of a greater financial value. This type of activity lends itself to Project Specific Tendering in order to realise the additional commercial benefits that are available due to the greater economies of scale. This strategy has been widely adopted on 33kV and 132kV cable laying and 132kV overhead line refurbishment projects. The key to success in this area is to establish long term visibility of the forward programme, enabling strategic and tactical decisions to be made with respect to which projects are suitable for tendering, including potential grouping strategies to generate further scale economies.

In the secondary networks arena, initiatives have been introduced to separate out suitable programmes from the secondary networks frameworks, enabling optimum pricing levels to be established from suitably qualified and incentivised suppliers. Examples of such opportunities include regional cut-out change programmes and groupings of 11kV Overhead Line Refurbishment projects.

Whilst Tier 2 suppliers are used to execute the long term frameworks, Tier 3 suppliers have been proactively developed on some of the project specific challenges. This has delivered significant additional savings by reducing management charges and main contractor margins. The adoption of a more flexible approach to payment terms has been an important enabler in this initiative.

An important principle underpinning the approach in this category is to maintain flexibility on the award of packages in order to enable the market to determine the optimum commercial option. The Bredbury 132kV switchgear replacement project is a particular example in which the tender has incorporated pricing options for both turnkey and package awards in order to avoid eliminating the optimum commercial option.

Award criteria are largely price based to maximise commercial benefit, with technical competency being the predominant selection criterion at the pre-qualification stage.

2.3.3 Innovation

The size of some of the Grid and Primary projects, coupled with the general construction market downturn has allowed new potential suppliers to be introduced into areas of the UK market which were previously specialist areas with very few market players. An example of this, delivering significant commercial benefits, was the award of a 132kV overhead line refurbishment project to an Irish contractor, Powerteam. Once introduced to the Electricity North West area, Powerteam were able to propose an alternative catenary system on a subsequent project, introducing competition to a type of project that had previously been a sole source situation.

After carrying out detailed root cause analysis of construction variations on G&P projects, the tender process was redesigned, moving the responsibility for Ground Conditions to the contractor – with very little cost but significant benefit in terms of minimisation of future variations.

2.4 Business Services Category

2.4.1 Delivery

This is the most diverse Procurement category, covering all indirect spend areas including Consultancy, Fleet, Field Support, Office Support, IT and Telecom, Facilities Management and Logistics.

With the exception of the more specialist technical consultancy areas, these sub-categories tend to be characterised by large numbers of available suppliers, leading to reasonably high levels of competition. A further aspect of the category is that supplier relationships tend to be particularly important as service scope often continues to evolve during a contract period. Driven largely by these two factors, typical delivery strategy is to award relatively long framework contracts to a single supplier. Award criteria will cover a wide range of delivery criteria as well as price.

Procurement strategy is to use outsourcing to facilitate peak lopping and to perform specialist tasks. Where a core activity with a steady requirement is being carried out by external suppliers, initiatives are put in place to bring the activities in–house. Examples include Transaction Processing, with attention having focused on Quantity Surveying and currently on Civil Design. This move encourages knowledge retention as well as cost control.

2.4.2 Commercial Approach

Within any business it is common for the Business Services category to feature a lower rate of framework compliance with expenditure spilling out across a wide range of ad-hoc suppliers due partly to the diverse range of services.

A key element of strategy within this category is to carry out monthly spend monitoring to assess framework coverage within each expenditure area. Exceptions are analysed and addressed either through stakeholder education, or initiating new frameworks, where appropriate, to ensure that business is conducted on clear commercial terms.

Increased control of purchasing presents a further opportunity for commercial improvement. All new frameworks feature provision of detailed management information designed to facilitate identification of variances in demand on an individual or regional basis for subsequent action. In parallel with this process, a review of all routine spend areas, such as Tools, Personal Protective Equipment and Stationery, is being carried out with a clear aim to seek HSE Compliance, control and visibility whilst reducing expenditure.

The Selectus purchasing consortium is utilised to maximise buying power in areas of specification commonality. An excellent example is in framework contracts for purchase of commercial vehicles and company cars, where Electricity North West combine volumes with Northern Power Grid, Scottish Power, United Utilities, Scottish Water and Northumbrian Water to secure best value from vehicle manufacturers.

2.4.3 Innovation

One of the key areas of focus within the Business Services category is the reduction of back office transaction processing time for Electricity North West. Tools, Equipment, PPE and Travel are all being transferred to Electronic Catalogue ordering, to reduce administration and to provide improved management information. The adoption of electronic ordering also makes it easy to implement and control product rationalisation through the use of approved lists.

Management Information is used to great effect in the fuel category where weekly information is circulated regarding cheapest pump prices for each geographical area, followed by exception reports featuring examples of operatives not following this guidance.

In the logistics area, a trial has been carried out involving the daily delivery of materials direct to site with the aim of reducing non-productive time for cable jointers and linesmen. Following the success of this trial, the resulting methodology has now been encompassed within the scope of works for the recently awarded Logistics Service Provider contract.

3. Performance Initiatives

A number of generic initiatives have been implemented across all of the Procurement categories targeting improved performance and uniformity of process.

A structured Governance process ensures alignment through a hierarchy of levels starting with an overarching Procurement Strategy and passing through Category Plans, Monthly Category Reviews and individual Tender Strategies. Stakeholder communication is a particular strength utilising weekly updates of all on-going tenders, regular category newsletters and Project Specific briefing slides.

Staff training has been a major drive, with all Buyers being put through the Achilles Academy modular course to ensure that the whole team have a common level of proficiency with regard to the EU Procurement legislation. Further training programmes include Contract Structure and Numerical Analysis with the aim being to establish standardisation of approach.

Process rationalisation has been focussed on implementing a uniform standard for Tender Files, facilitating easy handover between Buyers if required. Now that filing has been standardised this has improved efficiency through the elimination of paper records.

4. Sustainable Procurement

Typically, suppliers for larger contracts and regular requirements are sourced from the Achilles Vendor Database. This mitigates supply chain risk by ensuring that potential suppliers have appropriate controls in place with regard to Quality, Health & Safety, and Corporate and Social Responsibility, including Environmental Considerations and Carbon Footprint.

Supply chain analysis has been carried out at product level, mapping the potential for non-compliance with Environmental and Social standards, against the business criticality of that product group. This process facilitates the establishment of priorities for action across the categories, enabling the incorporation of product-specific sustainability considerations within the tender process. Examples include:

- the reuse of packaging across the Electrical Equipment category,
- use of timber from sustainable sources for wood poles,
- assessment of suppliers' approach to labour standards and welfare on the workwear tender, and
- the agreement of Primary Transformer manufacturers to utilise reprocessed insulating oil from the Electricity North West network when supplying new units.

Whole life costing is routinely utilised within the tender assessment process for electrical equipment, encouraging a wider perspective on costs including sustainability aspects.

Robustness of the Electricity North West supply chain is proactively managed via a programme of monthly Business Continuity Management meetings. These establish a Red / Amber / Green rating for each product area, based on the number of contracted suppliers, level of expenditure, criticality of product and level of supplier performance. Action plans are in place within each category to address areas where contractual coverage or supplier performance can be improved. In addition, a process of financial monitoring is in place for all key suppliers in order to provide an early warning of potential issues.

Supplier diversity is encouraged, including the provision of opportunities for SMEs and the stimulation of local economic growth, within the bounds of the EU Procurement Legislation. Strategies for working with SMEs include agreeing shorter payment terms where appropriate, assisting in the development of operational staff and identification of growth opportunities for existing suppliers. In 2012, 505 North West based suppliers formed a significant proportion of the total supplier base of 1250, receiving £52m of orders from a total of £200m. Furthermore, many of the suppliers whose head offices are outside of the region still deliver services through North West based staff, creating local employment opportunities.

5. Relationship to Delivery Strategy

The delivery model strategy has been targeted to support our proposals for the RIIO-ED1 period. In particular the developments we have put in place over recent years have provided a firm and robust platform on which to build further improvements in customer service, robust delivery capacity and improving delivery efficiency.

The strategy has focussed on key areas of customer service and sought to achieve significant improvements through delivery of investment and improved field delivery performance. Where customer service is of primary importance we have focussed our own direct workforce on the activity, providing improved speed of service and direct control of reactive works. This will in particular provide improved performance in the resolution of supply interruptions.

The volumes of work required for the RIIO-ED1 period have been identified across all aspects of delivery and the resources required for delivery of the identified volumes have been reviewed. The most appropriate vehicle for delivery, direct labour or contractor, has then been reviewed bearing in mind service levels, volumes of work and costs, and the optimum model at this time confirmed and is to be implemented through the run up to RIIO-ED1, if not already in place. This model is being co-ordinated with the workforce renewal programme to deliver an optimised resource structure. The intention is to successfully combine the benefits of having both a direct labour organisation and contractor resource whilst minimising any associated drawbacks with these same models. In so doing we are applying the most appropriate delivery method to activities line-by-line to achieve a robust and efficient delivery model.

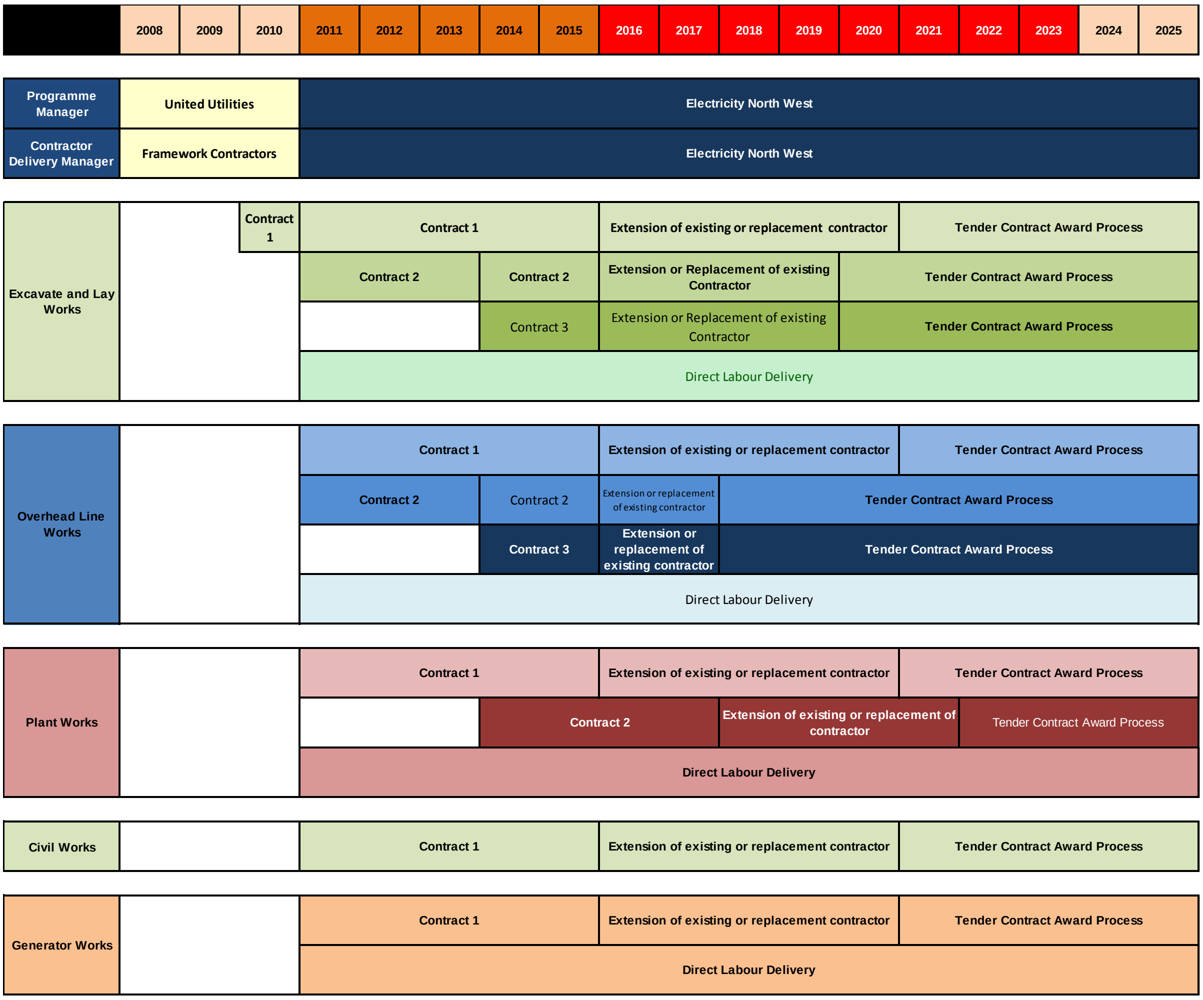
In addressing the RIIO-ED1 programme of work we have sought to achieve high levels of efficiency in the delivery programme. Our preparation work has included actively seeking to identify upper quartile levels of efficiency across the whole span of delivery requirements. We have then sought to achieve upper quartile cost performance from a total cost perspective across the breadth of our RIIO-ED1 proposals. The level of detail considered has been set out at individual fault types and individual Ofgem defined capital programme unit rates and their sub categories. This has been a fundamental review of the programme and has resulted in the building of a focussed and clear delivery structure. This has required some modifications to our operational structure, some of which have already been implemented and further changes are planned as we move towards and into RIIO-ED1. These changes have facilitated a very competitive proposal to be submitted from a delivery cost perspective and continual focus on output delivery, cost performance and monitoring from our delivery team.

In reviewing our contractor delivery structure moving into DPCR5 we moved away from large partnering style contractor contracts, which were shared with United Utilities. We reviewed the works we require and moved to Tier 2 delivery contractors who had the capability to deliver the works largely with their own resources within their areas of business expertise. This movement resulted in a small increase in the number of contractors being employed in delivery; however it has further reduced the levels of contractor margin and the associated overhead costs incurred.

The change also further reduced the management chain between with the contractor field force, improving the speed of management control in place. The contract structure was designed to reflect best practice available in the market with key frameworks for excavation and lay, overhead line and civil works being put in place. Major projects have been procured separately from the market and have continued to provide additional efficient delivery resource to the business. We may look to implement a Rising Lateral Mains framework contract in due course, following clarity of volumes and programmes of work, if we consider this will offer commercial or service level benefits.

This innovative and simple structure has been very successful in delivering reduced contractor costs and in providing resource to the business. We therefore have proposed to continue this delivery structure into RIIO-ED1. To continue to develop our capability and efficiency we are seeking to further improve the delivery options by improving the efficiency of the overall work force, both the direct labour and the contractor resource, their co-ordination and focus through further improvements.

The contracting strategy and structure is shown on the graphic below, including the transition from major framework suppliers to elemental activity frameworks. We have indicated where existing contractors are in place and where this arrangement may be extended or replaced by other contractors where we consider improved service or lower costs may be obtainable. The graphic also indicates where we will seek to tender contracts for future works within RIIO – ED1. These replacement processes are intended to be staggered through the programme period to allow the Procurement Team resources to address them individually, minimising team resource levels needed and allowing team focus on the services being sought.



In calculating detailed activity unit cost rates we have considered the volumes and selected the best programme delivery methods. ‘Bottom up’ detailed pricing of relevant activities has been undertaken and includes consideration of all the following cost elements:

- Study of typical site requirements.
- Value management review of activity
- Review of specific material required.

In the detailed calculation we have then included for the following aspects of direct costs:

- Labour costs
- Contractor Delivery costs
- Electrical Material costs
- Electrical Plant costs
- Construction Materials costs
- Operational activity costs

We have not allowed the introduction of permitting arrangements and other costs associated with recent or impending implementation of the Traffic Management Act to affect contractor rates.

Where suppliers or contractors are the selected delivery resource we have sought to ensure we are using market tested supplier and contractor costs within our calculations. Across the breadth of our proposals our Procurement teams have worked, over recent years and in the preparation of our RIIO-ED1 plan, to ensure all major spend areas are competitively tendered on a regular basis and in line with European Procurement legislation. For network related activities, covering both construction activities and materials, over 95% of expenditure is procured through long term, market tested frameworks or project-specific tendering. The following table documents the higher value contracts, illustrating that our current contractual terms provide coverage into the RIIO-ED1 period. These costs are included within our proposals at the market rates established.

Category	Contract	Annual Value (£m)			RIIO ED1							
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Construction	XD5 Constuction Frameworks	60.0	4	5	E	E	E	E	E	1	2	3
	Project Tendering	28.0	Individually Tendered									
Electrical Equipment	Cable (LV,11 & 33kV)	12.0	3	E	E	1	2	3	E	E	1	2
	11kV Switchgear	3.3	1	2	3	E	E	1	2	3	E	E
	Cable (132kV)	2.0	1	2	3	E	E	1	2	3	E	E
	HV Automation Contracts	2.0	1	2	3	E	E	1	2	3	E	E
	Distribution Transformers	1.9	3	E	E	1	2	3	E	E	1	1
	Primary Transformers	1.7	2	3	E	E	1	2	3	E	E	1

Key:
Current contractual coverage
Forthcoming framework period

Examples in which our procurement approach has generated clear commercial advantages include the following:

Bredbury 132kV Switchgear Renewal – Market stimulation to encourage new entrants, together with optimisation of work packaging options has generated a commercial benefit £4m (30%) when compared to the traditional sourcing route.

Distribution Switchgear – Use of volume banded pricing together with optimisation of product allocation within a dual sourced contract delivered annual savings of £200k (14%), as well as enhancing supply chain resilience.

ANNEX 7: DELIVERY STRATEGY

Electricity North West Limited
Registered Office:
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WA3 6XG.

Registered no: 2366949 (England)

Contents

1. Executive Summary

We have conducted a review of our delivery strategy to ensure that we can deliver the RIIO-ED1 business plan efficiently. Customer service is at the heart of our delivery strategy for RIIO-ED1. The strategy will achieve significant improvements through changes in the delivery of investment and improved performance in the field. An end-to-end review has enabled us to change how we are organised, optimising service and cost whilst ensuring the delivery of our obligations.

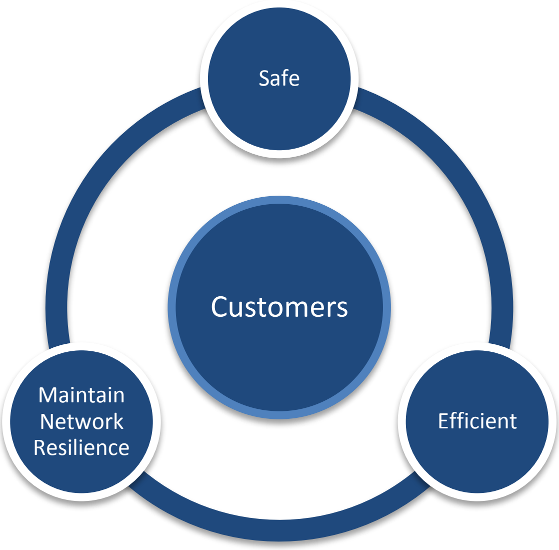
Efficient delivery requires a well-defined programme with clear scopes of work, optimised delivery routes and robust performance management. These conditions have all been achieved in RIIO-ED1. For the entire RIIO-ED1 programme, we have identified the upper quartile levels of efficiency for individual fault types and individual capital programme activities and their sub categories. These upper quartile levels have been used as internal benchmarking targets. For each activity type we have determined a delivery route that achieves the benchmark level or better. We have used a resource analysis tool to determine the optimum levels of resources required in each area. We are implementing several significant performance improvement programmes focussed on improving the productivity, efficiency and service levels of our in-house delivery organisation. The contracting strategy is tailored to fit the delivery model, largely supporting the Capital Programme and contractor delivered elements of our fault response service.

This annex provides an overview of the delivery strategy and resource modelling conducted as part of the business plan development. It also summarises our approach to maintaining flexibility in our resources provision to enable us to react efficiently to different emerging scenarios.

2. Delivery Strategy

2.1 Customer focussed

Our vision is to be the leading energy delivery business. To achieve this we have focussed on creating a delivery strategy with customer service at its heart. The strategy seeks to achieve significant improvements in performance through changes in the delivery of investment and improved performance in the field. We focus our own direct workforce on key customer activities. Using our own workforce improves the speed of service and ensures the direct control of reactive works. This provides improved performance in the resolution of supply interruptions – our customers' primary concern.



The delivery strategy provides our customers with a safe, reliable and efficient service.

Throughout the delivery chain, from procurement to delivery in the field, we have targeted improved customer service and efficient delivery to ensure value for customers. An end-to-end review has enabled us to change how we are organised, optimising service and cost whilst ensuring delivery of our obligations.

2.2 Continual improvement

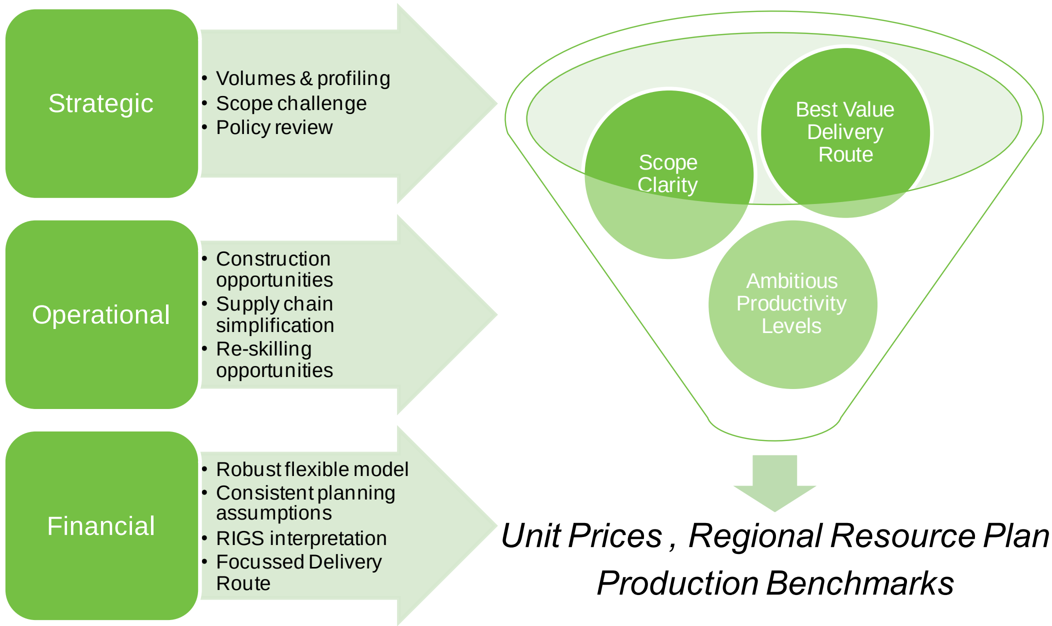
The delivery strategy is focussed on supporting our proposals for RIIO-ED1. The existing delivery model provides a platform on which to build further improvements in customer service, delivery capacity and delivery efficiency.

Significant changes to the delivery model have been embedded within our business over recent years, improving efficiency and operational control. We will continue that development process to generate further improvements in customer service and delivery efficiency.

3. Delivery Model

Efficient delivery requires:

- a well-defined programme with clear scopes of work
- optimised delivery routes
- robust performance management



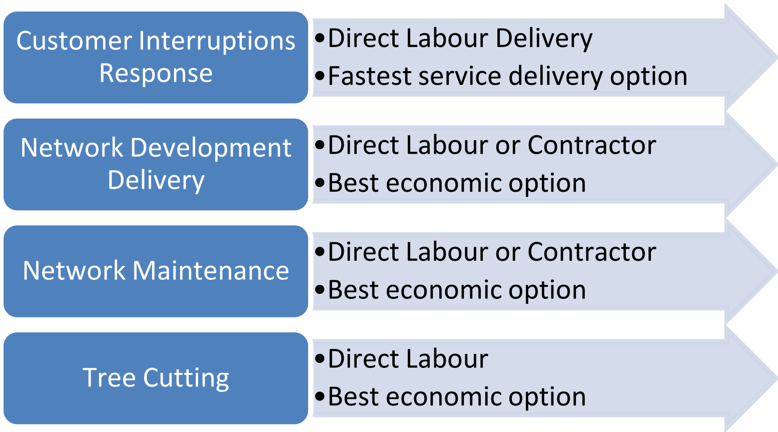
3.1 Comprehensive RIIO-ED1 plan

Assessing stakeholder and network needs for RIIO-ED1 has given us a clear view of the volumes and scope of work to be delivered. We have been able to share many insights of the scale and work mix in the RIIO-ED1 programme with our supply chain. This has enabled us to understand the resources available in the market and to market test to determine the most competitive rates available.

3.2 Best Value Delivery Route

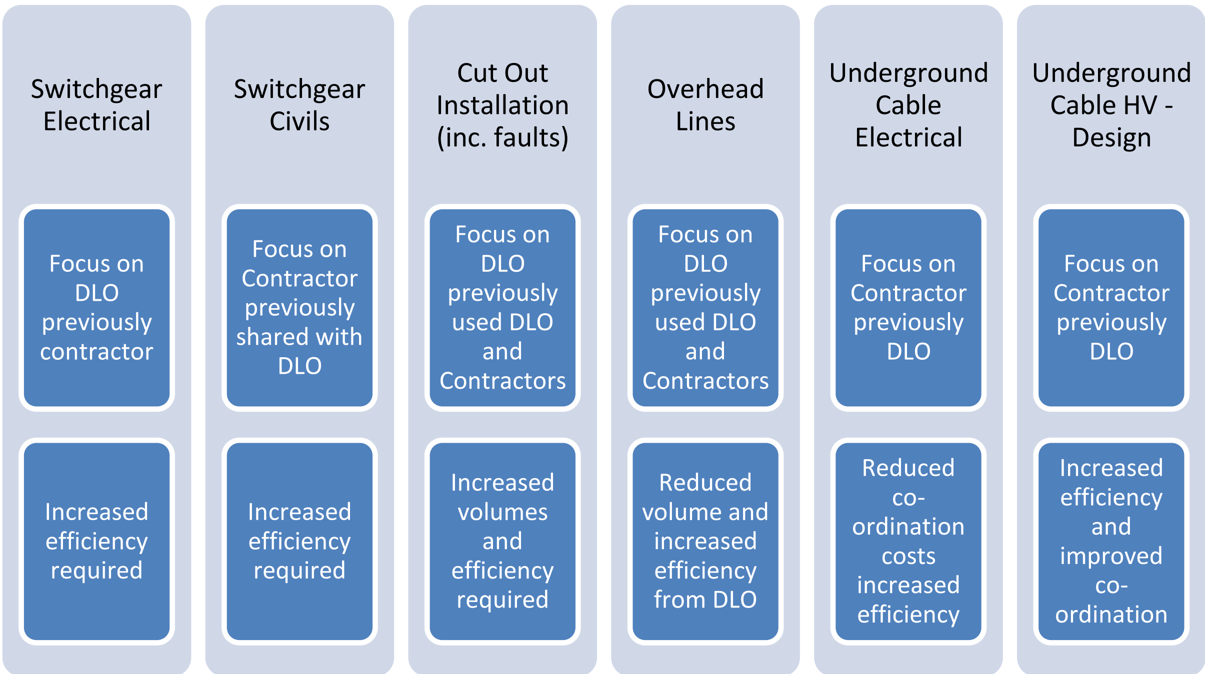
We have identified the upper quartile efficiency levels for individual fault types, individual capital programme unit rates and their sub categories for the entire RIIO-ED1 programme. These upper quartile levels have been used as internal benchmarking targets. For each activity type we have determined a delivery route which ensures that our entire programme can be delivered at upper quartile costs.

For every activity covered by the delivery strategy we have reviewed the options available to us with the simple principles identified in this section and set out graphically overleaf. The model is purposefully simple and effective with clear decision parameters. The key driving principles, established by our strategy, are that our direct labour force will focus on key customer service activities, maintenance works and some network investment work where self delivery is commercially efficient.

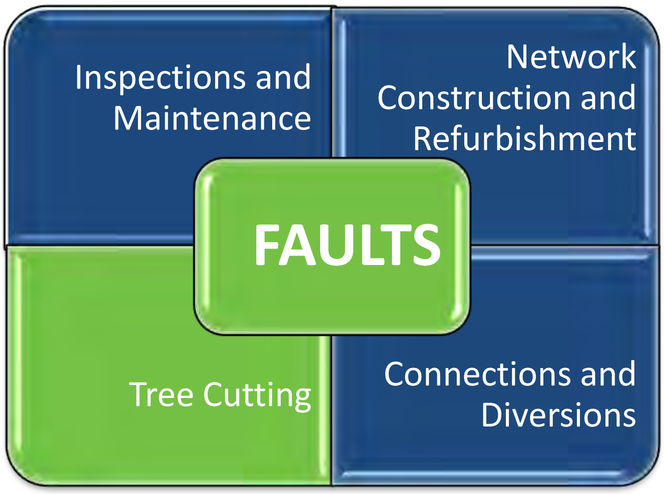


With a clear understanding of forecast activities and work volumes the most appropriate option of direct labour or contractor resource has been selected bearing in mind service levels, volumes of work and costs, and the optimum model identified. Where changes from current practice are required, these will be made in the last two years of DPCR5. This model is being co-ordinated with the workforce renewal programme to deliver an optimised delivery resource structure. The result will successfully combine the benefits of having both direct labour and contractor resources. This process has also targeted a simplified supply chain.

The defined delivery model will offer increased efficiency and improved customer service. There are many changes required to be implemented within the current delivery model to achieve these outcomes. These are summarised below together with explanatory notes where relevant.



Our delivery model strategy retains a core of direct labour for reactive customer work and tree cutting with flexibility provided by contractors for other investment areas. The minimum level of DLO (Direct Labour Organisation) is therefore derived from the level of standby resource needed, the level and types of faults anticipated, volumes of overhead line, plant and cut outs works required, together with maintenance volumes, including tree cutting. There is further detail later in this appendix setting out resource implications.This ensures security of fault response, retains and secures key skills within Electricity North West and provides efficient cost delivery whilst maintaining flexibility for the business.



Faults

Fault response and repair is the cornerstone of the resource plan. This will be resourced using our direct labour force. To calculate the resource requirements for faults we assessed the 24/7 service (minus daily Troublecall) requirements. Troublecall costs were developed through a bottom-up assessment which provided a “base price” for “perfect” faults. This was translated into target prices for the remainder of DPCR5 and RIIO-ED1. Additionally, we will seek to maximise the use of innovative technologies to facilitate fault location and optimise our activities and resources.

Tree Cutting

Tree cutting will be delivered by the direct workforce which has already placed Electricity North West in a UQ position when compared to other DNOs. The strategy of in-house delivery has assisted in managing and meeting our customers’ expectations, delivering a higher volume of cutting at an efficient cost per span. Tree cutting at EHV can additionally be supported by overhead transmission linesmen.

Inspections and Maintenance

Inspections and maintenance delivery is focused on the use of direct labour to deliver technical works, electrical maintenance and protection maintenance (with associated condition inspections). Transmission jointing, oil mechanics and linesmen teams will be resourced to manage faults with productivity maintained by delivering capital works at low fault times.

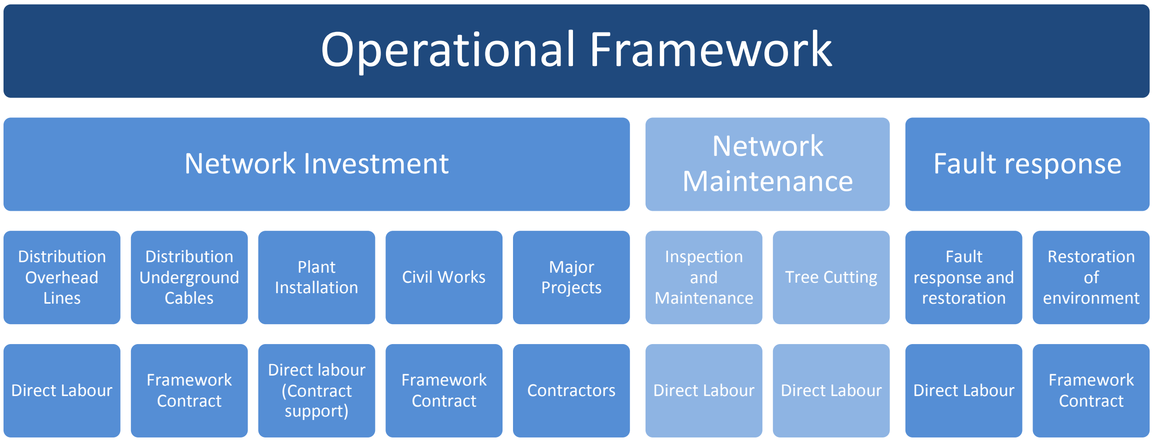
Civil maintenance activities will be delivered through a small in-house management team using specialist framework contractors for ad-hoc repairs and routine activities such as weed and clean, an approach that will help us achieve high levels of cost efficiency.

Specialist civil inspections, tunnels, bridges, asbestos etc will be delivered via subcontractors with appropriate skills and authorisations.

For overhead inspections (Towers & Wood Pole) we have the option to deliver with either direct workforce or contractors allowing flexibility in the programme to improve productivity.

Network Construction and Refurbishment

The mix of work between Contractors and direct labour has been optimised using our resource analysis tool. We have established over recent years a robust and efficient delivery framework which, as depicted below, sets out how the available resources are organised.



For high volume activities we have established framework agreement with specialist contractors in their fields. These frameworks set out robust service standards from health, safety, quality, speed of service and cost perspectives. Our tendering and negotiations with contractors ensures competitive cost levels are maintained and delivered through the framework agreements. Framework and tendering arrangements are determined by the type of work, for example major projects will be packaged and individually tendered to secure delivery costs at below framework contract levels. Improved direct labour productivity and focus on key areas of the programme will result in upper quartile unit cost delivery being achieved. More detail is provided in Annex 6 – Procurement Strategy.

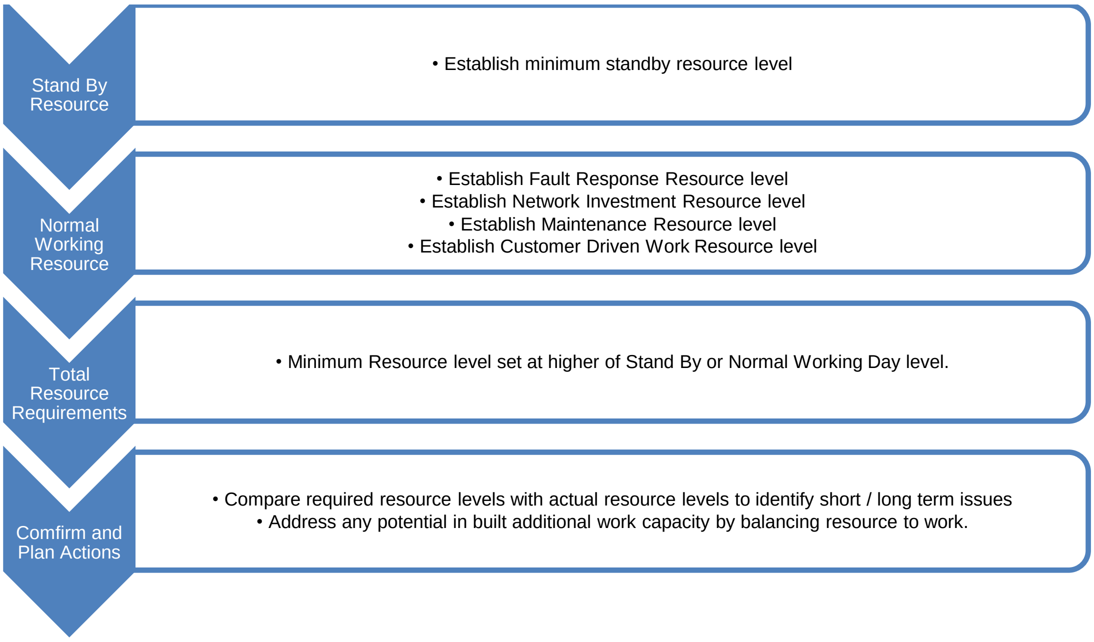
3.3 Delivery Resource Analysis

We have developed a resource analysis tool for our direct delivery teams. This model allows us to compare scenarios based upon the estimated volumes of activity required and the efficiency levels targeted. We have used this tool to determine the optimum levels of resources required in each area of the operational delivery team. We are therefore able to identify and manage required resource levels across the delivery programme. We can also use the tool to assess the impact of any changes or events that occur in the delivery plan on those resource levels.

These resource levels have been compiled following a thorough review of all the following aspects of the delivery activity demands within secondary networks:

- Fault response during normal working hours
- Fault response outside of normal working hours
- Asset replacement activities
- Asset refurbishment activities
- Customer connections delivery requirements
- Customer advice requirements

The resource analysis tool has built in logic that follows the delivery model we have established. In principle the following steps are followed to establish minimum required direct labour resource levels.



This resource modelling allows us to understand and flex our resources through the ED1 period, whilst maintaining the efficiency of the programme of works. This analysis tool allows us to understand the potential consequences of changes in advance and therefore significantly improves the capability of the organisation to flex and manage any challenges encountered along the way. The actual impacts on our resource levels are summarised in section 3.4 below.

3.4 DLO Resource Requirements

We are currently forecasting a modest increase in our direct delivery resource levels over the period of RIIO-ED1 (approximately 50 staff). This increase is required to resource the future in-house delivery of cut-out replacement works, primarily associated with smart meter roll-out. There are also changes required to resource specific skill sets, but we will manage this through the retraining and recruitment of staff in DPCR5 and in the early years of RIIO-ED1 to minimise any overall impact.

We have also identified a number of retraining and up skilling requirements to support key project areas including:

- Training jointers to carry out fitting duties associated with plant projects
- Training linesmen to collect quality inspection data
- Multi skilling linesmen to support out of hours jointing stand-by provision in some areas

The table below highlights the projected changes in staff numbers for secondary network delivery. This is the key area for the efficient utilisation of our direct delivery resource. As the plans are developed, there may be modifications resulting from the network investment programme designs and actual fault numbers. We will look to introduce multi-skilling of jointers to mitigate the increase forecast in fitters and train linesmen to collect network data to support a more efficient end-to-end process. At present, there are no significant changes in delivery staff skills or overall resource volumes anticipated. This base level requirement is then fed into our training and workforce renewal programme which factors in the impact of an aging workforce.

Trade or Skill	Forecast Resource	Current Resource	Comment
Engineer	102	92	Support peak requirements with Contractor
Fault Technician	47	47	Seeking to improve fault response service level
Electrical Jointer	180	184	Potential retraining as fitter.
Overhead Linesman	108	108	Reduction in contractor support
Fitter	26	13	Support peak requirements with Contractor
Cut-out Jointer	49	0	Dependent on Smart Meter driven volumes
Total	**541**	**479**	Main driver is increase in cut out jointers

3.5 Contractor Strategy

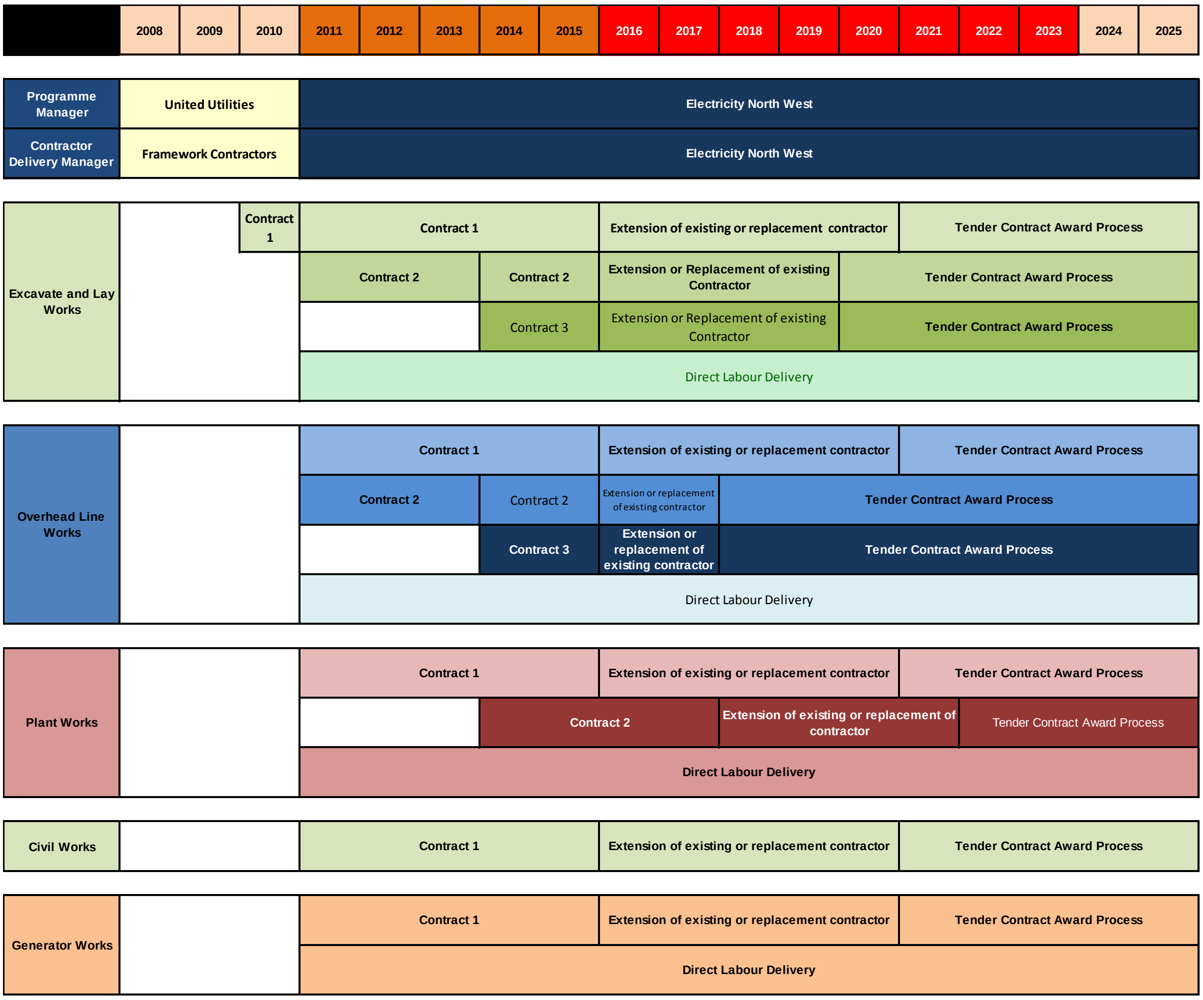
The overall Contractor Strategy is designed to map onto the operational delivery framework set out earlier in this Annex.

In reviewing our contractor delivery structure moving into DPCR5 we moved away from large partnering style contractor contracts, which were shared with United Utilities. We reviewed the works we require and moved to Tier 2 delivery contractors who had the capability to deliver the works largely with their own resources within their areas of business expertise. This movement resulted in a small increase in the number of contractors being employed in delivery; however it has reduced the levels of contractor margin and the associated overhead costs incurred. The change also further reduced the management chain to the contractor field force, improving the speed of management control.

This innovative and simple structure has been very successful in delivering reduced contractor costs and in providing resource to the business. We therefore have proposed to continue this delivery structure into RIIO-ED1. The contract structure is designed to reflect the actual resources available in the market with key frameworks for excavation and lay, overhead line and civil works being put in place. Major projects have been procured separately from the market and have continued to provide additional efficient delivery resource to the business. We may also look to implement a Rising Lateral Mains framework contract in due course, following clarity of volumes and programmes of work, if we consider this will offer commercial or service level benefits.

The overall contracting strategy and structure is shown on the graphic below. The previous transition from major framework suppliers to elemental activity frameworks is also indicated below. We have indicated where existing contractors are in place and where this arrangement may be extended or replaced by other contractors, if we consider improved service or lower costs may be obtainable. The graphic also indicates where we will seek to tender contracts for future works within RIIO–ED1. These replacement timings are intended to be staggered through the programme period to allow the Procurement Team resources to address them individually, minimizing team resource levels needed and allowing team focus on the services being sought. This also minimizes contractor delivery risk by staggering contractor replacement through the period rather than having a major change of all contractors at the same time.

The graphic overleaf terminates notionally at 2025 for illustration purposes. In reality all contracts to be let will be considered individually and may continue beyond this date. Individual contracts will be set at contracts lengths determined to suit several factors, including: being of sufficient length to be attractive to the contractor market encouraging competitive tendering, protection of continuous service over a period of years allowing, security of service, improved service and efficient operations to be developed, options on length of contractor (extension periods) may be incorporated to build in flexibility of period to allow for external market changes, end of contract if service levels are not acceptable, and also to allow overlapping periods of contracts to reduce impact of several contractors changing at the same point of time.



3.6 On-going DLO Performance Management

Through the regulatory periods of DPCR4 and DPCR5 there has already been considerable change undertaken within our delivery model. This has resulted in significant improvements in delivery capacity, customer service and reductions in cost of delivery. The improvements already implemented have been further refined and developed into our RIIO-ED1 proposals and the overall philosophy followed remains the same.

We are implementing several significant performance improvement programmes focussed on improving the productivity, efficiency and service levels of our own in house delivery organisation. Examples of the initiatives and projects already underway to improve our efficiency levels include the following;

1. Front line management effectiveness; improving delivery team performance
2. Simplified delivery routes; allowing clarity of performance data for delivery route
3. Management information improvement; allowing closer and faster output management
4. Fault response improvement programme; targeting reduced cost and faster delivery
5. Optimized delivery route options; commercially most advantageous option
6. Scheduling process improvements programme; increasing team productivity

3.7 Delivery Resource Flexibility

We have considered the need to build into the delivery plan the ability to flex resource availability, providing security of resource provision whilst maintaining efficient delivery. These key factors require careful balancing as they are often in conflict with each other. As a result the Secondary Network Delivery model is based on utilising the current direct labour resources largely in their current form, with more focus on customer reactive and maintenance works. A small increase in resource over the RIIO-ED1 period is required to undertake the additional work needed by the smart meter initiative. The balance of work will be completed by external contractors, procured through either framework arrangements, or for larger projects, via a formalised tender. The approach of undertaking the additional volume by utilising external contractors is appropriate as we anticipate there will be sufficient flexibility in the market at the commencement of the price control period.

Within the Major Projects arena we have set out to deliver these through individually tendered projects. This provides additional resources at highly efficient cost levels with an ability to flex resource levels up or down at relatively short notice in line with planned projects. Our only area of concern is that some specialist resources may become limited in a stretched market and as a consequence command a premium price. It is therefore essential that we continue to monitor the market to determine if this scenario is developing. If necessary we will initiate further procurement activity, to secure the appropriate contracting resource to ensure we continue to deliver in line with the business demands.

We have also considered the potential requirement to deliver significant project support to the Regional Nuclear Programme. The intention here would be to form a specific ENWL project team to manage the design, programming, health, safety, quality and programme of the works. We would contract the works to appropriate major electrical and engineering contractors as required by the project demands. The required works and programme will be considered in detail in due course as there are several contracting models that may be appropriate. This method of planning and delivery will provide the opportunity to deliver the project on time and cost whilst minimising any impact to the normal operations of the business.

ANNEX 8: DECC SCENARIOS

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Contents

1. Executive Summary

1.1 Background

In order to complete our expenditure forecast we have considered the regional economic forecast for our operating area and likely changes in customer behaviour driven by the wider context of the UK fourth Carbon Budget Plan that seeks to reduce CO_2 emissions by 35% (from 1990 levels) by 2023 and by 80% by 2050.

The Government, through DECC, has set out four potential scenarios that lead to the delivery of the CO_2 emission reduction targets. These are detailed in 'The Carbon Plan: Delivering our low carbon future' (December 2011) and are summarised below:

DECC Scenario		Heat Pump adoption	Electric Vehicle take up	PV take up	DSR take up
Low - Purchase of international credits	4	Low	Low	Low	None
Medium - High abatement in low carbon heat	1	High	Medium	Medium	None
Medium - High abatement in transport and bio-energy	2	Medium	High	Medium	Medium
High - Focus on high electrification	3	High	High	High	None

These scenarios all envisage greater usage of Low Carbon Technologies (LCTs) such as electric vehicles and heat pumps and also varying levels of energy efficiency and customer participation in commercial options such as Demand Side Response (DSR) (where customers receive a financial incentive to vary the time at which they use electricity).

LCT devices will inevitably increase the demand for electricity, with a doubling of demand by 2050 possible; however there is significant uncertainty as to when and where the increase in demand will materialise.

In formulating our investment plans we have undertaken extensive modelling of these scenarios and included other factors such as energy efficiency, the likely increase in distributed generation particularly at domestic customer level and the benefits of the new smart grid and smart meter technologies now emerging from our innovation programme.

1.2 Forecasting Outcome

The total additional forecast costs of the DECC scenarios are as follows:

£m 2012-13 prices	Increment above Scenario 4 (Low)		
	1	2	3
TOTAL	106.3	129.4	152.8

2. Best View of LCT Uptake

In assessing which of the scenarios is most likely to represent the uptake of LCTs for our region we have engaged widely with our regional stakeholders. This work has indicated that the general outlook for economic activity in the North West is likely to be lower than the national average and history indicates that the region will emerge from the recession more slowly than others such as the South East.

We are also aware that government funded stimulus such as the Domestic Renewable Heat Incentive have been set at a level that favours off-gas grid areas. As the North West has a high degree of gas grid availability and a relatively low level of all electric high multiple occupancy buildings we consider it likely that uptake of such incentives will be comparatively lower than in other regions.

The combination of these economic drivers and stimulus packages indicates that LCT take up will be lower in the North West than the national average. As such we have concluded that the DECC Low scenario is the most probable estimate for RIIO-ED1 for our region.

In order to produce a more accurate asset investment plan we have subdivided the overall regional LCT forecast into sub-regional adoption levels. The Tyndall Centre (part of the University of Manchester) was commissioned to advise how DECC's forecast of heat pump penetration would be likely to map to each local authority (LA) area within our operating area. In addition, they advised how this penetration may be clustered. This latter clustering factor is critical to determining the timing and location of investment needs.

Similarly, the Transport Research Laboratory was commissioned to advise how DECC's forecast of Electric Vehicle (EV) penetration would be most likely to map to each local authority (LA) area within our operating area, again with associated clustering assumptions.

In designing the delivery model for our business plan we have been mindful of the need to be able to flex resources in the event that LCT adoption rates are higher than anticipated. Our delivery plan, detailed in Annex 7, shows how we will be able to increase our contract resources and flex our less time critical investments to accommodate any reasonably foreseeable level of LCT adoption up to and including the highest of the DECC scenarios. The same approach would be applicable for a higher than forecast level of regional economic activity.

3. How We Have Built Up Our Forecast

Our low carbon technology scenarios are based on DECC equivalent scenarios and align with LCT volumes predicted by the Transform model. The table below details the total incremental LCT volumes for our region forecast by technology type over the RIIO-ED1 period.

	DECC scenario			
	1	**2**	**3**	**4**
Heat Pumps	86,475	65,889	86,475	45,303
EV slow charge	38,390	60,133	60,133	12,891
EV fast charge	104,287	159,166	159,166	34,146
PVs (MW)	757	757	941	61

Our approach to calculating the low carbon scenarios is as follows:

- The demand forecast is based on a start point of winter 2011 demand (ie Q3 and Q4 2011-12).
- From the start position we add our base economic forecast which is based on the CEPA economic forecast for our region as at May 2013.
- For each of the four DECC scenarios we then add a supplemental investment forecast to reflect the specific LCT adoption rates for each scenario.

This produces four demand forecasts for all of our network assets (one per scenario), this demand forecast is then compared against existing network capacity and where capacity is exceeded an intervention need is identified. The comparison of forecast demand to capacity at the specific asset level is expressed in the form of a Load Index (LI) with an LI of 5 indicating a need to carry out some form of intervention.

The overall reinforcement costs forecast as resulting from each DECC scenario are as follows;

£m 2012-13 prices	**DECC Scenario**			
	4 (Best View)	**1**	**2**	**3**
EHV & 132kV Reinforcement	39.3	42.9	42.9	53.1
LV & HV Reinforcement	49.5	137.4	159.7	163.7
Sub-total	**88.9**	**180.3**	**202.6**	**216.8**
Fault level	14.5	14.5	14.5	14.5
TOTAL	**103.3**	**194.8**	**217.1**	**231.2**

Annex 21 gives more details of our reinforcement forecasting methodology and the following sections discuss the results in more detail.

3.1 EHV & 132kV reinforcement

Our Grid and Primary (G&P) reinforcement programme addresses reinforcement requirements of the 132kV and 33kV networks, inclusive of High Voltage (11kV and 6.6kV) switchgear at primary substations. This programme is a forecast of specific network issues including identified LIs, and P2/6 compliance for each scenario.

We have forecast demand on the network as a baseline forecast and an incremental forecast. For the baseline forecast we have used CEPA's projection of base economic activity. The incremental forecast recognises the impact on demand of the DECC four scenarios. These forecasts are applied to the network to identify issues requiring reinforcement.

Individual issues at 33kV and 132kV sites have been individually designed and priced for each scenario.

Pricing has been undertaken against the optimum design scope per scheme, each of which is appended to our business plan submission. Pricing of the component elements is based on our latest unit costs.

Our analysis of smart grid and smart meter benefits indicates that a 'smart discount' of 20% is attainable when the latest technologies emerging from indusry innovation work are applied. We have therefore priced our G&P programme on a traditional solution scope of work but discounted across the board by 20%.

3.2 LV & HV reinforcement

Our Secondary Network (SN) reinforcement programme addresses the reinforcement requirements of the High Voltage (HV) and Low Voltage (LV) networks. Although the network is studied to identify issues, the uncertainty surrounding where demand will materialise at these voltage levels means that the programme is specified as an intervention volume count priced with appropriate modular solutions (HV and LV) which in turn are comprised of efficient unit costs.

The Smart Grid Forum Transform model has been used to calculate secondary network reinforcement costs for voltage and thermal issues. Secondary network reinforcement driven by power quality is not covered by Transform and our costs have been calculated using our Future Capacity Head Room (FCHR) model.

Pricing for those elements covered by Transform are from Transform. Pricing of any other elements is based on our latest unit costs.

Our work on the effect of sustained high current loads such as heat pumps shows that they are in general not compatible with looped service configurations. We have calculated the number of such devices that will drive unbundling of such service connections arrangements and included appropriate costs in our forecast.

We have assumed no change in the connection charging boundary for the purposes of this submission.

The circuit type assumptions within the Transform model are, out of necessity, based on average circuit parameters for that circuit type, together with typical loadings for an appropriate mix of property types for the circuit type. As a consequence of this methodology and the apportionment of commercial loads within the model, there is the potential for the model to marginally under or over estimate the current loadings on any one circuit. In the case of our network, the simplified assumptions in the model cause results that suggest that a number of existing high and low voltage feeders may be operating at the margin of the nominal permitted levels for voltage, peak thermal capacity or power quality.

The Transform model estimates that the work required to address these issues would cost around £250m. As no customer feedback or network data exists to suggest that such a problem exists on our network, we have not included this potential capital investment in our forecast.

3.3 Distributed Generation

Reinforcement costs associated with the connection of micro-level Distributed Generation (DG) at domestic properties have been determined using the Transform model calibrated against our internal model. All of the smart grid benefits forecast by Transform have been incorporated into our investment plan.

For commercial scale DG, we have used the central DG forecast for our region provided by DECC. We have assumed no change in the connection charging boundary for the purposes of this submission and hence reinforcement charges for shared assets have been calculated in line with current actual costs.

3.4 Fault Level

Our fault level programme is common across all scenarios and is driven by the background load and DG levels.

Further details of the fault level programme and its derivation can be found in Annex 21.

3.5 Other Costs

Although the majority of the additional costs associated with the DECC scenarios are related to network reinforcement work, there are a number of other impacts on the cost base:

- Additional indirect costs to support delivery of the reinforcement projects (project design, management etc.)
- Additional Remote Terminal Units (RTUs) to control and further automate and control the network together with further LV monitoring installations to increase real-time management capabilities
- Additional IT support costs to manage the increased RTU and LV monitoring equipment

All of the scenarios will require the deployment of additional secondary network RTUs to a greater or lesser extent. These RTUs are mandated by many of the smart solution sets and additionally will be required to confirm load/generation management effectiveness.

They will be deployed at distribution substations dependent on the rate of load growth in particular network areas. They will support all smart grid solutions including closed loop control systems, active voltage control, sensing and demand/generation systems.

We have assumed that the Low scenario will require the installation of an additional 50 units per year above what would have otherwise been required. The further increments relating to the other DECC scenarios are as follows:

	Increment above Scenario 4 (Low)		
	1	**2**	**3**
Count of units p.a.	125	125	250
Total	1,000	1,000	2,000
Unit cost	£5,500	£5,500	£5,500
Total cost	£5,500,000	£5,500,000	£10,900,000
Additional Control hardware	£1,500,000	£1,500,000	£3,500,000
Total cost	**£7,000,000**	**£7,000,000**	**£14,400,000**

The total additional forecast costs of the DECC scenarios are therefore as follows:

£m 2012-13 prices	**Increment above Scenario 4 (Low)**		
	1	**2**	**3**
Reinforcement	91.5	113.8	127.9
Operational IT	7.0	7.0	14.6
IT running costs	0.8	0.8	1.4
Project support*	7.0	7.8	8.9
TOTAL	**106.3**	**129.4**	**152.8**

* This category is reported as 'Closely Associated Indirects' to Ofgem and includes activities such as design and project management

4. Summary

The nature of the new Low Carbon Technologies we anticipate will be connected during the RIIO-ED1 period will create issues not previously seen in any significant volume on the distribution networks.

Our work with industry partners through the Smart Grid Forum and bodies such as the Strategic Technology Programme has enabled us to put in place an innovative and efficient business plan that is able to flexibly respond to any foreseeable LCT and economic activity level.

The final technology deployed on any given intervention need will be determined by CBA analysis as the need arises. However the portfolio of solutions developed to date allows us to meet the forecast challenges at a much lower cost than traditional solutions.

ANNEX 9: VULNERABLE CUSTOMER STRATEGY

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Contents

1. Introduction

We are committed to supporting our customers in all situations where they may be vulnerable. To do this we need to understand who and where they are, and to know the most appropriate way to anticipate and meet their needs. Our aims are to ensure that our services are available and made accessible to all customers equally, regardless of their personal circumstances, and to embed these values throughout all aspects of our business.

This Annex describes our approach to developing our services for Vulnerable Customers, and in particular those who are included on our Priority Services Register (PSR) or may be described as Fuel Poor. Our strategy, which will continue through RIIO-ED1, is to establish a network of contacts with other organisations and agencies that have similar interests to ourselves as service providers, or have areas of expertise that we can use to improve our understanding of vulnerable customers and their needs. We will continue to develop our services based on this collaborative approach.

We have developed a series of specific proposals, which sit within four broad categories:

- To **promote the Priority Services Register** effectively, to ensure that it is used by all those who can benefit from it.
- To establish an effective **contact strategy** with vulnerable customers, to ensure that the data we hold is regularly refreshed.
- To establish a comprehensive **data strateg**y for vulnerable customers, within the wider strategy for Customer Relationship Management.
- To **improve the services** we provide for vulnerable and fuel-poor customers.

Many of the proposals do not require the provision of additional resources; however we recognise that organisational changes, both structural and cultural, will be necessary to drive our strategic commitment to vulnerable customers. We have also identified a number of activities and proposals which do have cost implications; however we are not seeking any additional funding for our activities in this area. We believe that our developments across a broad range of customer service measures, including relevant stakeholder engagement, will drive sufficient incentive reward from the Broad Measure of Customer Service and the Interruptions Incentive Scheme to support these measures without a specific funding request.

The initiatives requiring investment are as follows:

- IT systems for Customer Relationship Management.
- Resilience improvements of networks supplying regional hospitals.
- Resilience improvements of networks supplying a high density of vulnerable customers.
- Welfare provisions for vulnerable customers.

The first two of these initiatives are planned to be started during DPCR5, incurring a cost to shareholders of £2 million and £0.6 million respectively.

2. Vulnerable Customers

2.1 Adoption of the British Standard

The relevant British Standard is BS 18477 “Inclusive service provision - Requirements for identifying and responding to consumer vulnerability”. The standard is designed specifically to help organisations to identify consumers who could be vulnerable or disadvantaged and to adapt their service to be inclusive and accessible to all. The standard uses the term “consumers” to be applicable across a broad spectrum of organisations. We propose to adopt this British Standard in order to provide us with the necessary level of consistency and guidelines to work from on behalf of our customers. This will ensure we consider our approach for all our customers who are faced with complex or urgent issues arising from a wide range of individual circumstances.

The standard defines vulnerability as:

”The condition in which a consumer is at greater risk of mis-selling, exploitation or being put at a disadvantage in terms of accessing or using a service, or in seeking redress.”

The standard encourages companies to identify and respond to consumer vulnerability and tackle issues such as providing responsible business practices and accessible systems. The standard:

- Sets out recommendations for identifying risk factors, such as ‘triggers’, and how to understand consumers’ circumstances quickly as well as the appropriate approach needed;
- Pulls together best practice in terms of how services are marketed, sold and presented (including billing) and the information requirements that different audiences or groups may be looking for; and
- Provides case studies and statistics that will hopefully highlight where bad practice has resulted in a negative result for both business and consumer.

The adoption of the BS18477 will help us to:

- Understand and adopt best practice in the identification and treatment of vulnerable consumers;
- Understand what our customers have a right to expect from us;
- Adopt fair, ethical and inclusive practices; and
- Increase the confidence that our customers have in Electricity North West.

By adopting the British Standard for vulnerable customers, all customers are covered by our promise to challenge our processes and behaviours to ensure that none of our customers are hindered in gaining access to our services or in seeking redress if things go wrong. This area is evolving and requires our continual focus and drive throughout RIIO-ED1. To ensure this focus we will establish a team to lead the business changes in these areas and engage with all relevant stakeholders.

We will develop our strategies for vulnerable customers to be consistent with Ofgem’s developing Consumer Vulnerability Strategy. We will work with Ofgem and others to review our Priority Services Register and in the development of best practice in this area.

2.2 Priority Services Register

We are aware that many of our customers have special needs or requirements, particularly when the power goes off. We maintain a Priority Services Register (PSR) of vulnerable customers and have teamed up with other partners such as the British Red Cross to offer enhanced services to these customers when they are without power.

We currently have in the region of 235,650 households on our PSR, categorised in line with the Ofgem guidelines. The Licence requirements relating to the PSR are set out in Appendix 1. Our adoption of BS18477 will mean that both the quantity and the quality of the data held on the register will have to be enhanced.

Priority services customers currently receive additional contact from our contact centre during power cuts or planned interruptions to keep them informed of the situation and likely time before power restoration, or to make arrangements for the British Red Cross to visit them. The information we currently provide on our website is in Appendix 2. In summary we will:

- Arrange for a telephone call to provide reassurance and advice regarding outages;
- Provide vital resources, including blankets, gloves and thermal mugs during outages;
- Arrange for a volunteer to visit with a hot drink;
- Arrange for trained volunteers to visit areas to provide extra support on a larger scale;
- Deploy a mobile unit during incidents; and
- Offer a password scheme for extra security and peace of mind.

We recognise that we need to do more for these customers and the following sections set out the key issues, the process and the plans for developing this aspect of our customer service.

3. Process and Key Issues

We aim to develop a flexible and inclusive service offering for all our customers, in particular ensuring that services are accessible to vulnerable consumers, giving them confidence that their needs can be met.

Our work to date has identified four key areas of focus in order to improve our services to meet the needs of vulnerable customers:

- To **promote the Priority Services Register** effectively, to ensure that it is used by all those who can benefit from it.
- To establish an effective **contact strategy** with vulnerable customers, to ensure that the data we hold is regularly refreshed.
- To establish a comprehensive **data strateg**y for vulnerable customers, within the wider strategy for Customer Relationship Management.
- To **improve the services** we provide for vulnerable and fuel-poor customers.

Our communication strategies in relation to vulnerable customers, both for promoting the service and for ongoing contact, are at the heart of the ongoing process for continual development of our plans throughout RIIO-ED1 and beyond. Our core strategy is to gain insight into the needs of groups of vulnerable customers by consulting with key agencies, and then to collaborate with them to deliver appropriate services. We fully understand that this approach cannot be used to override the needs of individual customers; however we believe that the pooling of information and expertise is key to developing a properly considered action plan.

We envisage that the enhancement of data will best be achieved by establishing a network of links with other organisations and targeting specific areas of customer data. For example, we are seeking to refresh our priority services data through relationships established with organisations having allied interests such as other network operators, councils and charities. This would be supplemented by the development of scripts for use by the contact centre to obtain relevant data directly from customers. This engagement is targeted to deliver the following:

- Provide the means for promoting the PSR to all our customers;
- Facilitate the regular refresh of the PSR data;
- Improve the data quality of our PSR;
- Enhance the services we provide to customers on our PSR; and
- Develop initiatives with agencies concerned with vulnerable customers to provide mutual support (eg to provide on-site support following loss of supply).

4. Promoting Our Services for Vulnerable Customers

We recognise that the data that we hold on vulnerable customers is in need of improvement in terms of both quantity (ie coverage of all customers who would benefit) and also quality (ie identifying the specific needs of individual customers).

We plan to address this issue by being more proactive in publicising the Priority Services Register, and in obtaining data from a number of sources. We have trained our customer-facing people to recognise potential PSR customers and, where this is the case, provide a proactive registration service. We will ensure that all our front-line people including our contractors are regularly trained in these aspects on an ongoing basis. We will ensure that our PSR customers are contacted a minimum of once every other year so that the information we hold is up to date.

In addition to publicising the PSR on our website, we have developed a contact strategy based on establishing a network of links with suppliers, other network companies, local stakeholders and agencies working with vulnerable consumers. Our strategy and services will be further enhanced through our contact with relevant stakeholders. We have contacted a wide range of stakeholders who work with customers of different stages of vulnerability, for example:

British Red Cross

We partner with the British Red Cross in order to provide customers with practical and personal support particularly if they are without power. The partnership provides us with invaluable insights into the needs of customers in this situation.

National Health Service

Knowing that health services are in contact with people at times of vulnerability, we have contacted the newly created Clinical Commissioning Groups (CCGs) in order to inform them of the services we offer customers. We aim to develop this relationship by inviting them to our external stakeholder panel to discuss our vulnerable customer strategy and developments going forward.

National Energy Action (NEA)

We are part of NEA's Business Support Group and have worked with them on various projects including the evaluation of our educational schemes to include fuel efficiency messages, and on a scheme in Stockport with the dual aim of lowering network load whilst helping to alleviate fuel poverty in the area. We also have an NEA representative on our External Stakeholder Panel to help guide and shape our policies with regards to vulnerable customers.

We plan to establish a working group with external agencies that will meet twice a year to review service delivery performance and examine opportunities to enhance it, utilising the feedback from our stakeholder engagement. We believe that by facilitating this working together in support partnerships we will improve knowledge on such customers and find shared innovative solutions. The strategy will drive a shared list of vulnerable customers and locations in the North West of England.

We are committed to working with all stakeholders on sharing information within the requirements of the Data Protection Act in order to improve the delivery of necessary assistance to customers.

5. Ongoing Contact with Vulnerable Customers

The circumstances of vulnerable customers can change, and it is important that we regularly refresh our data to maintain its value. We will regularly update data from the network of links established in our strategy for promoting the PSR, and also make regular contact with the PSR customers themselves.

We plan to contact all customers on the register once every other year to update details and confirm they understand how we can help. Our initiatives on customer relationship management will help us collect and respond to these differing priority customer needs.

More fundamentally, our systems and processes for managing customer interactions will have policies for identifying and handling consumer vulnerability embedded within them. We recognise that in order to respond to this challenge there will need to be a culture shift across the organisation. We are developing a programme in conjunction with the Mary Gober organisation that will deliver a culture of ownership and impact for 1,600 Electricity North West employees and our 400 strong contracting partners. The training will allow employees to focus on their areas of impact to improve customer service by taking ownership and removing blocks. The long term delivery programme is supported by an embedding programme that will be built into Electricity North West staff appraisal documents to challenge behaviours.

Our contact centre people will be trained to identify triggers for vulnerability and how to tailor appropriate products and services when any customer contacts us, for whatever reason. Other aspects of the programme will be rolled out to the whole workforce including our contractors, to ensure that the customer service objectives are tied in for all our people.

6. Customer Relationship Management and Data Strategy

6.1 Customer Relationship Management

We want to understand and perform for our customers with the same efficiency and effectiveness that we apply to looking after our network assets. This means making the most of the information currently available to us and looking forward to how that will be enhanced by future developments, both in our company and across the industry as a whole.

The introduction of Smart Meters, which will be rolled out from the beginning of 2015, will help us bridge a major gap in our customer information. In the longer term (towards the end of RIIO-ED1 and throughout RIIO-ED2) we see significant potential to improve customer service through enhancing:

- Customer communication and interaction;
- Network performance monitoring;
- Management of power outages;
- Provision of connections;
- Demand Side Response; and
- Management of losses.

Smart Meter data on its own, however, is only part of the answer. It will certainly help us understand our customers' interactions with the network better but we need to do more to understand their wider relationships with our business as a whole.

We recognise that Customer Relationship Management extends beyond the systems for holding data itself to how we obtain the data and how we use it. We anticipate that our relationship with our customers will develop over time and that in the future there will be greater need for:

- Anticipating customer needs and desires;
- Segmentation of the customer base, using multiple factors, leading to more personalised services;
- Proactive initiation of services using intelligent software; and
- Empowered employees who can resolve issues quickly, supported by well-informed management.

We believe that customer satisfaction scores will be seen as a key indicator of confidence in our business, and this will become increasingly important because trust will be a major factor in persuading customers to share information and collaborate in new service applications.

We expect that:

- Customers will increasingly expect offerings to be bespoke, personalised, or have the appearance of being tailored to their needs;
- Customer preferences and tastes will change more quickly; and
- Empowered customers will be increasingly confident in sharing their details in return for personalised and value-add services, but only on their terms and with organisations they trust.

Our vision is to hold all our customer data in one location, allowing us to offer a better more personalised service to our customers and creating a trusting relationship. Customer Relationship Management (CRM) will help us understand our customers' situations and experiences with Electricity North West by holding all the data in one location, which will benefit the customer in their interactions with us.

Our strategy is to use the example of vulnerable customers to drive the development of CRM for all our customers. We believe that if our CRM systems and processes are designed with the vulnerable customer in mind, then they will be fit for purpose in addressing the needs of the wider customer base.

For example, we have identified the need to be able to search for data by location and also by customer as we are not generally notified if a customer moves property. We also need the flexibility to record transient cases of vulnerability and report areas where there is high density of fuel poor. In the case of vulnerable customers it is essential to their quality of life that we record everything we learn about them and utilise this for future dealings with them.

6.2 Data Strategy

Although we hold a considerable amount of data regarding our network assets and connection points, our information about individual customers, their contact history and their requirements, is not currently sufficiently well embedded within the overall framework of data that we hold. Our strategy for Customer Relationship Management (CRM) is described further in Annex 18 IT Strategy.

We are currently developing the processes around which to build a Customer Relationship Management system. At a high level we see this as a means of providing better linkages between data that we already hold (suitably extended to pick up new developments), and new or refreshed data relating to individual customers. We recognise that in the future there will be both the need and the opportunity to hold significantly more data about our customers and their needs.

At an early stage of this project, plans are in place for improving the ease of access to data relating to the network usage of all our half hourly metered customers and linking it to network data, primarily as a network planning and reporting tool.

The next stage is the development of query and analysis tools designed to work with all the elements of data described below. An example of the benefits of this approach is our work to identify networks and substations providing supplies to high density vulnerable customer locations, in order to prioritise investment in resilience measures. Our aim is to make this form of analysis much easier to perform in the future.

The relevant data falls into four broad categories and could be held in different systems:

- Data relating to the connection point
  - Metering point Administration Number (MPAN)
  - Capacity
  - Low Carbon Technologies connected (Generation, Electric Vehicle charging point, Heat Pump etc)
- Charging/billing data
  - Consumption data
  - Data from Smart Meters
- Network and locational data
  - Geographic
  - Network connectivity
- Individual customer data
  - Contact information
  - Contact history

    - Vulnerable Customer details

Our plan is to complete the creation of the customer data repository in DPCR5.

7. Proposed Additional Services for Vulnerable Customers

We aim to develop a flexible and inclusive service offering for all our customers. Ofgem is rightly concerned that we do not assume responsibility for solving issues that extend beyond the scope of our business. However, maintaining and restoring supplies to our most vulnerable customers is our core business and we believe that our commitments to provide enhanced services in the future are a clear demonstration that we are serious in meeting the challenge.

We have proposals in the following areas:

- Network investment proposals for improving supplies to vulnerable customers
    - Improving the resilience of those networks and substations providing supplies to hospitals
    - Improving the resilience of those networks and substations providing supplies to high density vulnerable customer locations
- Welfare Services
- Automatic Payment of Guaranteed Standard Payments
- Fuel Poor and Off-Grid customers

7.1 Network investment proposals for improving supplies to vulnerable customers

We recognise that some of our customers are particularly vulnerable to loss of their electricity supply. For such customers, electricity may be required to power life-supporting equipment such as ventilators, oxygen concentrators, dialysis machines and other similar devices.

In addition to the existing priority services that we offer we are planning to invest in network infrastructure to ensure that any distribution transformers which provide supply to high numbers of vulnerable customers are resilient to HV fault events. In such cases it is expected that the supplies would be restored via an alternative supply, using network automation, thus significantly reducing the duration of power outage.

We have two specific initiatives for network investment on behalf of vulnerable customers:

7.1.1 Improving the resilience of those networks and substations providing supplies to hospitals

We have completed work to identify all hospitals connected to the high voltage network in our area. This has identified some 56 sites and it is proposed to invest in the network such that supplies can be restored to these locations by means of network automation in the event of a fault outage affecting the normal supply route. This investment will result in a significant improvement in the resilience of the network in these locations.

This investment is expected to cost £1.2 million. We intend to start this work in the current price control period and plan to address 50% of all sites by 2015 at a cost of £600,000. A further £600,000 will be invested during the early part of the RIIO-ED1 period. All work will be completed by 2017.

7.1.2 Improving the resilience of those networks and substations providing supplies to high density vulnerable customer locations

There are around 235,650 PSR customers connected to our network. These customers are supplied from a total of 13,360 individual distribution substations. Of these, 2,790 substations (supplying electricity to 69,500 vulnerable customers) will have remote control installed as part of ongoing quality of supply investments.

Of the remaining substations, it is our intention to fit remote control and commission network automation at all substations which meet qualifying criteria which combine the total number of vulnerable customers connected and the fault performance history for that substation.

Qualifying substations for this investment are those supplying 50 or more vulnerable customers which, when measured over the previous five year period, have seen two or more interruptions as a result of a higher voltage fault. The investment is intended to ensure that supplies can be restored from an alternative HV source in the event of a fault outage. The network restoration switching will be via automation systems thus significantly reducing the duration of any supply outage.

In total there are 87 distribution substations that satisfy the above criteria supplying electricity to just over 5,200 vulnerable customers. This investment is expected to cost £1.6 million. We intend to start this work at the start of the RIIO-ED1 period and it will take two years to complete.

7.1.3 Network investment proposals summary

In total we plan to invest £2.8 million in improving the network performance to vulnerable customers. This investment is based on well established methods and will result in significant improvement in the quality of supply for the most vulnerable of our customers.

The investment is summarised in the following table:

Initiative	Number of sites	Cost	Number of customers benefiting	Anticipated completion date
Hospitals	56	£1.2m	Not applicable	All work completed by 2017
Domestic vulnerable customers	87	£1.6m	5,262	

We are planning to commence this work in 2014 and complete up to half of it in DPCR5. As a consequence, we have included £1.4m to complete the programme in our RIIO-ED1 submission.

7.2 Welfare Services

We propose to offer other services to vulnerable customers to minimise the impact of supply interruptions on their lives through improved planning, coordination and communication regarding planned work, and more proactive communication and support during unplanned outages:

- We will provide an alternative supply for customers for planned interruptions or under fault scenarios over three hours where we cannot provide a reasonable time for restoration of the supply and where there is a defined medical dependency on electricity eg:
  - Nebuliser
  - Heart / lung machine
  - Kidney Dialysis
  - Oxygen Concentrator
  - Ventilator
  - Other medical dependency on electricity
  - Stair lifts
  - Restricted movement
- We will provide welfare and food provision for PSR customers off supply following a six hour period
- All connections applications for PSR customers will include a site visit if required by the customer to assist in the overall process
- All PSR Customers will receive 14 days notice of Planned Interruptions through face to face contact
- Prior to any planned interruption, the volume of PSR customers will be assessed to determine whether alternative facilities would be required. We will make proactive contact with all PSR customers affected by a fault within half an hour to understand the level of support required
- We will offer proactive contacts to all customers as reminders for planned interruptions, and providing supporting helpful tips on how to manage through a power cut
- We will develop information packs for dealing without electricity, with tutorials to be made available through our stakeholders such as:
  - Housing Associations
  - Schools
  - Youth Workers
- We will ensure our communications are available through all media channels in accessible formats
- We will make it easy to do business with us, by being transparent and not using jargon
- We will send a welcome letter and information pack to every new customer joining the Priority Service Register

7.3 Automatic Payment of Guaranteed Standard Payments

Guaranteed Standards are standards of customer service backed by a guarantee - customers receive a payment, either directly from us or through their electricity supplier, if we fail to meet these standards. The standards are the same for all distributors.

Guaranteed Standard payments are there to ensure that where our performance falls below the minimum level expected, the customer is given an appropriate level of payment.

For some failures, customers are required to claim a payment though it is recognised that many customers will not be aware of the existence of the standards and whether a payment is due in particular circumstances. In RIIO-ED1, we will make payments to customers on the Priority Service Register automatically. In addition, we have addressed the issue of automatic payments as part of our stakeholder engagement process and as a result we propose to inform our customers better of their eligibility for payment as well as raising awareness of the guaranteed standards more generally. The increased proactive contact will provide us with further opportunity for maintaining our vulnerable customer data.

7.4 Fuel Poor and Off-Grid customers

Our fuel poverty strategy is built around providing information and advice to customers about the services and options available to them. We are aware that suppliers have a range of initiatives available, such those provided under the Energy Companies Obligation scheme. Although we have no similar scheme available to draw on, we recognise that we are in a position to develop a key role in interacting with customers through the information we have access to and have scope to form partnerships with others to address fuel poverty issues.

We are proposing the following steps:

- Analyse the data available for us to identify areas in which customers are likely to be classified as fuel poor
- Analyse any crossover between this data and our Priority Services Register
- Introduce the following information initiatives:
    - Offer information on our website to offer advice to customers on ways to reduce electricity consumption.
    - Train our contact centre people to provide support and information over the phone
    - Develop and offer information packs on how to be energy efficient
- Consider opportunities to introduce energy efficiency measures in areas where there is high density of fuel poor and where the Electricity North West network is congested to free up capacity and reduce reinforcement costs

In respect of the last of these initiatives, we commissioned National Energy Action (NEA) and Sustainability First to evaluate the potential for electrical load reduction measures to be implemented in an area of Stockport served by the Vernon Park primary substation, to help the fuel poor served by the substation and mitigate the need for network reinforcement.

NEA has produced a high-level assessment of the possible costs and likely effectiveness of a range of measures and interventions that could support reduced peak electricity of up to 2MW for the Vernon Park substation. NEA has also considered how these measures might contribute to the alleviation of fuel poverty. The next stage is to consider the business case for the identified options, on the basis of estimated capital costs, effectiveness in delivering social benefit, timescale and confidence level for the achievement of the anticipated load reduction.

The options under consideration include technological initiatives and also the less certain but more sustainably significant savings achieved by influencing people's behaviour to do such things as not using high load equipment such as washing machines at times of peak load. Amongst these we are developing initiatives to deliver practical lessons in energy use and consumption to the children of the North West.

We will engage with local authorities, agencies and suppliers to assist fuel poor customers by understanding their energy usage and increasing their awareness of energy efficiency options and possible alternative forms of energy. We will use partnerships to build a network of links to websites and reference information, and also provide the ability to refer customers to appropriate organisations that can help.

In particular, we will look at how we can work with Gas Distributors and others to consider solutions such as renewable heat technologies, alongside connections to the gas grid, as cost effective ways of helping fuel poor consumers who are currently off the gas network. We also see the developments in ‘connect and manage’ and the socialisation of domestic reinforcement costs to be helpful where low carbon technologies could be installed as the most cost effective solution

Our training packages for our contact centre people will specifically address the identification and handling of fuel poor customers.

8. Costs

Whilst most of the requirements of the Vulnerable Customer Strategy would not require specific funding, we have identified some areas which will incur costs. The IT and network investments have been included in our submission (see below); however we will not be seeking direct funding for the other initiatives. We believe that our developments across a broad range of customer service measures, including relevant stakeholder engagement, will drive sufficient incentive reward from the Broad Measure of Customer Service and the Interruptions Incentive Scheme to support these measures without a specific funding request.

Ofgem is increasing the stakeholder engagement element of the Broad Measure of Customer Service to around £1.8 million to incentivise DNOs in this area. The reward provided will be based on an assessment of the DNOs’ use of data and customer insight to identify solutions for vulnerable customers, as well as their ability to integrate this into core business activities. The success criteria are not yet clear, nor is the split between general stakeholder engagement and vulnerable customer strategy though Ofgem have said they will use a balanced scorecard approach to inform the allocation of the reward, which they hope to develop before the start of the RIIO-ED1 period.

Initiatives with costs included in the submission are shown below.

(£m)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**RIIO-ED1**
Resilience improvements of networks supplying Regional Hospitals	0.6								**0.6**
Resilience improvements of networks supplying a high density of vulnerable customers	0.4	0.4							**0.8**
IT systems for Customer Relationship Management	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	**2.0**

Appendix 1 - DNO Licence Requirements for PSR

PSR Definition

PSR Customers are Domestic Customers who:

(a) are of Pensionable Age, disabled, or chronically sick; and

(b) because they have special communication needs or are dependent on electricity for medical reasons, require certain information and advice about interruptions in the supply of electricity to their premises; and

(c) have either:

(i) personally asked the licensee to add their name to the Priority Services Register, or

(ii) had a person acting on their behalf ask for their name to be added to it, or

(iii) had a Relevant Supplier ask for their name to be added to it.

PSR Obligations

10.4 The licensee must:

(a) when a PSR Customer's name is first added to the Priority Services Register, give that customer appropriate information and advice about what precautions to take and what to do in the event of interruptions in the supply of electricity to the customer's premises;

(b) when it needs to make a planned interruption in the supply of electricity to a PSR Customer's premises, give that customer such prior advice and information as may be appropriate in relation to that event; and

(c) ensure, so far as is reasonably practicable, that during any unplanned interruption of supply to their premises, PSR Customers are promptly notified and kept informed:

(i) of the time at which the supply is likely to be restored, and

(ii) of any help that may be able to be provided.

10.7 If a Domestic Customer who is of Pensionable Age, disabled, or chronically sick asks it to do so, the licensee must agree a password, free of charge, with that customer that can be used by any Representative of the licensee to enable the customer to identify that person.

10.8 The licensee must provide facilities, free of charge, which enable any Domestic Customer who is:

(a) blind or partially sighted; or

(b) deaf or hearing-impaired and in possession of appropriate equipment, to ask or complain about any service provided by the licensee.

10.12 Nothing in this condition prevents the licensee from:

(a) including Domestic Customers additional to those specified at paragraph 10.3 in its Priority Services Register; or

(b) providing services to Domestic Customers that exceed those required under this condition.

Appendix 2 – Electricity North West website advice

Priority Services Customers

If you register as a priority services customer, we will inform you in advance of any planned interruptions and contact you proactively when we have an unplanned interruption.

Do you represent a residential care home or a similar organisation? If so please register as a priority service customer, we are here to help. We recognise that there are many customers who do not fall into the above category but still need our assistance during supply interruptions depending on their particular circumstances.

We have a strong partnership in place with the British Red Cross who can help with welfare service provision including hot drinks or just a friendly voice on the phone.

Our **PSR Application Form** includes the following options:

- I am registered disabled
- I have a disabled child
- I am visual or hearing impaired
- I am seriously ill
- I have mobility problems
- I am over 65
- Other (please specify)
- Do you or anyone in your household rely on medical equipment that is powered by electricity? (If yes, please specify the type of equipment)
- Are you the customer impacted? (If no, I am doing this on behalf of the above and have their permission to give out their details)

British Red Cross Partnership

Vulnerable residents in the North West can benefit from a targeted support campaign, thanks to Electricity North West's partnership with the British Red Cross.

We partner with the British Red Cross in order to provide customers with invaluable practical and personal support if they lose their power unexpectedly.

We operate at 99.99 percent reliability but unfortunately power cuts do happen due to external and environmental events such as metal theft, falling tree branches and bad weather. The partnership with the British Red Cross helps support those who need it, on the rare occasion when they are without power.

The campaign is tailored to the individual customer's needs – from a reassuring voice at the other end of the phone to house visits delivering a hot drink. We also provide a vital 'Customer Emergency Pack' which includes a wind-up torch, fleece gloves and a blanket to help people keep warm.

Customers eligible for the free service, which will be available continually throughout the year, are those who may find it particularly difficult to be without electricity, such as older or disabled people, or those with a medical dependency on electricity. People can sign up to Electricity North West's Priority Services Register via this link or by calling 0800 195 4141.

Letting Callers into your Home

There may be the odd occasion when a member of Electricity North West or one of our contractors will have to enter your premises. Before letting anyone into your home please be aware that:

- all Electricity North West staff and our appointed contractors have identity cards showing the employees name, identity number, colour photograph and a contact number for confirmation.
- the majority of Electricity North West staff and our contractors will have fully liveried vehicles.
- all of our staff and contract staff should have clothing showing they are from Electricity North West or the company they represent.
- Electricity North West and appointed contractors do not “cold call” so unless we have made an appointment, or you are without electricity, it is unlikely that anybody representing us will call at your home without making advance arrangements.
- If you are in any doubt do not let any suspicious callers in. Check the validity of any callers claiming to be from Electricity North West or one of our contracts by calling us on 0800 195 4141.

Password Scheme

If you live alone and have any concerns about letting someone into your home, you can join our password scheme or request a password when making an appointment.

ANNEX 10: EDUCATION, OUTREACH AND CORPORATE SOCIAL RESPONSIBLITY

Electricity North West Limited
Registered Office:
304 Bridgewater Place,
Birchwood Park,
Warrington,
Cheshire.
WA3 6XG.

Registered no: 2366949 (England)

Contents

1. Executive Summary

1.1 Overview

We define corporate social responsibility (CSR) as ensuring our business is successful in the inclusion of social and environmental considerations into our operations. This means looking at the needs of the business and communities and looking at ways to utilise our business strengths for community enhancement.

Our robust stakeholder engagement processes and programme, following the principles of AA1000, informs our CSR decision-making. Together these programmes offer a complementary and holistic approach to the long-term sustainability of our business, helping us both mitigate risk and positively contribute to the communities in which we work.

1.2 Following internationally-recognised best practice

Our commitment to being a responsible business is clear. Our Chief Executive, Steve Johnson, sits on the Business in the Community North West Advisory Board. We benchmarked ourselves against the Business in the Community CR Index for the first time in 2013 achieving a score of 54%.

We are committed to working with our stakeholders to improve this score from now and throughout the RIIO-ED1 period.

We will also continue to report against the Global Reporting Initiative (GRI) guidelines which we have done since 2011. GRI provides companies and organisations with a comprehensive sustainability reporting framework that is widely used around the world.

Together with our commitment to follow Accountability's AA1000 principles, we have a robust framework to base our CSR, stakeholder engagement and sustainability strategy on.

AccountAbility	CORPORATE RESPONSIBILITY INDEX	Global Reporting Initiative™
Stakeholder engagement principles of: • Inclusivity • Materiality • Responsiveness	Focus on: • Community • Workplace • Environment • Marketplace	Sustainability in: • Economic • Environmental • Social

2. Education

The predicted lack of engineers to come out of the education system is a key area of focus for our business, the community and the UK economy at large. It is predicted that by 2020, the UK will require approximately 830,000 engineers and yet, according to the Royal Academy of Engineering, we are only producing 23,000 annually. As a major engineering employer we need to play our part in encouraging students in the study of science, technology, engineering and maths (STEM) subjects. This will be of long term benefit to our business and the wider community.

We've worked hard with STEM providers in our area – Cumbria, Lancashire and Greater Manchester – to assess the curriculum and ascertain where it would be best for us to focus our involvement.

Due to the nature of the school system, and the requirement for students to choose subjects for GCSE levels, we have been targeting Key Stage 2 (8-11 year olds) with a scheme called 'BrightSparks' to ensure that an enjoyment and appreciation of the electricity syllabus occurs before students attend secondary school and make subject choices.

Up to 2023 we want to target more schools with our programme and also formally partner with other stakeholders such as the Museum of Science and Industry to promote STEM subjects. Through their annual science festival and other events, we aim to extend our engagement with young people outside of the classroom.

Developing a robust educational programme makes sense from a long-term strategic perspective. To implement our plans and ensure that the North West's energy requirements are met we need to ensure we have a workforce in place to deliver, now and in the future.

3. Safety

We are committed to promoting the awareness our customers have of the potential safety risks associated with contact with the electricity distribution system and how customers can avoid danger.

In the RIIO-ED1 period we will continue to identify potential risks and any incident trends that indicate increased risk due to changes in customer activities. Where necessary we will develop and implement appropriate communications to increase customer awareness of risk and precautions.

The types of communication methods we will use will include information available on our web-site, attendance and presentation at relevant events which provide the opportunity to promote awareness, personal response to specific customer queries regarding safety implications associated with their activities and running specific public safety events that can be attended free of charge.

4. Scheme overviews

Scheme: BrightSparks (Age 8-11)
***Provider*:** Cumbria & Greater Manchester STEM

Overview of scheme: One day session aligned to national curriculum that teaches young people about electricity and safety.

Over 6,000 children have taken part in this scheme since Electricity North West got involved.

Future developments:

- Metrics to demonstrate learning of day
- inclusion of fuel poverty messages to raise awareness
- Website resource
- Include a 'future technology' section to include smart meters and electric cars

Scheme: Tomorrow's Engineers (Age 12-15)
Provider: Engineering UK

Overview of scheme: The Tomorrow's Engineers programme delivers careers awareness through extra-curricular engineering activities that give young people in targeted schools, i.e. those who have not yet had the opportunity to take part in such a programme, the chance to get hands on with engineering and ask questions about what real-life engineering jobs entail. These are underpinned by curriculum-linked careers information and resources, and an ambassador engagement programme to reinforce careers learning and provide signposts on the next steps to a career in engineering.

This new scheme commenced in September 2013.

Future developments:

- Metrics to record effectiveness of session
- Link to BrightSparks programme

Scheme: Big Bang fair Cumbria (Age 11 – 17)
Provider: Cumbria STEM centre

Overview of scheme: The Big Bang Near Me hosts inspirational scientists and engineers with the sole goal of opening the minds of young people. There are careers workshops to visit and local companies' on-hand to give insight into future careers nearby and beyond. They are there to answer questions and enthuse the engineers and scientists of the future.

We started sponsoring this annual event in 2012 and plan to continue sponsorship in the future.

Future developments:

- Link to graduate and apprentice scheme
- Support CREST awards which are linked to the Big Bang fair

Scheme: STEM ambassadors (Employees)

Providers: Regional STEM centres

Overview of scheme: Ambassadors are an invaluable and free resource for teachers and schools. They offer their time voluntarily to enthuse and inspire students within schools about STEM subjects. They can do this through a variety of activities such as clubs, careers talks, helping with school events, lessons and competitions, and much more.

Future developments:

- Increase the number of employees trained as STEM ambassadors
- Increase the number of school sessions we take part in

Scheme: Museum of Science & Industry (MOSI)

Provider: MOSI

Overview of scheme: Sponsorship of the annual Manchester Science Festival which attracts over 80,000 visitors, in order to inspire the next generation of science students and raise awareness of the company and the opportunities available.

Future developments:

- Installation of car charging point at MOSI – offer issued
- Collaboration on the re-furbishment of the power hall

Current initiatives:

- Continue to sponsor employees individual community involved through the charitable donation process. 15 employees were supported in 2012-13 with a further 25 expected in 2013-14.
- Continue to support the employee chosen corporate charity (currently The Christie)
- Offer and develop the employee volunteering scheme (currently at two days per employee per year)

ANNEX 11: ASSET MANAGEMENT POLICY

Electricity North West Limited
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Registered no: 2366949 (England)

Electricity Policy Document 215

Issue 2 July 2007

Asset Management Policy

Contents

Approved for issue by the Technical Policy Panel

Amendment Summary

Amendment No. Date	Brief Description and Amending Action
0 14/03/96	Originally drafted as Code of Practice 201: Issue 1 Prepared by: PJW
1 24/03/98	Appendix 2 removed; superseded by EPD204 Prepared by: MK
0 13/01/05	Reconfigured as EPD215: Issue 1 Updated to take account of the Distribution Price Control Review (X_{d4}) and organisational changes. Prepared by: Peter Leather Approved by the Standards Steering Group and signed on its behalf by Paul Whittaker:
0 27/07/07	Issue 2 Updated to take account of PAS-55 requirements Prepared by: Jonathan Booth Approved by the Technical Policy Panel and signed on its behalf by Simon Rushton:

ASSET MANAGEMENT POLICY

1. INTRODUCTION

This Electricity Policy Document (EPD) applies to the assets of Electricity North West Limited, hereinafter referred to as Electricity North West. It sets down the policy for managing the assets comprising the electricity distribution network. It describes how other Electricity North West' policies, Codes of Practice (CP) and procedures are to be considered and integrated, in order to optimise the whole life management of the constituent parts of the network, to produce a holistic approach to meeting business needs.

It is also intended that the policy shall be, out of necessity, dynamic. It is to be used to construct the dynamic strategic plans required by the company in order to meet changing business needs, on a year-on-year basis.

Throughout, all the following fundamental principles should be borne in mind. The network exists to transport electrical energy from the National Grid and from generators to consumers. It shall be designed and constructed using the minimum amount of equipment necessary to ensure that electricity distribution is achieved with the appropriate level of safety, quality, security and availability. These levels are expected to change over time in accordance with our customers' increasing expectations for improved levels of service. All the associated policies shall be applied and integrated as appropriate to achieve this.

2. SCOPE

This EPD applies to the whole life approach to the management of Electricity North West' network assets. This whole life period is divided into the following stages:

(a) Network design

(b) Installation

(c) In service operation

(d) Maintenance

(e) Refurbishment

(f) Removal

(g) Replacement

3. PRINCIPLES OF ASSET MANAGEMENT

The principles set out below are to be applied within the framework of the legal, regulatory and statutory obligations with which Electricity North West is required to comply.

Bearing in mind that the network exists to transport electricity, the principles of its management are:

- The network shall be operated to ensure that the risk to the network operators and to the general public is properly managed and, so far as is reasonably practicable, limited.

- The service to customers shall be modified or improved, in order to meet customers' needs and in accordance with the regulatory regime.

- Within the constraint of the above two requirements, the network shall be designed, constructed, operated, maintained and dismantled in a manner consistent with minimising its whole life cost.

- Decisions will be informed by the best available asset data held within the corporate databases, and risk assessments undertaken in line with the company's risk assessment procedures.

- Resulting intervention plans will be incorporated in the Company Business Plan (CBP) which is reviewed on an annual basis.

The application of these principles shall be undertaken at all stages of the network life cycle, but may carry different weightings to suit the point on the life cycle of individual or groups of assets, the customer needs and the business needs. Electricity North West is committed to applying a process of continual improvement to these asset management principles.

4. QUANTIFICATION OF THE PRINCIPLES

4.1 Risk to Operators and the General Public

Risk shall be assessed by using Electricity North West' standard risk assessment procedures. They shall cover all areas which generate potential risk, because activities are undertaken and products employed. The assessments shall consider those undertaking the activities and third parties, and have due regard for the environmental impact of the products and processes employed. Risk assessments describing acceptable levels of risk against which in-service changes can be benchmarked shall be produced as follows:

- Assessments covering changes to the network design policy and asset replacement policy shall be undertaken by the Network Planning Policy Manager.

- Assessments covering extensions to the network using approved network designs shall be undertaken by network designers. The Connections Compliance Manager shall be responsible for assessing the risks associated with the adoption of networks, designed and constructed by Electricity North West Networks and other Independent Connection Providers (ICP).

- Assessments covering construction work shall be undertaken by the construction project managers undertaking work on the Electricity North West' network.

- Assessments covering network operations policy shall be produced by the Operations and Safety Section.

- Assessments covering the introduction of new equipment and processes shall be undertaken, as appropriate, by the Plant Policy Manager, the Overhead Policy Manager, the Underground Policy Manager and the Protection and Control Policy Manager.

- Assessments covering the policy on the inspection and maintenance of the existing network equipment and the re-use of refurbished equipment shall be undertaken by the appropriate maintenance policy manager.

- Assessments of required medium-term asset serviceability, including asset fault rates and network capacity shall be undertaken by the Asset Performance Managers.

- Risk assessments carried out on in service assets shall be the responsibility of the Electricity North West Limited (Electricity North West).

4.2 Customer Service

4.2.1 Customer service shall be defined using the following parameters:

- The minimum standard of security to be achieved shall be the standard set by the Director General of Electricity Supply, as stipulated in Electricity North West Distribution Licence (not less than P2/6).

- The internal Company targets for CI, CML and multiple interruptions, which may be the same as the Ofgem targets or different targets set by the Company to fulfil business needs.

4.2.2 Measurement of achievement shall be by comparison of actual achievement against Company targets.

4.3 Cost

The aim is to minimise the whole life cost of the network, including where appropriate the income that assets may generate over their lifetime (eg through their contribution to incentive out-performance). The requirement of this policy is to look at the remaining life period of all of the existing assets and the whole life period of all new assets, with the aim of optimising regulatory profit over that life period.

Remaining life cost studies shall use the best estimate of actual remaining life of individual assets. The analysis shall include the cost for individual types of assets as well as for families/groups and for circuits and networks. Whole life cost studies shall use the design lives of assets which are defined in EPD204. However, the actual life of any individual item of equipment shall be determined from a condition-based assessment.

5. INVESTMENT PATTERNS

Future plans and programmes of work will be developed through the application of the asset management policy and its associated targets to the current asset base to ensure consistency between asset management objectives and the plans put in place to achieve those objectives.

Replacement activity shall be determined through the application of Condition-Based Risk Management (CBRM) techniques to assess the current and expected future risk of the assets and to design appropriate interventions consistent with achieving the overall asset management objectives.

Such plans will be formally issued in the form of the CBP and set in the context of 25-year projections.

It is the established practice, with the capital investment programme, to build and replace networks on the basis of the most economical designs and the lowest cost equipment available. The revenue investment has been made on a more regularised basis in line with, say, the ongoing maintenance of the network. However, the balance between these two budgetary areas may be altered year-on-year to meet the needs of the business. This shall be achieved by making best use of the appropriate resources available over any given time period, for example, by deferring revenue expenditure, in order to concentrate on capital investment, which may be required to remove a large number of high risk, low reliability assets from the network.

Such variations may affect the application of a whole life management policy. Therefore, the effects of such changes should be evaluated by those involved in reviewing budgetary re-alignment when developing the asset management plan.

6. FORMULATION OF POLICIES COVERING EACH OF THE PERIODS OF LIFETIME

In order that policies may be fully developed such that they provide clear direction on how to meet the business needs, make best use of the available technology and are practical and usable by the practitioners of the policy, their formulation shall be undertaken under the control and direction of the Technical Policy Panel (TPP). The process for the approval, including the review by all interested sections of the business, of all documents setting out the policies, practices and specifications to be used by Electricity North West shall be as described in EPD001.

7. ASSET MANAGEMENT SYSTEMS

Effective asset management requires the use of databases against which the assets can be registered and within which the condition information gathered during commissioning, inspections, and diagnostic tests can be lodged. The IT system shall be able to function as a tool which will assist in the processing of the condition information held and wherever possible, in the determination of the inspection and overhaul regimes. The system shall be able to produce condition reports based upon the information held and contain condition triggers, which shall prompt the review of the equipment group for consideration of refurbishment, replacement or removal. The system shall be capable of producing inspection, maintenance and refurbishment schedules.

The system shall be further developed to allow assessment of performance of the network, preferably on a per circuit basis, thus allowing reviews of the effectiveness of investment decisions.

8. DOCUMENTS REFERENCED

ENA ER P2/6 - Security of Supply

Electricity North West Distribution Licence

EPD001 - Documentation Standards and Technical Library Service

EPD204 - Distribution Network Equipment Asset Lives

9. KEYWORDS

Asset; Construction; Maintenance; Operation; Planning; Refurbishment.

ANNEX 12: CONNECTIONS PROCESS IMPROVEMENT PLAN

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Contents

1. INTRODUCTION

The purpose of this Annex is to detail the improvements we have made and will continue to make to our connections processes in order to improve customer satisfaction and to ensure customers have a choice in who they wish to provide their connection. We have developed detailed processes over the years initially to ensure compliance with Guaranteed Standard of Performance requirements and to ensure that we provide a level playing field to Independent Connections Providers and Independent Distribution Network Operators (Third Party Providers) by ensuring consistency in our approaches.

We were the first distribution network operator (in 2011) to have price regulation lifted in three areas of connections where we have been able to demonstrate to Ofgem's satisfaction that there is evidence of competition and buyer power:

- metered demand connections extra high voltage (EHV) work and above;
- metered distributed generation (DG) High Voltage (HV) and EHV work; and
- unmetered connections private finance initiatives (PFI).

During May 2013, price regulation was lifted in another three areas:

- metered demand connections high voltage (HV) work;
- metered demand High Voltage (HV) and EHV work; and
- unmetered connections Local Authority work.

Overall this equates to around 80% of the connections market in the North West where we have demonstrated that there is effective competition. We have submitted applications for the remaining three segments and we believe we have provided sufficient evidence for these to be passed also.

We have welcomed competition to drive up standards and help customers get the best deal, and we will continue to lead the industry in promoting competition in connections.

This Annex provides further detail on how we will deliver the outputs we have committed to in section 4 of our business plan for the RIIO-ED1 period.

2. CONNECTIONS PROCESSES

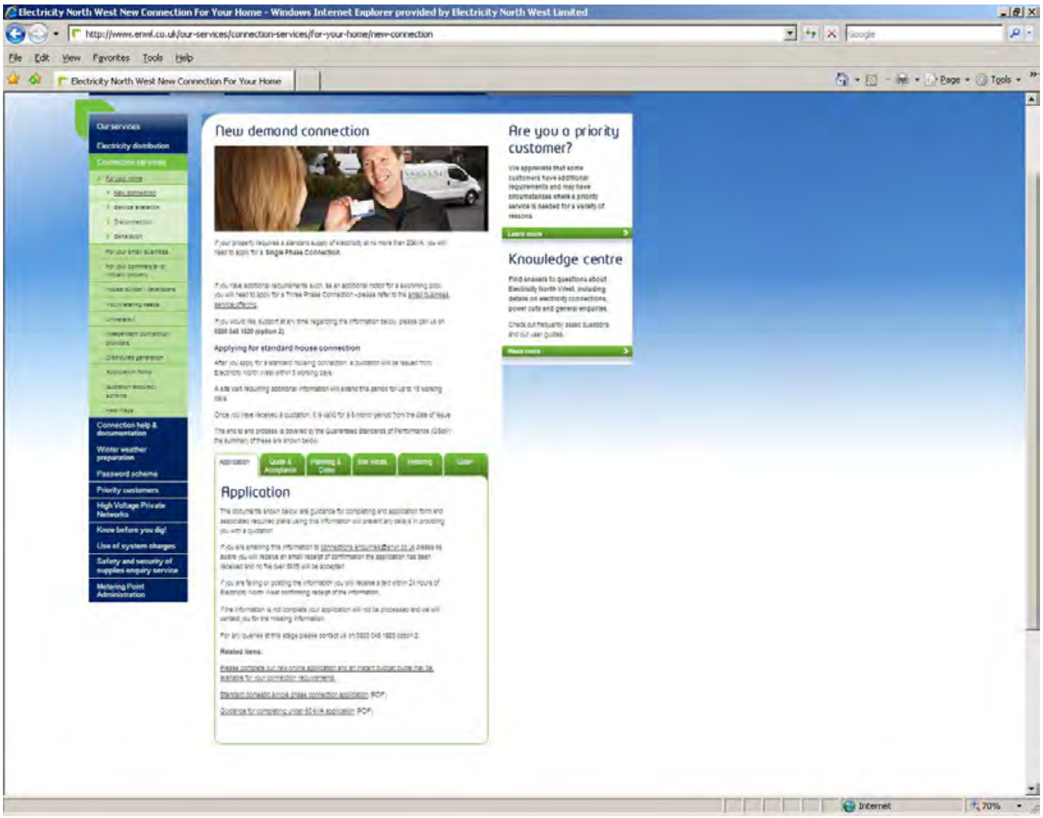
Our connections processes need to meet a number of objectives:

- To give our customers an efficient connections service
- To ensure compliance with the Connections Guaranteed Standards of Performance and obligations on provision of non contestable services, i.e. Standard Licence Condition 15
- To ensure compliance with the standards of performance for the connection of distributed generation
- To ensure Independent Connection Providers are able to compete effectively and are able to provide an alternative service to our customers

Our connections processes are published on our website with specific pages for different types of customers, A link to our connections is given below:-

http://www.enwl.co.uk/our-services/connection-services

An example from the website is given below:-



3. CHANGES TO OUR PROCESSES

We have recognised that our focus on compliance and ensuring that the connections market is fully open to competition may have resulted in services not being provided to all customers as quickly as they could have been.

The introduction of the Guaranteed Standards of Performance (GSoP) in 2010 meant we were exposed to a new risk in having to make payments to customers where we did not meet specified levels of service. Comprehensive regulatory guidance was issued to seek consistency across the sector. In response to this we, like many other companies, were focused on compliance, both complying with the rules and seeking to reduce the levels of payments we made. We have sought to take a reasonable approach to the standards and have not used the “small print” to avoid making payments. Where we have not met the standards we have made payments to customers.

In particular, ensuring we have all information available from customers can have an impact on our average time to connect and our average time to issue a quotation. The time taken can be measured from two different points in time, either from when we first receive an application from a customer or when we have all the “minimum information”. “Minimum information” is the information specified in the regulatory guidance that we need to be able to progress an application.

Our performance on both minor and major connection segments since 2011 has been:

Average Time to Quote (days)	2011/12	2012/13
Single connections	7	10
Up to four connections	11	12
Major Connections	32	24

Average Time to Connect (days)	2011/12	2012/13
Single connections	76	78
Up to four connections	81	87
Major Connections (excluding EHV)	188	201

Note that the average time to connect measures the period from acceptance to the connection being made. Even if the customer does not wish to have the connection made at the time they accept, this time is included in the measurement.

As we state in our business plan, we will deliver a level of service which is among the best in our industry. This will be underpinned by our wider strategy for improving customer service and tailored as required to meet the specific needs of these customers.

We will provide a quotation after receipt of the customer's initial application on average within:

- Single domestic connections – six working days
- Up to four domestic connections – ten working days
- All other connections – 25 working days

We will complete the connection after agreeing terms with the customer on average:

- Single domestic connections – 35 working days
- Up to four domestic connections – 45 working days
- All other connections (excluding EHV)– 50 working days (from when the customer is ready)

Our target is to reduce the average time to issue quotations, in particular for those not classed as major connections. For the average time to connect, we plan to reduce this by more than half in all areas. In order to make these improvements, the overall processes have been reviewed end to end and the following improvement initiatives have been identified.

3.1. Registration Process

We have altered the way we treat customer applications to improve the service to customers. When we receive an application but have not received the "minimum information", we will seek to progress the application as if it has got all the information and start the process immediately. If information is missing, we will proactively contact the customer and seek to get the quote out as quickly as possible. This will remove some of the delays caused by us asking for and then waiting for this information. We will email the customer on the day of receipt of an application to confirm receipt and provide a reference number. The planner will also call the customer on the day of receipt to discuss the job. The planner will discuss the customer's requirements, explain the process and the timescales for quoting and when the customer requires the connection and will provide direct contact details.

3.2. Quotation

We already have an online capability that allows a customer to get an estimate for their particular connection. We will plan to enhance this to develop a full on-line quoting tool. Our aspiration is to allow same day quoting for single services work. This can be either by the customer "self serving" via our website or by them applying to us and then us giving them a call to discuss and quote.

For larger, more complex projects we recognise that different approaches are required. We have introduced a series of 'drop-in' sessions to allow customers to talk to one of our planners before they have even submitted an application. This gives a customer access to our technical staff even if they have never worked in our area rather than relying on personal contacts to allow a discussion. These drop-in sessions are intended to allow customers to come in with a number of options and have an initial discussion, discuss particular issues they have or whatever their concern is.

When the customer actually submits an application we will meet with them to ensure we understand their requirements and to develop a connection offer that meets their needs. When we have issued the quotation we will also make a courtesy call to confirm that they have received it and clarify any points in the offer that are unclear to them.

For smaller projects (less than £5,000) we are about to introduce on-line and credit card payments. For connection charges in excess of £20,000 we already allow the customer to make an initial payment on acceptance and then agree a payment profile with them. Customer feedback has been positive on this, particularly with Distributed Generation connections which often have a protracted lead time due to the need to get planning permission.

3.3. Website

We see our website as a key communication channel for us and we continually look at how we can improve it. We are currently redesigning the connections web pages based on recent market research which was undertaken to provide feedback from different customer bases around the look and feel of the existing website. This will now result in an improved customer experience, and make our information more accessible.

As part of the website redesign, we are also improving some of our supporting literature including a combined application and quotation pack, which will set the expectations of the customer at the very beginning of the project.

Our mobile app for smart phones and tablets went live at the beginning of 2013. We are also developing versions of our website that are more compatible with handheld devices as many customers now access our website from these devices.

We appreciate that our customers are familiar with all sorts of service companies that allow customers to track the progress of, for example a parcel from order to delivery. We are implementing an online application so that customers can track the progress of their project through the whole life cycle of their connection.

3.4. Third Party Providers

Our processes for Third Party Providers are acknowledged to be some of the best in the country and we received many letters of endorsement from Third Party Providers in support of our Competition Test Notices. Our approach has been to minimise the impact we can have on the processes of any Third Party Provider making a connection in our area.

We continue to engage with Third Party Providers and have run workshop/seminars on a six monthly basis. We have used these to provide feedback on what we have done, what we are working on and to get feedback on proposals. These also give these stakeholders the opportunity to raise issues with us directly. Third Party Providers can also make use of the drop in sessions mentioned above.

3.5. Estates and Wayleaves

Getting the required permissions to install our lines and cables can add delay to a connection project, particular if we need to go onto or across land not owned by the customer. We have developed a booklet that explains why we need to get these consents, how the process works and what can be done to make it flow smoothly. This is available on our website and is issued with all quotations requiring legal consents.

As part of the initial payment on acceptance, a customer can elect to pay any legal charges associated with the connection. This allows us to progress this aspect of the work in advance of any physical works starting.

3.6. Delivery

For the smaller connections, in order to meet the challenging timescales we have set ourselves we have worked with our subcontractors to improve the overall process. We are achieving this by examining in detail the handovers at each stage and passing information more quickly so that it can be put into the contractors' work programme at an earlier stage. We are currently trialling this new process with positive results.

With our contractors, we have developed a 'three day cycle'. This means we excavate the work on the first day, complete the jointing to the network the next and complete the backfilling of the holes and reinstate the surface on the third day. This allows us to reduce the amount of notice we give local authorities for undertaking the work.

We recognise that there can be a considerable delay between a customer accepting a quotation and making payment and works commencing. This can be for a number or reasons such as the customer not being ready for the connection to be made or for the time taken to allow notices to be given to local authorities for road works to enable the work to be undertaken. We plan to have greater contact with customers to help them get their site ready, including providing the necessary materials to them if required. We will also look to change the time when customers need to pay for the works to nearer the time it is expected that we will carry it out.

For larger connections, the feedback from customers is that meeting their programme days is the most critical requirement. Nevertheless, we intend to shorten the period from acceptance to connection significantly. We are developing a process with our procurement team to improve delivery by compressing timescales on plant delivery which will include an emergency option if customers require their connections urgently.

3.7. Stakeholder Engagement

The new regulatory incentive being introduced for RIIO-ED1 will only have penalties applied to market segments where the DNO has not passed the Competition Tests. We have already passed six of the nine segments and aim to have passed the remaining three segments by 2014.

As we believe that engagement with our customers is fundamental to us providing good customer service, we intend to develop and implement a comprehensive engagement strategy modelled on our approach to stakeholder engagement. This will ensure we understand the needs of our major connections customers across the different market segments and develop policies, processes and products which satisfy them. We will do this for market segments even where we have passed the Competition Tests and there is no regulatory requirement to do so.

We will continue our engagement with Third Party Providers to ensure that we provide non contestable services that meet their needs across all the market segments.

4. NEW SYSTEMS AND PROCESSES

We have recognised that our supporting IT infrastructure for connections will need enhancing for our services to keep pace with ever changing customer expectations. To address this, we have commenced our Nexus Programme which is a significant business change initiative and a critical element of our plans for the RIIO-ED1 period. The core of the programme is a SAP re-implementation element which is the catalyst for the back office and Connections process change improvements to meet the strategic goal of improving customer service, improving efficiency and reducing the cost of our business support and administrative processes.

This programme will optimise our business administration and Connections functions by identifying lean process improvements based on standard SAP functionality. It will provide an enterprise environment which is based on cleansed maintainable data from which future operational initiatives will be easier to integrate, providing “joined up” and “end to end” solutions. In implementing this approach we will be looking at best practice implementation in other utilities and businesses.

ANNEX 13: SMART GRID STRATEGY

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Contents

1. Executive summary

Welcome to our smart grid strategy. This is an exciting time for our business; we face unprecedented change in the face of emerging challenges and opportunities brought about by climate change, the economic needs of our customers and the ever increasing importance of the reliability of energy networks. Our customers and stakeholders should be assured that our business plan is designed to meet these challenges and deliver the benefits, efficiencies and services they need.

Core to our business plan are three critical developments; our innovation strategy, our smart meter strategy and this our smart grid strategy. Our innovation strategy, Annex 23 describes our overall approach to embracing and developing new techniques and technologies for the benefit of our stakeholders. Innovation pervades all areas of our business plan from customer service, asset management planning and field delivery. Key to our businesses success will be the realisation of the significant potential of smart meters and smart grid. Our strategy for realisation of the benefits of smart meters is outlined in our smart metering strategy, Annex 28.

The development of smart grids is being championed as a key facilitator in the transition to a low carbon, low cost, greener future for GB. In this document we outline our vision of a smart grid in Electricity North West and point to a number of key activities and work areas which are contributing to the development of your future distribution network. Table 1 below outlines our summary forecast of the benefits of smart grids for our stakeholders over the RIIO-ED1 and RIIO-ED2 periods.

Table 1: Innovation funding and customers' benefits

<table>
<tr><th rowspan="2"></th><th rowspan="2">DPCR5 investment £m</th><th colspan="2">Savings £m</th><th rowspan="2">RIIO-ED1 investment £m</th><th colspan="2">Savings £m</th></tr>
<tr><th>DPCR5</th><th>ED1</th><th>ED1</th><th>ED2</th></tr>
<tr><td>IFI</td><td>8.5</td><td rowspan="2">64.1</td><td rowspan="2">55</td><td></td><td></td><td></td></tr>
<tr><td>LCN Fund</td><td>25.3</td><td></td><td></td><td></td></tr>
<tr><td>NIA</td><td></td><td></td><td></td><td rowspan="2">24</td><td rowspan="2">28</td><td rowspan="2">120</td></tr>
<tr><td>NIC</td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>33.8</td><td>64.1</td><td>55</td><td>24</td><td>28</td><td>120</td></tr>
</table>

2. Our vision

The demands on electricity distribution networks are evolving owing in part to government strategy on climate change, increases in fuel prices and the move to de-carbonize heating and transportation. To fulfil our role in helping address these challenges we are proposing a number of key changes to the way in which we operate and maintain the distribution network. These changes are commonly referred to as a smart grid. This document outlines our vision of a smart grid and contains details of the strategic direction we will take as we transition to this future.

2.1 Smart grids by 2035/ 2050

At the heart of any smart grid are smart, informed and empowered customers who are enabled through a variety of systems to consume or produce power efficiently at times to suit their needs. This vision requires customers to have access to easily understood information representing cost drivers such as connections, system constraints and raw generation pricing from all components of the supply chain. The design of smart metering and other interactive smart grid systems such as home based energy management will evolve rapidly to allow these complex cost drivers to be presented in simple ways to customers allowing them to make informed choices.

Commercial offerings such as managed connections will continue to evolve delivering new products and services to customers. Initially smart grid developments have focused on generation, and industrial and commercial (I&C) customers enabling them to connect more demand and more generation at lower cost. These changes have brought competitive advantages to their businesses generating real value. It is our customers' need for affordable, reliable and secure power supplies that have allowed us to define and set out our smart grid strategy.

This work has already expanded to agencies such as social landlords who are embracing the opportunities offered and with the advent of smart metering will rapidly expand to encompass all customers.

To enable real choice and value for customers our network will need to change from its historic static design principle and become ever more interactive to customers' needs. We have already seen the huge benefits for customers from grid automation for supply restoration. These technologies are now being adapted for energy balancing and we will soon see truly adaptive networks sensing customers' usage, anticipating their needs and adapting the grid to deliver their needs.

In turning our vision into a deliverable business plan we have adopted a number of key guiding principles:

- Customers have already paid for the power grid of today and much of this will still exist in 2050, therefore we must, wherever economic, exploit this huge asset to the maximum extent. Much of our work to date has therefore centred on maximising grid utilisation and the delivery of new services such as those identified in our CLASS[1] project from existing assets;
- Engagement of customers in the delivery of benefits requires a detailed understanding of their current and future needs. This principle is informed by direct engagement with our stakeholders and led to the development of our C_2C[2] project and the inclusion of the associated benefits within our business plan;
- Smart technologies can only ever offer real benefits if they solve real customer problems at a competitive price. This principle is important and assists us in focusing the main part of our development work on technologies that can deliver benefits today and in evaluating technologies such as storage that may be viable in the future;
- Truly smart solutions often require radically new approaches to old problems and hence our work challenges many existing engineering norms. Examples of this include our Smart Street[3] project that transforms how low voltage networks are operated by changing network configuration and voltage control principles to deliver up to 40% additional capacity for use by customers.

Core to many smart grid solutions is the use of operational information technology systems such as advanced distribution network management systems utilising data from a variety of network sensors and critically smart meters. The information technology system investments contained within our business plan are enablers to delivering this vision for our customers.

We recognise that Suppliers, generators, aggregators and transmission operators all have a role to play in delivering this vision for customers. Work on enabling market structures is therefore integral to the delivery of smart grid benefits and we will continue to play a leading role in the various industry fora that will inform the evolution of the GB energy sector. Our guiding principles in this work will be securing the benefits smart grids offer for our

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[1] Further information on our LCN funded Customer Load Active System Services (CLASS) project is available at: www.enwl.co.uk/CLASS.

[2] Further information on our LCN funded Capacity to Customers (C_2C) project is available at: www.enwl.co.uk/C2C.

[3] Smart Street is the delivery name for our LCN funded *eta* project. Further information is available at: www.enwl.co.uk/smartstreet.

customers. Where efficient we have actively supported the opening up of market segments to new entrants such as IDNOs, this approach may be efficient in future for storage ownership models and for allowing DNOs to offer DSR services into the various ancillary services markets.

2.2 Our innovation strategy

Core to our business plan are three critical developments, our innovation strategy, our smart meter strategy and this our smart grid strategy. Our innovation strategy describes our overall approach to embracing and developing new techniques and technologies for the benefit of our stakeholders. Innovation pervades all areas of our business plan from customer service, asset management planning and field delivery as it is a core company value. Key to our businesses success will be the realisation of the significant potential of smart meters and smart grids. Our innovation strategy contains many smart grid development examples and this document contains additional details on our future work.

2.3 A shift in emphasis

The move to a smart grid is resulting in a change in emphasis from the traditional approach of ‘fit and forget’ asset installation and operation to one of actively managed energy distribution services. Here, network operators manage their networks actively on behalf of customers to minimize network constraints and optimise asset utilization. This requires use of novel technical and commercial techniques supported by the use of advanced communications and control infrastructure. These techniques will manifest themselves in a range of new activities and services and will require a different approach to be adopted. In particular real-time knowledge of the networks capability, status and users’ requirements becomes crucial as does the introduction of increased volumes of remotely controllable plant.

Our entire asset management approach will move to a real time balancing and optimisation focus as the power network monitors customers’ changing needs through smart metering and responds to meet them minute by minute.

This change will result in a switch in investment focus from heavy power assets such as new circuits and transformers to advanced knowledge based network management systems, smart meter data, sensing technologies and commercial techniques such as Demand Side Response contracts.

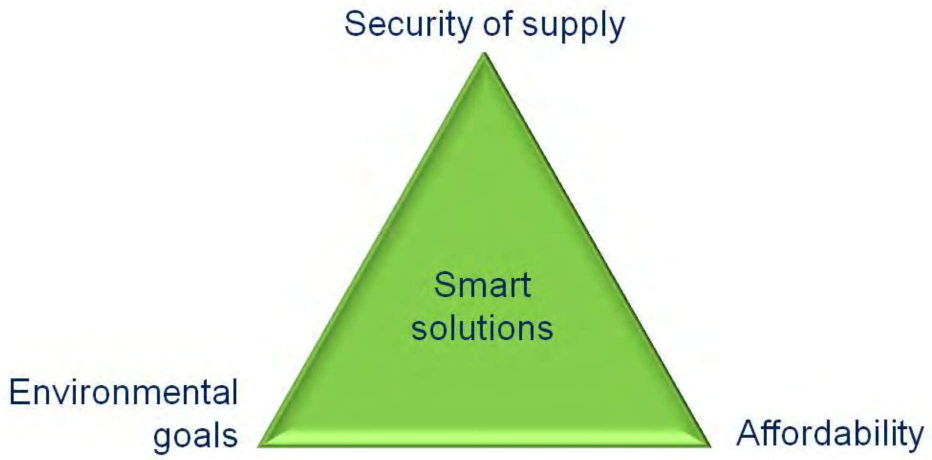
3. Our challenge

During the next ten years our customers and stakeholders will respond rapidly to technological, economic and environmental drivers on them. These will significantly affect our business and we expect to face fundamentally different challenges to the ones we have traditionally managed. We have heard of the expected increase in electricity demand driven by decarbonisation of heat and transport needed to meet environment targets. Some forecasts show this as potentially doubling customers’ demand for electricity but what is often not fully appreciated is that associated with this increase is an increase in customers’ dependency on electricity; as it becomes their sole source of energy. Our stakeholders tell us that reliability of supply and affordability are their paramount concerns and increased dependency will become a key satisfaction driver. Combine these priorities with significant increases in demand and the connection of large volumes of wind generation, solar PV arrays, micro-CHP generation and the scale of the challenges to our business become apparent.

3.1 Emerging need

Our network has already had to change to accommodate stakeholders’ needs; for example we now have distributed generation connected equal to 50% of our maximum demand - a scenario beyond any of our projections just 10 years ago. Our smart grid strategy outlines how we will implement our innovation work to offer new commercial and technical services to customers. The changes required will move all distribution network businesses increasingly towards distribution system operators.

Figure 1: The networks' trilemma



Recent work in both GB and elsewhere across the world seeks to harness new technologies, new commercial approaches and customer engagement to strike the right balance between of all the factors shown in the above diagram. Our smart grid programme is working to develop the smart solutions that will enable the most cost effective solutions and tradeoffs.

3.2 Changes in customer behaviour

Our customers are starting to amend their behaviour and will continue to do so as GB responds to the challenges brought about by climate change and the global economy. As part of its ongoing commitment to European targets on carbon emissions reduction, the UK government has launched a number of initiatives on energy efficiency, carbon costs, renewable energy generation sources and electric vehicle and heating incentives. Coupled with a general increase in public awareness of low carbon issues these initiatives are expected to significantly affect electricity consumption in terms of usage patterns and overall demand and generation levels. As an example, solar PV feed-in tariffs, introduced in the UK in 2011, have resulted in a number of large clusters of installations across the network thus introducing intermittent electricity generation to low voltage networks where it was never originally envisaged, changing the low voltage network from a largely passive to an increasingly active state.

Furthermore, the Renewable Heat Incentive, introduced in 2012, is expected to result in similar levels of customer activity over the years of RIIO-ED1 giving a substantial additional demand from heat pumps. Social landlords have been early adopters of PV and our work shows that this pattern is being repeated with renewable heat technologies resulting in geographic clustering of installations. We are working with these key stakeholders to understand their needs and the effect of these low carbon technologies (LCT) on our network through a variety of IFI and First Tier LCN Fund projects. These projects encompass advanced sensing technologies, customer demand patterns and network analysis.

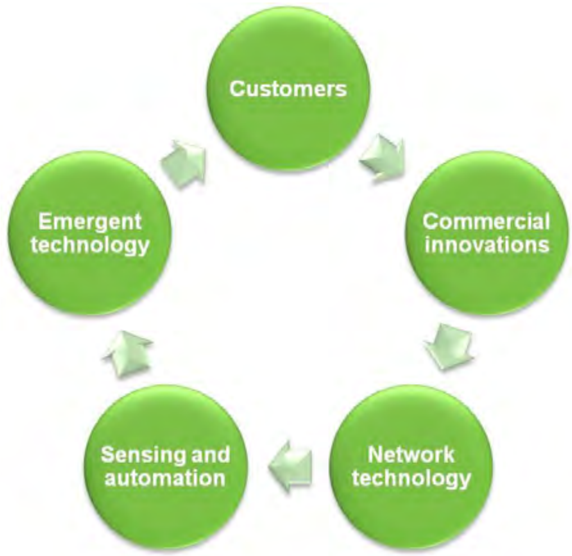
There is still significant uncertainty in the development and adoption of low carbon technologies and consequently on the development of smart grids. This is very important when considering the very long term nature of investments in electricity infrastructure. Electricity North West has therefore adopted two planning horizons; the short to medium term representing 2013 to 2023 and 2024 to 2035 for the long term. The development of technologies over the next 10 to 15 years will have a significant impact on the configuration and operation of the network out to 2050. As such only these initial key periods are considered in detail within this strategy document.

4. What are we doing to make the smart grid a reality?

The evolution of smart grids has been underway for the past several years however our work has now advanced to a stage where pilot projects are turning into business as usual bringing a range of benefits to customers.

In this section we outline the main areas of our work, our progress so far and our anticipated future direction. For us our customers' changing needs is the starting point for all our thinking about the development of our business. From this flows our thinking on new commercial innovations and new technologies, and these interact in a continual cycle as illustrated in Figure 2 below. This means that whilst we can anticipate and plan for the changes required we must continually review all elements of the cycle to ensure customers receive all the benefit smart grids offer. This is ensured by our ongoing engagement as laid out in our innovation strategy, annex 23 and you will see the results of this in our annual innovation strategy report.

Figure 2: Continuous development



4.1 Industry leadership and collaborative working

It is clear that the scale of the smart grid challenge cannot be economically solved by one business alone; hence we have for some time been actively leading industry collaboration through a variety of fora.

Our chief executive is a member of the Smart Grid Forum and has lead the development of the Transform[4] model in Work Stream 3. He also chairs Work Stream 7 which is now undertaking detailed modelling to support the development of smart distribution grids with a 2030 horizon.

We chair the strategic technology programme delivered by EA Technology Limited at which all distribution network operators collaborate in the research, development and deployment of new smart grid technologies. We are one of the founding members of the Energy Innovation Centre which seeks to attract and evaluate new technology proposals from new sector entrants. Additionally Electricity North West chairs the Energy Networks Association's LCT working group and which has previously led the industry response to technologies such as domestic heat pumps. We also actively participate in the Smart Grid Forum chairing a number of the smart grid related Work Streams.

We chair the Distribution Code review panel and have used this opportunity to push the development of both GB and European standards work. Our innovation work has been directed to drive real change into network thinking challenging many of the established norms.

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[4] A modelling tool collaboratively developed by the DNOs and EA Technology.

4.2 Working with customers

Our innovation work with customers includes domestic, I&C and generation customers. Numerous projects are trialling demand side response in all its forms whether that is load shaping, peak demand shifting, or post fault response. We are also trialling a variety of means of delivering price signals and incentives to customers through new connection contracts and changes to existing customer contracts.

Our LCN Fund projects C_2C and CLASS are focused in this vital area to get customers involved in the operation of our network by offering them additional value and services they need.

Commercial innovation is core to all our work with customers and we seek to ensure smart grid solutions are commercially attractive and appropriately marketed to customers. Our work on C_2C contained a significant element to evaluate the different drivers within different segments of the I&C market and to understand which contract forms would be viable. This study enabled us to price post fault DSR and we have already started offering these new contract forms to customers through managed connection agreements as a direct result of our innovation work. Our work proves that commercial innovation runs in parallel with technological innovation and these two work areas are the real enablers of smart grids.

Our work on the marketing of DSR contracts through both C_2C and its predecessor projects has shown that network operators will need to change to re-establish a direct relationship with customers. Whilst agents and aggregators have an important relationship to play, our work shows that maximum value can best be ensured for customers when we work directly with them to understand their needs.

Our business plan contains provision for the establishment of a dedicated DSR sales team who will work with customers to purchase commercial solutions to deliver the benefits identified in our plan. We have already established strategic customer relationships with customers who own and operate geographically diverse sites; as we see these as key partners in establishing DSR as a business as usual smart grid solution.

Our work with customers extends wider and encompasses important work to test customers' sensitivity to voltage and harmonic levels on the network. This work spans a number of projects and will inform the future evolution of national and European standards. This work will be shared with a wide variety of stakeholders including DECC, Ofgem and industry bodies.

4.3 Our demonstrators and deployment

We have undertaken a number of smart grid demonstrator projects notably our three Second Tier LCN Fund flag ship projects C_2C, CLASS and Smart Street. These demonstrations coupled with our First Tier trial projects act as a catalyst in the development, manufacturing, purchasing and installation of new devices and systems. These activities typically build upon work already underway in the IFI funded research and development area and help support our overall learning; critically they allow us to take proof-of-concept trials to deployable reliable solutions.

These demonstration projects also allow us to develop the framework needed to analyze smart grid costs and benefits, which is necessary to help build the business case for cost-effective smart grid solutions to our customers' needs.

The final development and deployment of new smart technologies has only been possible through our collaboration with several key partners notably, General Electric and Siemens in the area of advanced DMS development, Kelvatek in the development and adaptation of new LV network devices, The University of Manchester in understanding the performance of new systems and importantly Impact Research in understanding and determining the effects of these technologies on customers. Our work with these partners will provide a firm base for our future work on smart grid development and deployment.

4.4 Smart grid security

The dramatic increase in the distributed nature and complexity of network monitoring and control systems as smart grids are developed requires organisational adjustment through the development of people, processes and technologies. Smart grids will expose networks to new dynamic threats which are constantly changing and unpredictable. Information technology security and system reliability and maintainability form key risk considerations for us in our development of a smart grid. We will continue to hold security amongst our highest priorities and work with peers to develop the necessary standards and systems required. We already carry our regular aggressive intrusion testing of all our systems and will extend this rigour to our new smart grid systems.

4.5 Harnessing the benefits of smart metering

The benefits of GB adoption of smart meters will mirror that seen in a number of countries where such technologies are already in place. These benefits will accrue to customers initially via Supply businesses and then latterly through Network Operators. We believe that smart meters have a significant role to play in serving as a platform for a variety of service and cost improvements.

In the early period of the roll out programme, immediate benefits such as reduced meter reading costs and access to time based tariffs will be realised by customers. Under our predicted DECC low load growth scenario the benefits to customers from network operators will be less immediate but will eventually include such things as improved network visibility resulting in reduced or deferred network reinforcement costs; improved management of power outages resulting in better overall system availability; improved connection processes, reduced costs for micro generation customers, access to the commercial opportunities offered by demand side response, network losses reduction and improved customer service across a range of routine activities. Critically the period between 2015 and 2023 will be the bedding in period and their full integration into our future systems in preparation for wider scale adoption of low carbon technologies and hence greater demand growth. Our smart metering strategy, annex 28, outlines our plans to realise the benefits of smart meters for our customers in more detail.

4.6 Working with all stakeholders

Stakeholder involvement in and engagement with our innovation activities is essential in allowing us to successfully identify emerging R&D needs, for sharing of lessons learned, for continuous improvement and allowing the exchange of technical and cost data. Information obtained from our innovation project portfolio is shared through a variety of dissemination channels; for example via our website[5], at various dissemination events, in numerous whitepapers etc. This information helps to inform decision makers about smart grid technology options and thus facilitate their adoption.

4.7 In-house capability

4.7.1 Research and development

Research and development investments are being made to advance smart grid functionality by developing innovative, next-generation technologies and tools in the areas of control, monitoring, operations, investment planning, power electronics, cyber security and the advancement of precise time-synchronized measures of key parameters across the distribution network. Further research is planned into the behaviours and expectations of our customers and key stakeholders to help us develop appropriate response to future challenges.

4.7.2 Policy and standards

[5] www.enwl.co.uk/thefuture

Our Policy and Standards activities ensure that all new devices, techniques and commercial offerings will successfully integrate with existing legacy assets. The development of the company, UK, European and international standards are essential to create a secure and reliable framework for the deployment of innovative digital and engineering technologies throughout the electricity delivery system.

Planning and operating standards, such as ENA Engineering Recommendation P2/6 are a focus area for our work and we are leading the review of these industry design standards together with their operational equivalents. Our starting point is to maximise the value of the assets customers have already paid for and that are already in the ground. This approach coupled with trialling new technologies such as storage and adaptive protection systems will we believe be the key to unlocking existing network capacity for use by customers during RIIO-ED1 and the early part of RIIO-ED2.

The rapid evolution of standards such as P2/6 needs full engagement with and support from all stakeholders. Our customers hold security of supply as their number one priority and hence any change in this area must have their full support. Nevertheless it is already clear from the smart grid demonstrator projects C_2C and Flexible Plug and Play[6] that capacity can be released without jeopardising security of supply; indeed C_2C has already shown that both security and capacity can be increased simultaneously at much lower cost than previously thought possible.

4.7.3 Training and development

Any business depends on its people to deliver the services needed by its customers and Electricity North West is no different, so the development and training of our staff and contractors in smart grid technologies forms a key part of our plan.

Our workforce development plan addresses the impending workforce shortage by developing a greater number of well-trained, highly skilled power sector personnel that are knowledgeable in smart grid operations. Our recently commissioned Power Training Academy and our ongoing partnerships with universities and manufacturing entities that perform part of the research, development and deployment supply chain are essential to developing a smart grid capable work force.

4.8 Use of innovation funding

The Innovation Funding Incentive (IFI) introduced by Ofgem in DPCR4 successfully encouraged network operators to invest in the research and development of its key activities. In DPCR5, alongside IFI, Ofgem launched its Smart Grid, Smart Metering and Low Carbon Networks (LCN) funds to stimulate the industry to respond to the carbon challenges agreed by government. In particular, the LCN Fund is designed to promote innovation, trial and deployment of new technologies, commercial mechanisms and techniques.

In 2015 with the introduction of a new eight year distribution price control period, we will see the introduction of a new innovation funding mechanism; the Network Innovation Allowance (NIA) intended to replace IFI and the First Tier element of the LCN Fund and the Network Innovation Competition (NIC), the successor to the Second Tier of the LCN Fund to further support flagship demonstrator projects. In both cases, the funding will rely on the submission of an innovation investment plan with a clear emphasis on delivering specified output measures whilst ensuring good value for customers.

At Electricity North West we have and will continue to use this vital funding to develop the technologies and commercial techniques required to make the smart grid a reality. In our innovation strategy we have outlined how we involve our stakeholders in the development of our innovation plans, govern the delivery of real solutions to customers' needs through smart grid technologies and transform our network towards our vision.

[6] A Second Tier LCN Fund Project being delivered by UK Power Networks.

5. Technology work areas

Our technology development work spans a wide range of themes many of which are focused on asset management. These are detailed in our innovation strategy however those areas of work that are specifically smart grid focused are outlined below.

5.1 Network configuration

We are actively exploring the opportunities offered by dynamically reconfiguring networks to run in interconnected (or commonly referred to as meshed) as opposed to radial configurations. Our work has shown that such configurations offer significant benefits in terms of capacity release, power quality, losses reduction and security of supply.

The required technologies include advanced network automation and we are the leading network operator in this rapidly developing area of work. Meshing also requires advance real time power flow and contingency analysis techniques and the deployment of new network devices such as the WEEZAP[7] and LYNX[8] devices developed under our Smart Street project.

5.2 Voltage control and regulation

We have a number of projects exploring advance voltage control and regulation technologies both through the enhanced usage of existing tap changers and from deploying network capacitors. The benefits of these technologies are very significant in terms of capacity release, peak demand management, losses optimisation and conservation of energy. Full realisation of their benefits is in large part dependent on the availability of smart meter data.

5.3 Network optimisation

Advanced network automation and energy resource management will require the development, testing and implementation of new network optimisation technologies to ensure the optimum efficient level of network service. These technologies fall into two broad categories; site based deterministic systems and centrally based generic optimisation systems. Our work indicates that the latter offers significantly greater benefits for customers in the medium to long term and is the focus of our work. The former technology is being explored by a number of other network operators including Scottish & Southern Power Energy Networks and Scottish Power Energy Networks and we are closely monitoring their trials.

5.4 Fault level management

We were the first network operator in the UK to deploy a fault current limiter device in a live substation. We have continued to develop a number of new innovative solutions to fault level issues caused by both the level of demand and generation connected to the network. These projects are part of our short to medium term trial work.

5.5 Protection systems

Protection systems are an essential safety component in any power network and we are actively working on how these systems will need to evolve to manage the establishment of large volumes of distributed generation and new sustained loads such as electric vehicle charging. This work spans all network voltages from low voltage to the 132kV level.

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[7] A remotely controllable retrofit LV vacuum circuit breaker that replaces a standard J type fuse in a distribution board. The WEEZAP is a Kelvatek product and further information is available at www.kelvatek.co.uk/weezap.php.

[8] A remotely controllable retrofit LV switch that replaces a solid link in an underground link box. The LYNX is a Kelvatek product and further information is available at www.kelvatek.co.uk/lynx.php.

5.6 Network simulation and modelling

The ability to forecast the behaviour of power systems will become increasing important as power flows increase in both volume and complexity. We are working to develop new tools and techniques to understand this challenge and produce deployable tools for use by engineers and by our customers. This work is closely linked to our work on standards and forms part of our work in early RIIO-ED1.

5.7 Sensing and automation

Smart grids are in part about increased visibility and control of our networks and this will require the use of additional sensors fitted at strategic points across our network to provide in real-time accurate information on network status and capacity. With the introduction of increased capability to control remotely network devices such as switches allows us to actively manage the network to optimize its response and promote greater access at lower cost. Such sensors are complementary to the data obtained from smart meters but gather additional information such as harmonic content when required.

5.8 Storage

In conjunction with the University of Durham and the ENA Energy Storage Operators forum we are collaborating with all the DNOs to evaluate the various storage technologies, their operational characteristics and economic viability. Other DNOs are leading field trials in this area and we are monitoring these closely. Our forecast shows that these technologies will only have a niche role until the early 2020s and hence they do not feature as field trials in our near term work plan.

5.9 Integration to customers' systems

Domestic and I&C customers' internal systems will become increasingly complex and able to interact with the local power grid. We are working with social landlords on the utilisation of aggregated domestic DSR and with I&C customers on integration to their systems. This work will increase over the coming period as technology systems within building evolve to a state where they can respond without affecting customers' perception of comfort. Core to this work is the use of smart meter data as both a sensing media and as the platform for price response signals.

6. Benefits for customers

We have summarised in Table 2 below the financial benefits for customers included within our business plan and those they will receive in subsequent periods.

Table 2: Innovation funding and customers' benefits

Benefit area	RIIO-ED1 period value £m	Savings included in RIIO-ED1 Bus Plan	RIIO-ED2 period value £m	RIIO-ED3 period value £m
Network operation	71.4	Yes	107.1	133.9
Planning and design – reduced connection cost	0.5	Yes	0.8	1.1
Network capacity	10.6	Yes	15.9	19.9
Benefits within plan	82.5			

These benefits are based on our best view scenario which aligns with the DECC Low scenario. These benefits therefore represent the lower end of the benefits range and in the event of higher LCT adoption rates then benefits will rise proportionately. Under the higher scenarios, benefits related to network capacity investment will more than double.

It is of note that the efficiency incentive mechanisms applicable during the RIIO-ED1 period provide a strong incentive for the continued development of innovative solutions to generate savings for customers. This efficiency incentive will drive further benefits for customers as we continue to develop our smart grid and smart meter strategies to secure further savings for all stakeholders.

ANNEX 14: EFFICIENCY ASSESSMENT COMPARED TO OTHER DNOS

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Contents

1. Executive Summary

We took the preparation of both our July 2013 business plan and this amended business plan very seriously. We have undertaken a huge amount of work assessing the potential for efficiency improvements. Ofgem's analysis broadly supports our case that our plan is an efficient one, with a few exceptions that we discuss in this document.

Ofgem's analysis showed us to be upper quartile based on its totex analysis but to be outside of the upper quartile in its bottom up assessment. Ofgem's choice of weighting of bottom up and top down models in its overall assessment had a material effect on the overall assessment of our plan in Ofgem's Fast Track analysis.

We asked Oxera to review Ofgem's totex models, along with other credible alternative totex models. Oxera concludes that, overall, Electricity North West is more efficient than an upper-quartile benchmark and is ranked first of six at the DNO ownership group level, on average, across various measures, and third of 14 at a licensee level. Oxera also concludes that Ofgem's totex models under-estimate the efficiency of our plan compared to other totex models.

Within Ofgem's bottom up analysis, it is clear that inappropriate analysis of a small number of activities has had a disproportionate effect on the assessed efficiency of our plan. Our analysis shows that the vast majority of what Ofgem has identified as inefficiency in our plan was actually due to either inappropriate cost assessment approaches or failure to make qualitative adjustments to modelling results to take account of strong evidence submitted elsewhere in our plans.

In particular, we have identified significant issues with the assessment of the following activities:

- asset replacement – the results of which are distorted by inappropriate assessment of required volumes due to 'cherry picking' and lack of qualitative adjustments, and inappropriate selection of 'expert view' unit costs
- business support - two assumptions in Ofgem's Business Support analysis materially distort the results of Ofgem's analysis: its incorrect treatment of fixed costs and its inappropriate exclusion of insurance costs
- refurbishment – which was based on very simple comparisons of DNOs' intervention rates and took no account of trade-offs due to differences in companies' asset management strategies

We recommend that Ofgem makes a small number of important changes to its cost assessment approach for slow track companies to address these material issues.

We have reviewed our plan in great detail in preparation for resubmission and have undertaken substantial analysis to assure ourselves that our revised plan represents an efficient and well justified proposition for customers to fund. We have removed costs where new evidence suggests that the costs included in our July 2013 plan were inefficient. We have removed more than £37m of costs from our plan. Our analysis shows that we can expect our revised plan to be assessed to be upper quartile across all activity areas and to be comfortably within overall upper quartile, when assessed via a range of assessment tools that includes the small number of key changes set out in this annex.

We are confident that our resubmitted plan represents an efficient proposition for our customers in the North West to fund.

2. Our approach to ensuring that our costs were well justified in July 2013

We undertook a substantial amount of analysis as part of developing our July 2013 plan to test that our submission was efficiently priced. The detailed analysis that we presented in our previous plan can be found in Appendix 1.

A summary of how we expected our plan would be assessed is shown in the table below. As Ofgem's document 'Assessment of the RIIO-ED1 business plans', published as part of Ofgem's fast track assessment stated that "*our central view does not include any adjustment for ENWL's view of 'fixed costs'", w*e show analysis prior to fixed cost adjustment here to allow an appropriate comparison.

Electricity North West Analysis - July 2013

		Before fixed cost adjustment *3		
		Totex analysis	**Mid level activity analysis**	**Unit cost comparisons**
Average efficiency	Network Investment *2	95%		86%
	Network Operating costs		89%	83%
	Closely associated indirects		71%	
	Business support costs		95%	
Total against upper quartile *1		100%	87%	96%

*1 – For mid level and unit cost based analysis upper quartile is based on sub-set of activities and may therefore represent a target that is more stretching than true upper quartile

*2 – Unit cost comparisons presented for lower voltage asset replacement only

*3 – Unit cost model developed by Cost Assessment Working Group includes embedded fixed cost adjustment

Ofgem published its analysis of the relative efficiency of DNOs' plans in December 2013. Ofgem's analysis models for its bottom up analysis were quite different to those we used in preparing our July plan and therefore it is difficult to draw a direct comparison. The following table summarises Ofgem's analysis in a format as close as possible to our original analysis.

Ofgem analysis - December 2013

		Totex analysis (average of two models)	**Bottom Up analysis**
Average efficiency	Network Investment	96%	120%
	Network Operating costs		88%
	Closely associated indirects		81%
	Business support costs		128%
Total against upper quartile		100%	103%

As Ofgem used different analytical techniques to us and had access to DNOs' latest plans on which to base analysis, it is inevitable that results will differ slightly. However, we note that our prediction of the overall assessment of the efficiency of our plan at totex level was very similar to Ofgem's ultimate view. This shows that our clear focus on managing the total costs that we ask customers to pay for was successful. However, Ofgem's assessment of our activity level efficiency differed materially from our assessment for some activities. In particular, Ofgem assessed that our business support and network investment (particularly asset replacement) forecasts were inefficient.

3. How Ofgem assessed the efficiency of our July 2013 plan

3.1 Overall assessment

Ofgem used a range of cost assessment models in assessing the efficiency of DNOs' July 2013 plans. The three core models that it used comprised a bottom up model and two totex models. In combination, these were used to determine whether DNOs' plans were efficient.

DNO	submitted (net, inc RPEs)	Bottom Up	Totex Reg 72 (activity level)	Totex Reg 81 (high level)	Combined assessment[1]
ENWL	1,900	1,837	1,935	1,884	1,855
NPGN	1,365	1,278	1,333	1,367	1,296
NPGY	1,859	1,675	1,900	1,816	1,721
WMID	2,087	2,129	1,917	2,036	2,091
EMID	2,093	2,088	2,097	2,147	2,096
SWALES	1,084	1,169	1,077	1,161	1,156
SWEST	1,696	1,737	1,441	1,434	1,662
LPN	1,968	1,626	1,925	1,958	1,705
SPN	1,897	1,778	1,738	1,810	1,777
EPN	2,861	2,351	2,615	2,731	2,431
SPD	1,740	1,505	1,496	1,679	1,525
SPMW	2,220	1,759	1,485	1,400	1,680
SSEH	1,244	1,245	1,077	1,016	1,195
SSES	2,490	2,410	2,641	2,494	2,449

[1]Combined assessment weightings: 75% bottom up, 12.5% activity-level, 12.5% high-level

Source: Ofgem analysis, December 2013

Ofgem's combined assessment suggested that our July 2013 plan was £45m, or 2%, more expensive that its assessment of an efficient level of costs.

Ofgem's analysis suggested different levels of efficiency depending on the model used. All of Ofgem's models showed us to be within the top half of DNOs. One of Ofgem's totex models showed our plan to be within the upper quartile.

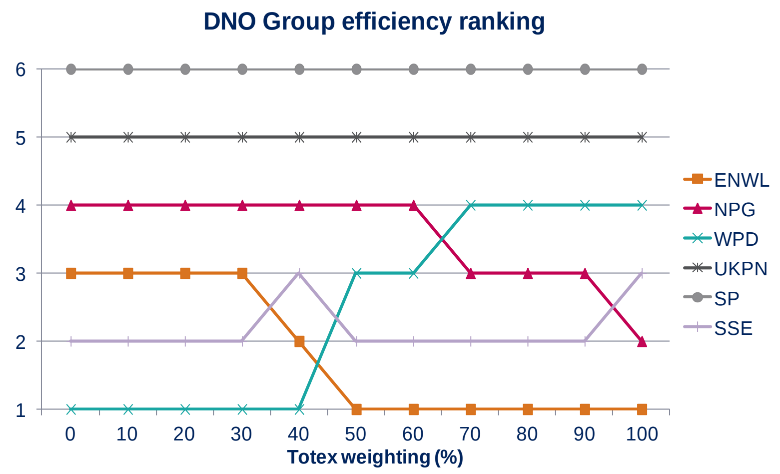
	Activity-level analysis	Totex activity-level drivers	Totex high-level drivers	Combined assessment[1]
Efficiency	103%	98%	101%	102%
Rank (of 14)	7	3	6	6

[1]Combined assessment weightings: 75% activity-level analysis, 12.5% Totex activity-level drivers, 12.5% Totex high-level drivers

Source: Ofgem analysis, December 2013

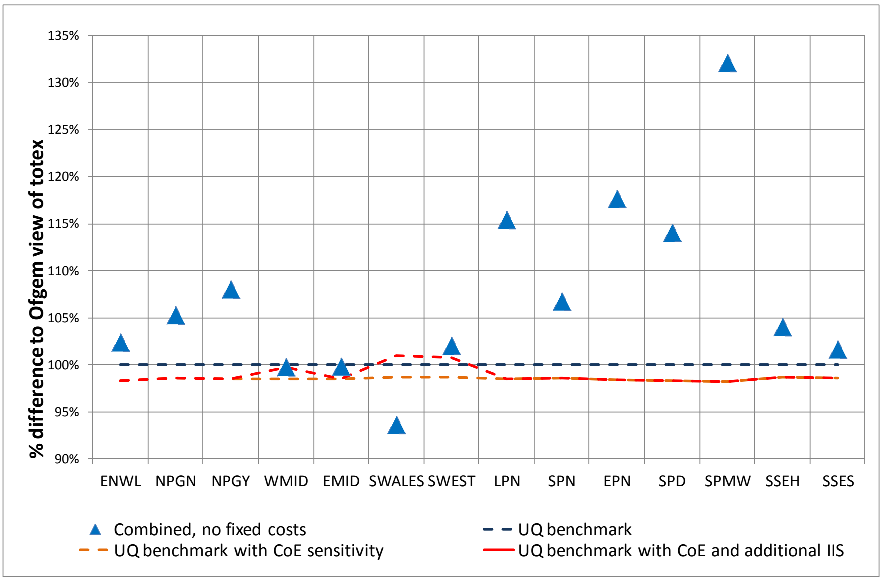
All modelling techniques have advantages and disadvantages. We agree, therefore, that it is appropriate for Ofgem to use a range of models to assess the efficiency of companies' plans. When using a range of models, however, it is important to carefully consider how the results from various models should be combined to reflect the findings from all models.

Ofgem's overall assessment of our plan was that it was slightly outside of its assessed efficient level of costs. This conclusion was materially affected by Ofgem's choice of weighting of totex and bottom up models. The following figure demonstrates how sensitive Ofgem's overall assessment is to the weighting of bottom up to totex models. This clearly shows that if Ofgem had opted to weight its totex models at 50% or more of its overall assessment we would have been ranked as the number 1 group. We note that Ofgem used a 50% weighting for totex models in its RIIO-GD1 analysis.



The analysis presented in this paper considers the relative merits of Ofgem's chosen models. We do not find evidence that Ofgem's bottom up model is superior to its totex model, and discuss several of the issues with the bottom up approach in this annex. Our analysis also shows that Ofgem's totex models are as statistically valid as those used in the DPCR5 review, and those used by other regulators.

Ofgem additionally considered DNOs' cost performance together with cost of equity assumptions and monetisation of outputs. This analysis suggested that our forecast was around £77m, or 4%, higher than Ofgem's view of efficient costs.



On the basis of its analysis, Ofgem assessed that our plan was not sufficiently well justified to be Fast Tracked.

3.2 Totex analysis

Ofgem assessed that our plan was efficient at totex level, when assessed against the average of its two totex models. This result was achieved through our efforts to reduce costs for customers by ensuring all aspects of our plan were robustly tested prior to inclusion in our plan.

Ofgem used two totex models to assess the efficiency of DNOs' plans. The results obtained from the two models give slightly different results.

		Ofgem totex models	
	ENWL forecast	Totex Reg 72 (activity level)	Totex Reg 81 (high level)
£m	1900	1935	1884
Efficiency %		98%	101%

The results of totex models can vary depending on assumptions such as model specification, functional form, data set, etc. We asked Oxera to examine a range of alternative totex models to test that this result was not a feature of the model specification.

Oxera considered the results of a range of models against three measures:

- **Average efficiency over the RIIO-ED1 period corrected to the upper-quartile benchmark**—this measure is commonly used (including by Ofgem) to assess whether a company's totex is efficient or otherwise relative to a benchmark. Oxera has used the average efficiency estimated over the RIIO-ED1 period corrected to the upper-quartile benchmark across the 48 sets of models to rank the companies' performance on this measure.
- **Percentage of times a DNO is better than the benchmark**—this measure is intended to capture the consistency of a company's performance across the 48 models, as assumptions underlying some models (i.e. model specification, estimation technique, etc.) may be more beneficial to some companies than others. This may mean that they are assessed to be significantly above the benchmark under these models, which might be masked in the first measure.
- **Average rank across the benchmark—**this measure is intended to address a limitation with the first two measures in that they do not take into account circumstances where the range of efficiencies estimated (across the industry) from a model is wide and the upper-quartile benchmark is quite low, such that even a company that is ranked poorly (e.g. in the bottom half) is assessed to be performing efficiently.

Oxera's analysis can be found in Appendix 2.

Based on empirical analysis of the 48 sets of models considered in Oxera's report, including Ofgem's core models and its sensitivities, Oxera draw the following conclusions on Electricity North West's efficiency:

- At the ownership group level Electricity North West is ranked first of six on average across the three measures considered.
- At the licensee level, while there is no single DNO that overwhelmingly dominates the others, Electricity North West and Northern Powergrid Northeast are the only DNOs that are almost always estimated to be better than the benchmark (in almost 90% of the examined models). Electricity North West is ranked second of 14 on this measure. In addition, Electricity North West, Northern Powergrid Northeast and

WPD South Wales are the only DNOs to be ranked in the top quartile on all three measures, and Electricity North West is ranked third of 14, on average, across the measures.

Oxera concludes that “*Overall, the analysis carried out in this report demonstrates that ENWL is more efficient than an upper-quartile benchmark and is ranked first of six at the DNO ownership group level, on average, across various measures, and third of 14 at a licensee level*”.

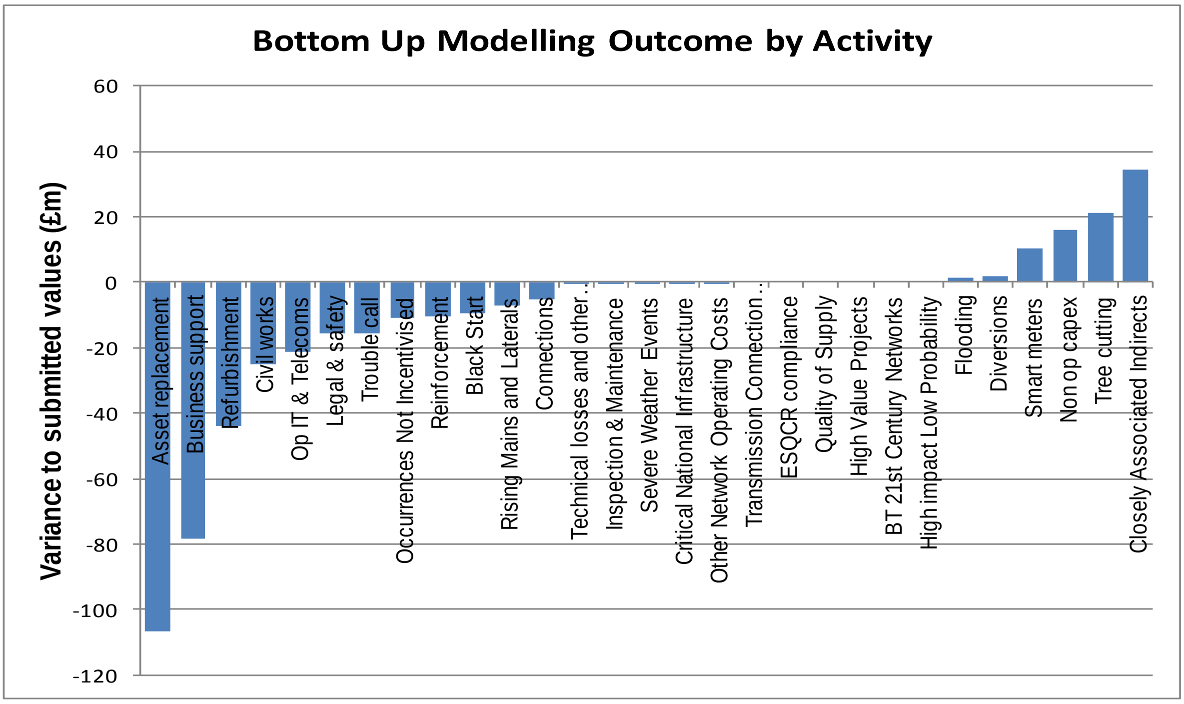
When using the historical data only, of the only two instances when Electricity North West is estimated close to, but not better than, the benchmark, one result comes from Ofgem’s model specification (Electricity North West is estimated to be 2% worse than the benchmark), while Ofgem’s other model specification estimates Electricity North West to be at the benchmark. That is, of the only two specifications used by Ofgem, both place Electricity North West at the bottom end of the efficiency range estimated across all of the specifications examined in Oxera’s report. This suggests that Ofgem’s totex models under-estimate the efficiency of our plan compared to other totex models considered in Oxera’s report.

We recommend that Ofgem considers using the alternative totex models considered in Oxera’s report for its slow track assessment to supplement its totex analysis.

3.3 Bottom Up analysis

Ofgem’s bottom up analysis approach assessed the efficiency of specific activities included in our plan using individual models. These models comprised a combination of regression models and spreadsheets that separately considered volume and unit cost efficiencies. The results of those models were then aggregated to determine the overall efficient cost associated with Ofgem’s bottom up models.

The following graph compares the results of Ofgem’s bottom up analysis, by activity, to the costs included in our July 2013 submission.



It is clear from this graph that Ofgem's assessment of a small number of activities has a disproportionate effect on our assessed efficiency. In particular, Ofgem assessed that our proposed costs associated with asset replacement, business support and refurbishment activities were inefficient.

We have reviewed Ofgem's bottom up efficiency analysis in detail. The following sections of this annex review Ofgem's approach to cost assessment in these areas. We consider whether Ofgem's analysis has indeed identified inefficiencies in our plan or whether the results arise from shortcomings in Ofgem's analysis approach.

3.3.1 Asset Replacement

While many aspects of Ofgem's assessment of asset replacement are logical, two aspects of Ofgem's approach have resulted in an inappropriate assessment of the efficiency of our proposed costs:

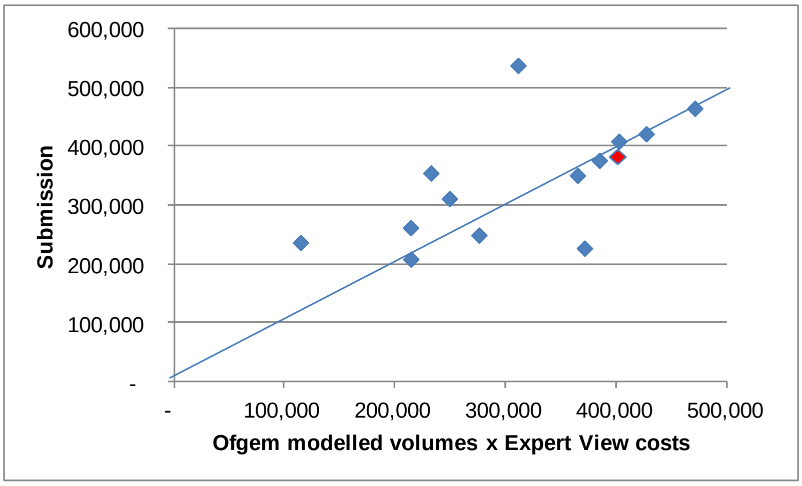
- inappropriate assessment of required volumes due to 'cherry picking'; and
- lack of qualitative adjustments, and inappropriate selection of 'expert view' unit costs.

In the following paragraphs we set out the effect of these very material issues

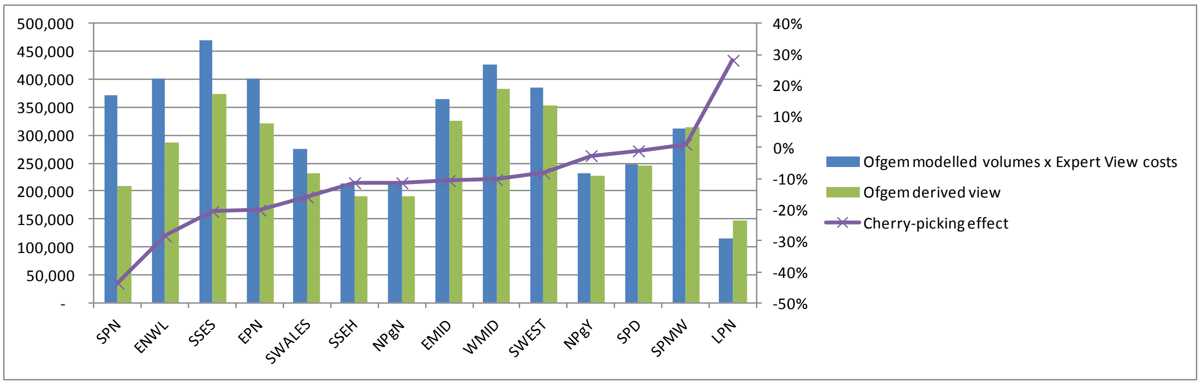
3.3.1.1 'Cherry picking' of asset replacement volumes

Ofgem's approach to assessing the required volume of asset replacement activities is generally based on allowing the DNO the lower of Ofgem's modelled view of the required volumes and the DNO's view. As this assessment is undertaken at the level of individual asset classes, no account is taken of the extent to which the DNO may address network health needs via varying its programme between asset classes.

We have analysed the outcome of Ofgem's models prior to it making its 'lower of' adjustment. The graph below compares companies' submitted asset replacement forecasts against Ofgem's modelled volumes multiplied by Ofgem expert view unit costs. The assessment of our forecast is highlighted in red. The graph clearly shows that our overall Asset Replacement submission aligns well to Ofgem's overall assessment of asset replacement needs. Indeed, Ofgem's unadjusted view would have allowed us over £20m more than the costs included in our July 2013 plan.



However, the effect of Ofgem's 'lower of' approach was to remove £114m, or 28%, from its overall assessment. The average proportion of Ofgem's overall assessment removed via cherry picking across all DNOs was just 11%. Despite the fact that our overall asset replacement plan compares favourably to Ofgem's overall assessment, we faced the second largest cherry picking effect of any DNO. This cherry picking materially and adversely reduced Ofgem's view of the efficiency of our plan.



Our analysis suggests that we face this disproportionately large cherry picking adjustment because we undertake a particularly thoughtful approach to developing our asset replacement programme. Ofgem's models generally utilise median intervention rates in establishing the comparator baseline. Notwithstanding modelling issues relating to substitutable assets (eg LV cable), this approach penalises those areas where more extensive (and cheaper) refurbishment options are being proposed by not crediting the avoided replacement costs. Even where intervention rates above median are fully justified based on network circumstances, and justified using the risk indices and associated CBA analysis, Ofgem did not take this into account.

Our Condition Based Risk Management approach to developing our network investment programme, supplemented with detailed cost benefit analysis and detailed work scheduling, results in the makeup of our programme being different to that of other DNOs. Some aspects of our forecast also differ to the activities that we undertook in DPCR5, for example we have undertaken a substantial programme of woodpole asset replacement programme during DPCR5 and co-ordinated the activity with our ESQCR programme to maximise the benefit from both programmes. Our focus on this asset class during DPCR5 means that we need much lower volumes of work to be undertaken during RIIO-ED1, now that our ESQCR programme is largely concluded. We remain convinced that the volume of asset replacement included in our July 2013 plan remains appropriate for customers to fund during the RIIO-ED1 period and is well justified.

We accept that it will always be difficult for Ofgem to develop models that take account of all the complexities of developing detailed asset replacement forecasts. It is important, therefore that Ofgem supplements its models with detailed qualitative assessment of companies' forecasts and, where evidence exists to do so, adjusts the results of its models. These adjustments must take account of interactions between different parts of the cost base, especially between asset replacement and refurbishment.

We note that Ofgem did make some qualitative adjustments to our forecasts in its assessment of our July 2013 plan; however it only made adjustments in a small number of asset classes and it never fully restored the volumes to the proposed levels.

We have enhanced the CBA analyses provided for asset replacement and linked them to a discussion of the resulting risk profiles in Annexes 2B and 3 to better explain our proposals and their justification.

3.3.1.2 Selection of 'expert view' unit costs

Ofgem's unit cost analysis for asset replacement is based on comparisons of median unit costs achieved by all DNOs during DPCR5 and those forecast for the remainder of DPCR5 and for RIIO-ED1. In many cases, its assessment of unit costs is logical. However, in a number of cases, Ofgem's determination of 'expert view' unit costs is distorted by two key issues: use of inappropriate combinations of unit costs for an asset type to create an impossible overall 'unit cost', and inappropriate aggregation of unit costs across some asset categories.

Ofgem's selection of 'expert view' unit costs is generally based on selecting the lowest unit cost suggested by actual unit costs achieved in DPCR5 to date, actual unit costs forecast for the last two years of DPCR5 or the unit costs forecast for RIIO-ED1.

Some unit costs associated with the same asset or group of assets can be distorted by the reporting boundaries adopted by DNOs. In these cases, choosing unit costs from different DNOs or different time periods for the same asset can result in impossibly low unit costs. For example, in the case of unit costs associated with 132kV towers, Ofgem has chosen to use unit costs from different DNOs in different time periods for tower lines and for the associated fittings and conductors. The combined 'unit cost' resulting from this approach is lower than is suggested in any one time period for any DNO.

In some cases, Ofgem has aggregated asset classes in setting unit costs and applied a single unit cost across the combined asset class. This approach disadvantages companies that propose to install any assets that have higher unit costs than are proposed for the combined class.

We agree that there are many asset categories that can be aggregated for the purposes of assessing appropriate volumes, particularly where there is a degree of potential substitution between categories, or where obsolete categories need to be considered against their modern equivalents, for example when considering all categories of LV cables. However, in assessing unit costs, it is essential that Ofgem undertakes unit cost assessment at a more detailed level.

Ofgem's approach to aggregating asset classes has a particularly adverse effect on the assessment of our plan in the case of 132kV switchgear. For this group of assets, Ofgem aggregated all types of switchgear when assessing both required volumes of work and unit costs. We accept that it is appropriate for Ofgem to consider the whole 132kV circuit breaker population when assessing future volumes of work and intervention rates. However, a blended unit cost between gas insulated switchgear (GIS) and air insulated switchgear (AIS) types is inappropriate as it does not allow a true like-for-like comparison. In this example, the plant costs for AIS are significantly cheaper, but AIS solutions require far more cabling, land & ancillary equipment. These additional costs are not picked up in a unit cost analysis, but would emerge in a discussion of options for individual schemes. Where appropriate, our scheme papers for 132kV projects set out our analysis of why GIS or AIS solutions are appropriate in each case.

We accept that Ofgem will want to test that DNOs are not inappropriately proposing to install more expensive equipment than is necessary, however we believe that this assessment should be based on analysis of DNOs' cost benefit analysis and, where appropriate, scheme papers, rather than over-simplified averaging.

We recognise that in a small number of cases, for example 33kV transformers and high voltage circuit breakers, Ofgem's analysis has identified that our proposed unit costs were a little high. Where Ofgem's analysis has identified that our unit costs were not as efficient as those of other DNOs we have made changes to our resubmitted plan.

3.3.2 Business Support

Two assumptions in Ofgem's Business Support analysis materially distort the result and Ofgem's view of the efficiency of our costs:

- treatment of fixed costs; and
- exclusion of insurance costs.

In the following paragraphs we set out the effect of these very material issues as well as exploring a number of other concerns that we have with Ofgem's approach to assessing cost associated with this activity.

3.3.2.1 Incorrect Treatment of Fixed Costs

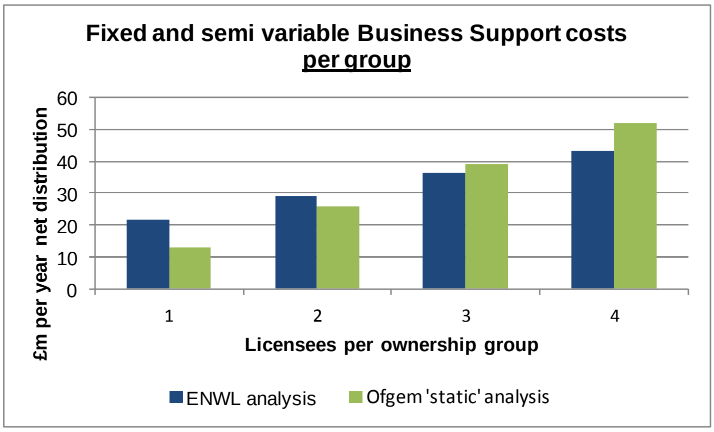
Electricity North West is the only DNO that is in an ownership structure that does not contain another DNO. Analysis based on 14 licensees will not appropriately calculate the level of fixed costs that would be required for an efficient single licensee (because all other DNOs belong to ownership groups that include multiple DNOs).

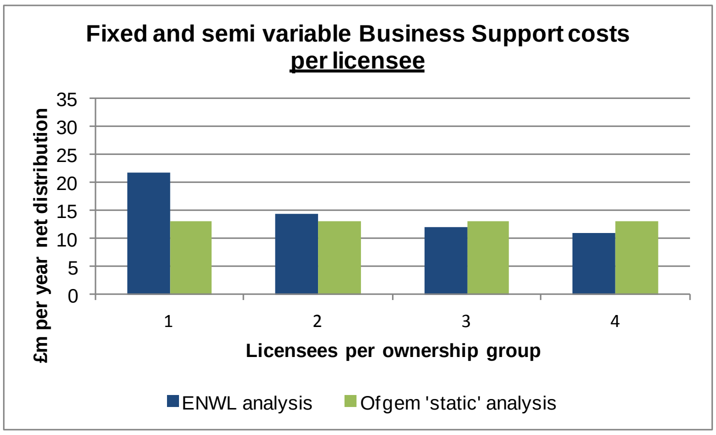
We asked KPMG to analyse the level of fixed costs that a single licensee would incur above the level that would be expected of DNOs in an ownership group that included two DNOs. KPMG's report estimated that the fixed cost uplift which Electricity North West should be afforded relative to other DNOs as a result of its single licence status is £10.5m per year. We included this report in our July 2013 plan and are pleased that Ofgem recognised this as a "*well presented report*". Details of KPMG's analysis can be found in Annex 29.

Ofgem's bottom up analysis of our proposed business support costs as part of its fast track decision suggested that efficient business support costs for Electricity North West are £177m (2012-13 prices, net distribution, 8 year total, including real prices effects). Our plan included £255m of business support costs. Ofgem therefore suggested that our proposed business support costs were 44% higher than a modelled efficient level of costs.

As part of its analysis Ofgem made a normalisation adjustment to remove £13m per licensee from business support costs. In doing so, it effectively assumed that costs were fixed by licensee and no costs could be shared between companies.

The following graphs show how the level of fixed and semi variable costs removed in Ofgem's normalisation compare to the level identified in KPMG's analysis. We have extrapolated KPMG's analysis to show 3 and 4 licensee groups. It is clear that Ofgem's normalisation differs significantly from KPMG's and that at a licensee level, Ofgem's approach will particularly distort the efficiency results of single licensee groups.





Ofgem's business support cost assessment model does not currently include a facility to remove different levels of fixed costs per group; it simply allows removal of the same value per licensee or per group.

We asked Oxera to undertake analysis to test the sensitivity of results of Ofgem's modelling to different assumptions in fixed cost normalisation, using the following scenarios:

- £13m per licensee – as in Ofgem's fast track analysis
- No fixed cost adjustment
- £23m per ownership group – twice KPMG's identified fixed cost uplift between a single and two DNO group

The results of Oxera's analysis show that Ofgem's business support analysis is hugely sensitive to its fixed cost assumptions, and that more appropriate assumptions would result in modelled efficient costs for Electricity North West being more than £75m higher.

Fixed costs - results

£m ED1 2012-13 prices		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Static	Efficiency %	-47%	-24%	29%
	Allowance	184.5	190.8	261.7
Monte Carlo	Efficiency %	-25%	-22%	6%
	Allowance	184.9	192.8	262.1

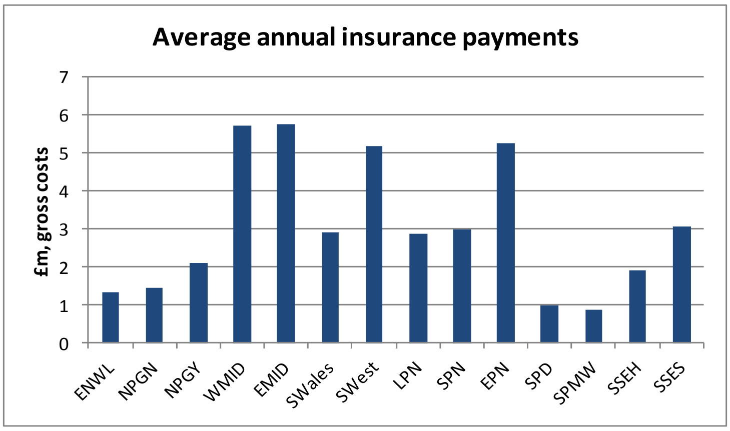
Fixed costs - variance

£m ED1 2012-13 prices		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Static	Efficiency %	N/A	23%	76%
	Allowance	N/A	6.2	77.2
Monte Carlo	Efficiency %	N/A	3%	31%
	Allowance	N/A	7.9	77.2

The detailed results of Oxera's analysis can be found in Appendix 3.

3.3.2.2 Inappropriate Exclusion of Insurance Costs

Ofgem's cost assessment approach removed insurance costs from Business Support analysis. Analysis of DNO forecasts shows significant variation in the level of insurance costs included in companies' plans submitted in July 2103. These differences could be due to a number of reasons for example companies' chosen risk balance, company specific factors as well as the efficiency of insurance costs.



We have undertaken considerable work to seek to get the risk to cost balance optimised to minimise costs for customers. Our approach is reviewed regularly as insurance costs change and as our view of risks evolves. This approach to managing this important aspect of our cost base led to us including the third lowest insurance costs of any DNO for RIIO-ED1.

Ofgem's approach took no account of the 'trade-offs' that are considered by companies in deciding on the level of insurance purchase. For example, companies may take out vehicle insurance or may instead choose to 'self insure' and would therefore forecast associated costs within 'vehicle and transport'. Similarly, companies may take out machinery breakdown cover or instead may forecast higher levels of Troublecall or asset replacement costs. Companies that concluded that the lowest cost approach is to carry more risk will have been 'penalised' for higher costs in these alternative areas of spend while getting no 'credit' for lower insurance costs.

Ofgem's document setting out its approach to cost assessment for Fast Track stated that "*an efficient view of costs associated with these activities has been added back to our benchmarked expenditure assessment*". We see no evidence of this having been undertaken; companies with inefficient levels of insurance costs included in their plans will have therefore not incurred any penalty.

A more appropriate approach would be to not remove insurance costs from assessment, and in doing so ensure both sides of risk balance are included in Ofgem's bottom up model and to test efficiency of insurance activity. Any insurance that is only incurred by one licensee for company-specific reasons can be subject to separate qualitative review and adjustment.

We asked Oxera to undertake analysis to test the sensitivity of results of Ofgem's modelling to insurance normalisation.

The results of Oxera's analysis show that Ofgem's business support analysis is very sensitive to its insurance normalisation assumption, and that more appropriate assumptions would result in modelled efficient costs for Electricity North West being more than £25m higher. The extent of the movement in Ofgem's Monte Carlo model is greater than in Ofgem's static model due to a spreadsheet error in Ofgem's Monte Carlo model.

Insurance - results

£m ED1 2012-13 prices		Insurance excluded from modelling	Insurance included in modelling
Static	Efficiency %	-47%	-31%
	Allowance	184.5	203.0
Monte Carlo	Efficiency %	-25%	-15%
	Allowance	184.9	209.9

Insurance - variance

£m ED1 2012-13 prices		Insurance excluded from modelling	Insurance included in modelling
Static	Efficiency %	N/A	16%
	Allowance	N/A	18.4
Monte Carlo	Efficiency %	N/A	10%
	Allowance	N/A	25.1

The detailed results of Oxera's analysis can be found in Appendix 3.

3.3.2.3 Endogenous cost drivers

Ofgem's business support assessment approach used a composite scale factor comprising a number of endogenous scale drivers. This approach of using factors that are significantly within companies' control, such as companies' proposed costs or revenues, has the potential to reward companies for inefficient operating structures or proposing high prices for customers.

For its slow track assessment, Ofgem must either use exogenous cost drivers such as the high level scale drivers like MEAV (as used in totex composite for business support costs), or it must adjust its endogenous cost drivers to remove this distortion.

It is not possible for us to calculate the effect of using endogenous cost drivers on the results of Ofgem's fast track analysis as we do not have access to efficient cost drivers for other DNOs.

3.3.2.4 External benchmarks

We note that Ofgem's report 'RIIO-ED1 business plan expenditure assessment - methodology and results' suggests the potential for Ofgem to use external benchmarking data for slow track companies.

We asked Oxera to evaluate Ofgem's proposed approach to using external benchmarks. Oxera identified a number of important issues associated with this possible approach including:

- Costs can differ dramatically due to accounting rules, sector specific needs, cultural differences and legislation
- The comparator group used in GD1 and T1 is much larger than most DNOs and may not provide like-for-like comparison
- Most external databases collect and hold data from business units of large companies and may exclude divisional and group costs
- It is likely that data from several sources may contain inconsistencies due to diverse data classifications, dissimilar accounting rules and differences in interpretation
- Organisations in external benchmark databases are likely to report on statutory opex basis rather than the cash basis that DNOs are required to use
- Use of single scale metrics to measure a whole business support function could result in crude simplification and exacerbate issues outlined above

For these reasons, we strongly recommend that Ofgem does not use external benchmarks as part of its slow track assessment.

Oxera's report can be found in Appendix 5.

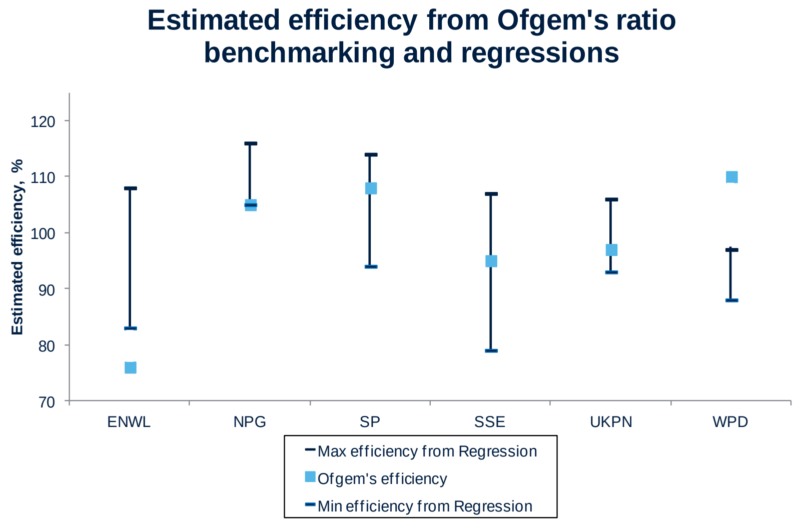
3.3.2.5 Alternative methods of assessing business support analysis

We asked Oxera to assess how the results from regression analysis differ from those of Ofgem's model.

Oxera developed a range of eight regressions based on combinations of:

- Cost driver: Ofgem's Business Support composite and MEAV (the driver for business support in Ofgem's activity drivers totex model)
- Licensee and group based analysis
- Logarithms and levels

The results of its analysis are shown on the following graph.



Note that in Oxera's analysis values of greater than 100 are more efficient.

In addition to demonstrating the sensitivity of results to the regression models chosen, Oxera's results clearly demonstrate that the results obtained from Ofgem's model are outside of the range of results obtained from regression analysis.

Oxera's analysis included four ownership group based models. On average, these models suggest that Electricity North West's modelled efficient costs should be some £48m higher than Ofgem's fast track analysis.

We recommend that Ofgem tests the results of its slow track analysis against group based regressions. If the results of Ofgem's model deviation significantly from the results of Ofgem's model it should consider whether the results are sufficiently valid to use for setting DNO cost allowances.

More details of Oxera's regression analysis can be found in Appendix 4.

3.3.2.6 Business support - overall

Ofgem's approach to assessing the efficiency of business support costs for fast track assessment was materially flawed.

The combined effect of changing the fixed cost assumptions and insurance normalisations to address the issues set out in sections 3.3.2.1 and 3.3.2.2 results in very material increases to the modelled efficient costs for Electricity North West.

Monte Carlo £m ED1 2012-13 prices		Fixed cost approach		
		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Insurance excluded from modelling	Efficiency %	-25%	-22%	6%
	Allowance	184.9	192.8	262.1
Insurance included in modelling	Efficiency %	-15%	-10%	13%
	Allowance	209.9	221.4	278.9

variance (£m) £m ED1 2012-13 prices		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Insurance excluded	Efficiency %	0.0	7.9	77.2
Insurance included	Allowance	25.1	36.6	94.0

Making the two changes we recommend to business support modelling would have a combined effect of increasing Ofgem's view of the efficient level of costs for Electricity North West by £94m. This represents a swing of more than 36% of our proposed costs for this activity.

This change in assessment has a further, secondary effect on Ofgem's bottom up assessment of our plan in that, because the results of all companies change when more appropriate modelling assumptions are used, the overall upper quartile also changes and further improves our assessed performance.

We believe that our assessed performance has been further distorted by Ofgem's use of endogenous cost drivers. As our plan was assessed as being very close to Ofgem's overall efficient level, and our proposed revenues were amongst the lowest of any DNO, other less efficient companies will have received higher business support cost allowances because Ofgem's chosen cost driver for less efficient companies would be larger and attract larger allowances.

We recommend that Ofgem makes changes to its cost assessment approach for slow track to address these very important issues.

We also recommend that Ofgem tests the results of its slow track analysis against ownership group based regressions. If the results of Ofgem's model deviate significantly from the results of Ofgem's model it should consider whether the results are sufficiently valid to use for setting DNO cost allowances.

3.3.3 Refurbishment

Ofgem's assessment of the efficiency of refurbishment volumes was based on very simple comparisons of DNOs' intervention rates. It took no account of trade-offs between, for example, refurbishment volumes and asset replacement volumes due to differences in companies' asset management strategies.

Ofgem's assessment of refurbishment costs was further distorted by the fact that companies have reported very different unit costs for refurbishment activities. In the case of many asset classes the differences in unit costs are sufficiently large to suggest differences in the level of intervention undertaken when companies refurbish assets or differences in interpretations of reporting rules rather than differences in efficiency between DNOs.

Ofgem's assessment approach also took no account of trade-offs between asset replacement and refurbishment in DNOs' asset management approaches. In a number of cases, the level of cherry picking adjustment in Ofgem's asset replacement assessment of an asset class was greater than the level of refurbishment cost disallowed from our plan. For example, Ofgem's cherry picked approach to asset replacement failed to allow us a greater than £8m 'credit' in asset replacement costs for 132kV towers, but at the same time the refurbishment assessment disallowed £5.5m of refurbishment costs for this asset type.

We accept that it will always be difficult for Ofgem to develop models that take account of all the complexities of developing detailed asset intervention forecasts. It is important, therefore that Ofgem supplements its models with detailed qualitative assessment of companies' forecasts and, where evidence exists to do so, adjusts the results of its models. These adjustments must take account of interactions between different parts of the cost base, especially between asset replacement and refurbishment.

We have refined the presentation of our cost benefit analysis and condition based risk management approach for our resubmitted plan to make clearer where trade-offs exist that should be considered in qualitative adjustments.

3.3.4 Other aspects of Ofgem's bottom up analysis

A number of aspects of Ofgem's analysis have been distorted by apparent differences in the interpretation of Ofgem reporting instructions. For example, it is clear that DNOs have interpreted the scope of civil cost 'units' quite differently. Some companies report a relatively small number of quite expensive pieces of work whereas others report a much higher number of relatively inexpensive pieces of work. The overall effect of Ofgem's assessment is to allow Electricity North West low volumes of inexpensive unit of work, resulting in a significant cut to our efficient proposals. Ofgem must ensure that it reviews companies' submitted data to identify such issues in resubmitted plans and, where found, takes account of the differences

We have also found a small number of spreadsheet linking issues and calculation errors, such as use of zero values in median calculations, in Ofgem's files. Some of these issues had quite material consequence for the assessment of our plan, for example Ofgem's analysis failed to add in £10.8m of efficient costs associated with service unlooping. We have identified these to Ofgem; Ofgem has acknowledged that such issues will be corrected for slow track analysis.

3.3.5 Overall

It is clear from Ofgem's bottom up assessment that inappropriate analysis of a small number of activities has had a disproportionate effect on our assessed efficiency. Our analysis shows that the vast majority of what Ofgem has identified as inefficiency in our plan was actually due to either inappropriate cost assessment approaches or failure to make qualitative adjustments to modelling results to take account of evidence submitted elsewhere in our plans.

In particular, we have identified significant issues with the assessment of the following activities:

- asset replacement – the results of which are distorted by inappropriate assessment of required volumes due to 'cherry picking' and lack of qualitative adjustments, and inappropriate selection of 'expert view' unit costs
- business support - two assumptions in Ofgem's Business Support analysis materially distort the results of Ofgem's analysis: its inappropriate treatment of fixed costs and its incorrect exclusion of insurance costs
- refurbishment – which was based on very simple comparisons of DNOs' intervention rates and took no account of trade-offs due to differences in companies' asset management strategies

We propose a number of changes to Ofgem's approach that will address these issues.

3.4 Fixed cost sensitivity

Ofgem's published fast track assessment document 'Assessment of the RIIO-ED1 business plans' states that "*Whilst our central view does not include any adjustment for ENWL's view of 'fixed costs', our sensitivity analysis with 'fixed costs' included shows that ENWL is still above our overall fast-track cost assessment benchmark."* The report goes on the say that this sensitivity analysis was undertaken '*on the basis of ENWL's view of 'fixed costs*''.

Ofgem's overall cost assessment results, adjusted for monetisation of cost of equity and outputs, suggested that our costs were £77m above Ofgem's benchmark (8 year value, 2012-13 prices, net distribution). KPMG's view of equivalent annual fixed cost uplift, as included in our July 2013 plan, is £10.7m per year ie £85m over eight years. We therefore do not understand how Ofgem has concluded that our costs are above its cost assessment benchmark when fixed costs are included.

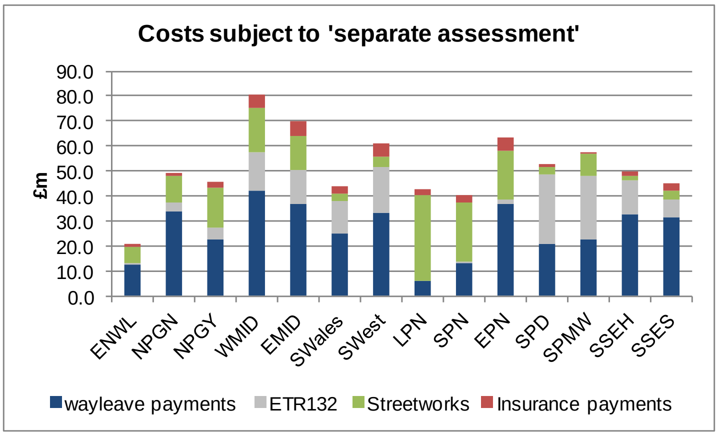
We have repeatedly asked Ofgem to share its sensitivity analysis to allow us to understand how it reached this conclusion, but it has not shared the analysis with us. Without being able to review Ofgem's analysis, we can only assume that Ofgem made an error in how it undertook its fixed cost sensitivity.

3.5 Normalisations and Exclusions

Ofgem made a number of normalisations and exclusions to its bottom up and totex analysis to adjust for company specific factors.

3.5.1 Costs Subject to Separate Assessment

Ofgem's cost assessment approach excluded some costs from analysis for 'separate assessment'. Our plan sought to continue to make efficiencies in all aspects of our expenditure. This included costs that have been excluded from modelling. The level of excluded costs forecast by different companies varies significantly, as shown in the following graph.



We accept that some of these excluded costs are legitimately incurred at different levels by different DNOs, but believe these should be subject to separate efficiency tests. These tests should give credit for efficient forecasts as well as penalising inefficiency. Where Ofgem did undertake separate assessment we are found to have efficient costs but are given no credit for this (our costs were just 72% of Ofgem view, or more than £43m lower). In other areas no separate efficiency assessment has been made.

3.5.2 Rail electrification costs

In their fast track plans, WPD companies included almost £100m of costs associated with rail electrification. Ofgem excluded these costs from its cost assessment for fast track companies. WPD has been allowed to charge these costs, in full, to customers. A mechanism has been included in the licence of WPD companies to allow these costs to be returned to customers if another party ultimately funds the work. However, we believe that that there are a number of credible situations where WPD can keep this allowance and it is therefore funded (subject to efficiency sharing factor) by WPD's customers. Examples of such potential situations are if

(a) some or all of the funded projects are cancelled
(b) some or all of the funded projects do not start
(c) the outturn costs are lower than forecast
(d) project phasing delays some costs into RIIO-ED2
(e) WPD delays billing for contributions into RIIO-ED2

Along with many other companies, we included provision for the associated NRSWA diversions within roads and bridges in our submission, but we made no provision for overhead line diversions, as we expect these be recharged to Network Rail. We are aware of at least six 132kV and four lower voltage overhead line diversions with an estimated capital cost of £1.75m but have assumed that these will be recharged.

This approach has artificially improved WPD's modelled performance in both bottom up and totex models, as well as artificially moving the upper quartile boundary against which all other companies are compared.

It is essential that these costs are included in WPD's cost base for slow track cost assessment for both bottom up and totex analysis. In the case of bottom up analysis this should be assessed as being unnecessary volume of work and disallowed. To do otherwise risks (a) inappropriately tough benchmarks for slow track companies and (b) inappropriate 'no worse' off adjustment for WPD for which it already has an outperformance opportunity built into its allowances.

4. Changes we have made in our new plan to improve our cost efficiency

In a small number of activities, we recognise that our plan was slightly more expensive than other DNOs' plans. Where this is the case we have made changes to our plan. We have removed more than £37m from our plan across seven activities where we accept that our July 2013 plan was slightly inefficient.

£m, gross costs, 2012-13 including associated RPEs	2016	2017	2018	2019	2020	2021	2022	2023	RIIO-ED1 total
Reinforcement	0.1	-0.9	-0.6	0.0	-1.7	-0.3	0.3	-2.2	**-5.2**
Asset Replacement	-1.1	-1.5	-1.3	-1.4	-1.4	-0.3	-0.3	-3.7	**-11.1**
Blackstart	-	-	-	-	-	-2.3	-2.3	-2.3	**-6.8**
Rising Mains & Laterals	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	**-1.7**
Occurrences Not Incentivised	-0.3	-0.3	-0.3	-0.3	-0.3	-0.4	-0.4	-0.4	**-2.8**
CEO Etc Costs	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	**-10.3**
Total	**-2.8**	**-4.1**	**-3.8**	**-3.3**	**-4.9**	**-4.7**	**-4.1**	**-10.1**	**-37.8**

Having understood from Ofgem its intention in normalising insurance costs out of its business support analysis we propose to slightly change the balance of insurance versus 'self insurance' (ie carrying risk and bearing the costs if the issue arises) in our plan. We have made this change in a way that has not changed the costs that we are proposing that customers pay. We have achieved this by moving these costs from Finance where many uninsured claims are reported.

Where it is clear that Ofgem did not fully understand our July 2013 plan, we have improved clarity of our justification. We have made considerable changes to the commentary document that supports our business plan data tables. We have also refined the presentation of our cost benefit analysis and condition based risk management approach for our resubmitted plan to make clearer where trade-offs exist that should be considered in qualitative adjustments. We have also included additional cost benefit analyses and scheme papers to assist Ofgem in understanding the make-up of our plan and how it is efficient.

We have made some other changes to our plan to reflect drivers other than efficiency, for example to reflect changes to Ofgem guidance or to update our plan for new information that was not available in July. A summary of all the changes that we have made to our plan can be found in our document 'Summary of Changes from the July 2013 Version of our Well Justified Business Plan'.

We firmly believe that these changes to our plan will lead to Ofgem assessing our plan as being well justified and within the upper quartile of all DNOs' plans.

5. How our new plan compares to Ofgem's view of efficient costs

We have undertaken substantial analysis to assure ourselves that our revised plan represents an efficient and well justified proposition for customers to fund.

The analysis overleaf compares Ofgem's analysis of our previous plan to the anticipated efficiency analysis of our revised plan.

It has clearly not been possible for us to pre-empt how changes to other DNOs' plans or wider changes to Ofgem's assessment approach may change the outcome of Ofgem's modelling. We have therefore based our analysis on DNOs' original 2013 plans.

Our analysis shows that we can expect our revised plan to be assessed to be upper quartile across all activity areas and to be comfortably within overall upper quartile, when assessed via a range of assessment tools that includes the small number of key changes set out in this annex.

We recognise that the upper quartile may change as a result of other companies' resubmitted plans. We are comfortable that we have sufficient headroom between our resubmitted plan and modelled upper quartile to allow for this.

Note that we have dropped our cost of equity assumption to 6.3% used by Ofgem in its fast track cost assessment and therefore we are confident our plan will also be assessed as efficient when combined with our financing costs.

Note that the variance between plans shown overleaf differs very slightly from that shown in our document 'Summary of Changes from the July 2013 Version of our Well Justified Business Plan' as Ofgem used a slightly later version (November 2013) of our plan for its cost assessment. We show variances here to that November version.

Analysis of how we expect the efficiency of our revised plan will be assessed by Ofgem

Ofgem's December 2013 assessment

£m, net, including RPEs	Bottom up						Totex		Combined assessment
	Network Investment	Network Operating Costs	Closely Associated Indirects	Business Support Indirects	Non Operational Capex	Total	Activity level drivers	High level drivers	
ENWL Plan	939	329	336	255	41	1900	1900	1900	1900
Ofgem assessment	784	375	416	199	64	1837	1935	1884	1855
Efficiency (compared to UQ)	120%	88%	81%	128%	64%	103%	98%	101%	102%

Anticipated assessed efficiency of our revised plan

£m, net, including RPEs	Bottom up						Totex		Combined assessment
	Network Investment	Network Operating Costs	Closely Associated Indirects	Business Support Indirects	Non Operational Capex	Total	Activity level drivers	High level drivers	
ENWL Revised Plan	925	336	336	245	41	1882	1882	1882	1882
Ofgem assessment - November 13	784	375	416	199	64	1837	1935	1884	1855
Changes due to linking errors and omissions in Ofgem assessment	20					20			15
Changes due to re-categorisation within and justified additions to our plan	17	2		8		27			20
Proposed changes to business support modelling to better reflect fixed costs and include insurance costs (here based on use of group based regression)				52		52			39
Amend asset replacement unit cost assessment to avoid aggregation of asset types	11					11			8
Qualitative adjustments that we expect Ofgem will make to the results of its models based on our submitted evidence	107	2				110			82
Assessment of excluded costs allowing credit for efficient forecasts		17	27			44			
Consider alternative totex modelling technique						0	155	115	34
Anticipated revised Ofgem assessment of our plan	939	396	443	259	64	2101	2089	1999	2087
Anticipated efficiency (compared to UQ)	98%	85%	76%	95%	64%	90%	90%	94%	90%

Change summary

£m, net, including RPEs	Bottom up						Totex	
	Network Investment	Network Operating Costs	Closely Associated Indirects	Business Support Indirects	Non Operational Capex	Total	Activity level drivers	High level drivers
Changes in ENWL plan	-15	7	0	-10	0	-18	-18	-18
Assumed changes in Ofgem assessment	155	21	27	60	0	263	155	115
Assumed change in efficiency assessment	-21%	-3%	-5%	-34%	0%	-14%	-8%	-7%

6. Conclusion

Ofgem's Fast Track analysis showed Electricity North West's business plan to be upper quartile based on its totex analysis but to be outside of the upper quartile in its bottom up assessment.

We have identified a number of significant issues with Ofgem's cost assessment approach used as part of its Fast Track decision. Several of the issues that we have identified are sufficiently material that correction of any one of them could have resulted in Ofgem reaching a different conclusion as to whether our plan was efficient and therefore sufficiently well justified. In combination, the issues that we have identified represent a very material distortion of Ofgem's view of the efficiency of our plan.

We conclude that Ofgem's totex models under-estimate the efficiency of our plan compared to other totex models.

We have identified a number of issues with Ofgem's bottom up analysis including the following very significant issues:

- asset replacement – the results of which are distorted by inappropriate assessment of required volumes due to 'cherry picking' and lack of qualitative adjustments, and inappropriate selection of 'expert view' unit costs
- business support - two assumptions in Ofgem's Business Support analysis materially distort the results of Ofgem's analysis: its incorrect treatment of fixed costs and its inappropriate exclusion of insurance costs
- refurbishment – which was based on very simple comparisons of DNOs' intervention rates and took no account of trade-offs due to differences in companies' asset management strategies

Ofgem's approach to exclusions and normalisations fails to recognise the efficient level of costs included in our plan for these excluded areas.

We believe that Ofgem made an error in how it undertook its fixed cost sensitivity.

We recommend that Ofgem makes a small number of important changes to its cost assessment approach for slow track companies to address these material issues.

We have reviewed our plan in great detail in preparation for resubmission and have undertaken substantial analysis to assure ourselves that our revised plan represents an efficient and well justified proposition for customers to fund. We have removed costs where new evidence suggests that the costs included in our July 2013 plan were inefficient. We have removed more than £37m of costs from our plan. Our analysis shows that we can expect our revised plan to be assessed to be upper quartile across all activity areas and to be comfortably within overall upper quartile, when assessed via a range of assessment tools that includes the small number of key changes set out in this annex.

We are confident that our resubmitted plan represents an efficient proposition for our customers in the North West to fund.

7. Appendices

The following documents are attached as appendices to this annex

Appendix 1 Cost analysis submitted in support of our July 2013 plan
Appendix 2 Oxera – ENWL's TOTEX efficiency in RIIO-ED1
Appendix 3 Oxera - Analysis of Business Support Costs
Appendix 4 Oxera - Business Support regression results
Appendix 5 Oxera - use of external databases to benchmark business support costs

[These appendices contain commercially sensitive information and have been redacted from public domain versions.]

ANNEX 15: THE POTENTIAL FOR FRONTIER SHIFT IN ELECTRICITY DISTRIBUTION

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Oxera

The potential for frontier shift in electricity distribution

Prepared for Electricity North West Limited

June 2013

Executive summary

In this report, Oxera examines the potential for electricity distribution network operators (DNOs) to improve their efficiency over the RIIO-ED1 period through ongoing efficiency improvements or frontier shift (ie, technological change or new working practices). Two approaches were used for this assessment:

– direct evidence—looking at what DNOs have achieved in terms of net frontier shift in the recent past (ie, the impact of technological change net of input price inflation);

– indirect evidence—looking at what other sectors have achieved in terms of frontier shift in the recent past before any impact of input price inflation is accounted for (the approach used by Ofgem in RIIO-T1 and RIIO-GD1).[1]

The assumption behind both approaches is that the past rate of technological progress is a good indicator of the potential future rate. In addition, the second approach assumes that the rate of technological progress in the benchmark sectors is a good indicator of the rate of technological progress in electricity distribution. Owing to the nature of these indirect comparisons, the robustness of this latter approach is likely to be significantly reduced relative to the former approach. However:

– the indirect comparisons are examined in this report in order to provide a cross-check;

– the direct evidence is currently preliminary as the data and models to be used for RIIO-ED1 have yet to be finalised.

Overall:

– the direct evidence shows a stable frontier (ie, no technological change net of input price inflation);

– the indirect total factor productivity evidence shows a frontier shift of around 0.4–1% per year, with a midpoint of 0.7% (before any impact of input price inflation is accounted for).

These two findings are likely to be broadly consistent—ie, suggesting a net frontier shift of around 0% per year—once input price inflation is overlaid on the latter. Similarly, ignoring the potential impact of real price effects (ie, input price inflation), the analysis indicates that it would be appropriate for a DNO to assume an overall efficiency frontier movement of around 0.7% per annum in its business plan.

[1] Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix. Consultation – appendix', July; and (2012) 'RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Final decision – appendix', December.

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1 Introduction

ENWL commissioned Oxera to examine the potential for electricity distribution companies to improve their efficiency through ongoing efficiency improvements or frontier shift (ie, technological change or new working practices). The basis for such an assessment was to examine:

– direct evidence—looking at what DNOs have achieved in terms of frontier shift in the recent past;

– indirect evidence—looking at evidence from other sectors (the approach used by Ofgem in RIIO-T1 and RIIO-GD1).[2]

1.1 Structure of report

The report is structured as follows:

– section 2 provides some background information on the two main methodologies used in the report;

– section 3 examines direct comparators, assessing the productivity potential of the electricity distribution industry;

– section 4 examines indirect comparators;

– section 5 concludes.

[2] Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix. Consultation – appendix', July; and (2012), 'RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Final decision – appendix', December.

2 Approaches to estimating the potential for frontier shift in electricity distribution

There are two elements to efficiency improvements:

– **catch-up**, or efficiency change, which includes all improvements in performance required to achieve best practice in an industry—ie, to catch up to the best-performing peers;

– **frontier shift**, or ongoing efficiency change, which relates to changes in the performance of best practice in the industry, through technological change or new working practices.

This report focuses on the latter element.

There are two main approaches to establishing a benchmark rate for the future potential for frontier shift in electricity distribution:

– **direct comparisons**—using data across DNOs and over time, it is possible to estimate the historical rate of frontier shift that DNOs have achieved. On the assumption that the past rate of technological progress is a good indicator of the potential future rate, this approach provides the most direct and relevant evidence for establishing a benchmark for the future potential for frontier shift in electricity distribution;

– **indirect comparisons**—based on data on other regulated companies or sectors in the economy, it is possible to estimate the historical rate of frontier shift that other regulated companies or sectors have achieved. On the assumption that the past rate of technological progress is a good indicator of the potential future rate *and* that the rate of technological progress in these sectors is a good indicator of the rate of technological progress in electricity distribution, this approach also provides useful evidence for establishing a benchmark for the future potential for frontier shift in electricity distribution.

These two approaches are discussed briefly below.

2.1 Direct comparators: frontier-based benchmarks

Frontier-based benchmarks involve analysing data on the DNOs over recent years, using techniques similar to those used to estimate relative efficiency across the DNOs. By modelling data across DNOs and over time, it is possible to estimate both the efficiency frontier and the rate of change in that frontier over the period examined. This historical rate of change in the efficiency frontier then provides a benchmark for the future potential for frontier shift in electricity distribution.

One of the key advantages of the direct comparators approach is that it relies on examining historical rates of change that have been achieved by the companies in the industry being considered. As such, conceptually, the only issue is whether one believes that the past rate of technological progress can continue in future.

This approach to identifying a rate of frontier shift has been used by regulators in instances where data across companies and over time has been examined.[3] The approach is examined further in section 3.

2.2 Indirect comparators: composite benchmarks

At a high level, UK regulators' ongoing efficiency targets tend to be based on a framework that has previously been used across a number of sectors, although its implementation varies. In summary, the framework reaches a conclusion on the potential for productivity improvement in the assessed industry through the use of indirect comparisons, such as estimates of (total factor) productivity (TFP) change achieved in whole sectors of the economy.[4]

The framework is made up of several components, and important decisions need to be taken for the assessment, including:

– the productivity measure(s) to be used. In this report TFP, as used by Ofgem, is examined;[5]

– the type and number of external comparators that will inform the benchmarks;

– the link between overall productivity improvement, frontier shift and catch-up to best practice;

– the period over which historical performance will be examined;

– the impact of growth on estimated productivity.

These are examined in section 4.

[3] See, for example, Nera (2008), 'The comparative efficiency of BT Openreach', a report to Ofcom, March; and (2005), 'The comparative efficiency of BT Openreach in 2003', a report to Ofcom, March.

[4] Such estimates are based on information from the National Accounts. See EU KLEMS Growth and Productivity Accounts, available at: http://www.euklems.net/index.html (accessed May 9th 2013).

[5] Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix. Consultation – appendix', July; and (2012), 'RIIO-T1/GD1: Real price effects and ongoing efficiency appendix. Final decision – appendix', December.

3 Direct evidence

3.1 Background

One of the main disadvantages of Ofgem's approach in RIIO-T1 and GD1 is that it relies on composite benchmarks from other sectors of the economy. Therefore, the companies in the comparator group do not undertake the same activities as the distribution and transmission companies, but are from sectors of the economy that are deemed by Ofgem to carry out similar activities. Owing to the nature of these indirect comparisons, the approach is likely to be less robust than evidence based on direct comparators (eg, what the electricity DNOs have achieved historically).

To address this issue, in this section Oxera examines the dataset that Frontier Economics used on behalf of Ofgem to assess the total expenditure (TOTEX) efficiency levels of the electricity DNOs.[6]

3.2 Approach

Frontier Economics' preferred model in Phase 1 of its work uses data over five years (2006/07–2010/11), with TOTEX as the cost measure, and number of customers, peak capacity, population density and national wage index as explanatory variables.[7] A time trend was included in its Phase 1 model to control for movement in costs over time, as a proxy to measure the technological change in the industry over the period. Based on the estimate for the time trend in the model, Frontier Economics argued that there has been an apparent technological regression of the industry. In Phase 2, Frontier Economics subsequently dropped the time trend owing to collinearity.[8] Both of these results would seem to indicate that little technological progress is possible in this sector.

However, there are some issues that need to be resolved when assessing the frontier shift:

– Frontier Economics' Phase 1 model included both the trend variable and the wage index with a view to capturing movement in costs over time. This results in an identification conflation issue, as acknowledged by Frontier Economics;[9]

– the time trend in the model captures the productivity change over the period, which also includes an estimate of efficiency change over the period.

To mitigate the first issue, Oxera modelled TOTEX in real terms (ie, deflating the TOTEX measure using the retail price index) prior to estimation and without the wage index in the model. When the wage index is excluded from the model specification, the trend variable provides an estimate of *net* ongoing efficiency (ie, ongoing efficiency *less* real price effects).

To mitigate the second issue, Oxera used stochastic frontier analysis to separately identify and estimate the frontier shift and efficiency change of the DNOs.

[6] ENWL provided the dataset to Oxera.

[7] The material used as the input to this report was limited to the presentation slides from Frontier Economics and the dataset used by Frontier Economics in its Phase 1 analysis. Both were provided to Oxera by ENWL.

[8] Frontier Economics (2013), 'Total cost benchmarking at RIIO-ED1 – Phase 2 report – Volume 1', June, p. 38.

[9] Ibid.

In addition, given that Frontier Economics has highlighted that there are inconsistencies in the first two years of the data, Oxera used year dummies to separate these data concerns from the actual technological shift.

Finally, it should be noted that the form of the models to be used for RIIO-ED1 has yet to be decided. For example, it could be considered that the modern equivalent asset value (MEAV) provides a more appropriate cost driver than those used in Frontier Economics' model, in that it captures, to an extent, the size and complexity of a DNO's asset base.[10] As such, two alternative models are used here: one based on Frontier Economics' model and one using MEAV.

3.3 Results from the direct evidence using DNO data

The *net* ongoing efficiency estimates using Frontier Economics' specification, and an alternative specification with MEAV as the scale driver, are presented in Table 3.1. Note that a negative value indicates an improvement—ie, costs are decreasing by the percentage value per annum.

Table 3.1 Direct evidence of potential *net* ongoing efficiency using Frontier Economics' data

	Frontier Economics' model (peak capacity, number of customers) (%)[1]	MEAV and population density (%)[1]	Is the *net* ongoing efficiency significantly differently from 0?[2]
How the *net* ongoing efficiency is estimated			
using time trend only	2.2	1.2	No
using year dummies and time trend	0	–2.4	No
If efficiency is assumed to be time-varying			
using time trend only	–0.3	0.2	No
using year dummies and time trend	–4.1	–3.7	No

Note: [1] The cost variable is TOTEX in constant prices. [2] At the 10% level of significance.
Source: Oxera analysis, using Frontier Economics data.

Hence, preliminary analysis indicates that, regardless of the model specification, the net ongoing efficiency achieved by DNOs in recent years does not appear to be statistically significant in the models, indicating that the technology (net of any input price inflationary effects) has been largely stationary.[11]

Since this is direct evidence on what the DNOs have actually achieved, it should be seen as being more robust in informing the future potential for net frontier shift, especially when the data has been further developed.[12]

[10] However, this measure has yet to be collated such that, within the current dataset, it is constant over time.

[11] This would need further examination when the data is more robust.

[12] As an alternative approach, Oxera normalised costs for wages as an approximation for removing the impact of real price effects (in so far as real price effects are captured by wages). Again, preliminary analysis indicates that, regardless of the model specification, the ongoing efficiency achieved by the DNOs in recent years does not appear to be statistically significant in the models. This would need further examination when the data is more robust—ie, by using a wage index that captures regional differences in wages rather than a national index.

3.4 Summary

The analysis undertaken in section 3.3 estimates the *net* ongoing efficiency achieved by DNOs over the period 2006/07–2010/11. That is, the figures in Table 3.1 are equivalent to Ofgem's 'net impact of RPE and ongoing productivity'.

Oxera's preliminary analysis indicates that the *net* ongoing efficiency achieved by the DNOs in recent years has not been statistically significant, indicating that the technology (net of any input price inflationary effects) has been largely constant.

While these findings would require further examination when the data is more robust, this is more direct and robust evidence on what has actually been achieved in recent years and, by implication, what is potentially achievable by the DNOs in future.[13]

[13] This direct measure assumes that historical performance is a good indicator of future performance, as does Ofgem's indirect approach.

4 Indirect comparisons: growth accounting-based TFP

4.1 Background to growth accounting and TFP

Growth accounting-based TFP is the method most widely used for measuring productivity growth in economic aggregates—eg, the whole economy or sectors of the economy. A major factor in the widespread adoption of TFP in this setting is that estimates can be (relatively) easily produced using country- or sector-specific National Accounts data, without having to rely on information from outside the country or the sector examined. Growth accounting, however, requires the adoption of a number of simplistic assumptions, most notably that markets are perfectly competitive, which could lead to unreliable estimates.

TFP analysis has often been used in a regulatory setting to derive an estimate of the performance improvements that are likely to be available in the future (usually until the next price control review). This analysis typically examines the productivity growth of a number of sectors of the *economy* that are deemed comparable to the assessed *companies*, referred to in this report as the 'comparator set'. The analysis uses this information to form a view on the potential for frontier shift, or 'ongoing efficiency' improvements, as Ofgem describes it. In essence, the comparator set forms the comparator group used to benchmark the regulated company.

4.2 Comparison of Oxera's approach and Ofgem's approach in RIIO-GD1

Based on this general framework (indirect TFP comparisons), this section provides Oxera's initial analysis of the scope for future productivity improvements. However, some adjustments have been made here to the framework adopted by Ofgem in RIIO-GD1:

– the final TFP estimate has been adjusted so that it reflects productivity improvements that are driven solely by ongoing improvements in best practice. The definition of frontier shift closely matches the definition of Ofgem's ongoing efficiency measure;[14]

– the analysis has been extended by constructing a 'composite' benchmark based on typical DNO activities. This can be used either as a cross-check or as the main source of productivity estimates.

In addition, slightly different choices relative to Ofgem's TFP analysis for RIIO-GD1 have been made, to reflect more closely the assessed industry and to strengthen the robustness of the final estimates.

– Oxera's comparator set includes industries that undertake activities similar to those undertaken in electricity distribution. Clearly, the selection of the comparator set requires a degree of judgement, and so ideally sensitivity analysis should be undertaken to check how the final estimates change with respect to the selection of the comparator set.

– The analysis focuses on a more recent timeframe. Ofgem examined productivity performance over a longer period, from 1970–2007, but there are issues with both the accuracy of the productivity estimates from the earlier periods and their relevance.

[14] Ofgem states that: 'The ongoing efficiency assumption is the expected productivity improvement that an efficient company should be able to make over the price control.' See Ofgem (2012), 'RIIO-GD1: Initial Proposals – Overview', July.

– The analysis examines only multi-factor productivity measures. Ofgem also looked at partial productivity indicators, but as these were constructed in a non-standard way, any conclusions drawn from them should be treated with caution.

4.3 Strengths and weaknesses of TFP analysis

The major advantage of TFP analysis of indirect comparators is that it can be implemented when there are no direct comparators, or when it is deemed that the data is not of sufficient quality to rely on direct comparisons. Although the TFP approach described above requires consistent data on inputs, outputs and their relative prices for the sectors of the economy that form the comparator set, this information is easily sourced from pan-European productivity databases (such as EU KLEMS) or national statistical agencies (such as the Office of National Statistics, ONS).

The main disadvantage of such analysis is that the comparator set is not made up of companies that undertake the same activities as the assessed company, but rather sectors of the economy that are deemed to carry out similar activities. Owing to the nature of these indirect comparisons, the robustness of this approach is likely to be significantly reduced relative to the frontier-based approaches discussed in section 2. Nevertheless, they are examined here since they can provide a cross-check on the results presented in section 2.

The other main disadvantage of TFP analysis is that the approach measures overall productivity growth, which includes elements of both catch-up efficiency and frontier shift. As such, it is unclear what proportion of productivity gains is attributable to each element. For this analysis, Oxera has used evidence from external sources to assess the possible composition of the estimated productivity measure (see section 4.2.4 for more details). Note that direct decomposition of the productivity estimate is possible when using direct comparisons (as in section 2) or where the TFP analysis uses frontier-based approaches.

4.4 Methodology

4.4.1 Productivity measures considered

For RIIO-GD1, Ofgem calculated productivity measures based on *two* available output measures: value-added (VA) and gross output (GO).[15] The choice of output measure on which to base the productivity estimates is very important because *VA-based TFP measures will always display larger productivity growth than GO-based TFP measures*,[16] and the differences can be quite significant. However, deciding which output measure is more appropriate is difficult and requires some judgement.

Both of these types of TFP measure are theoretically valid means of measuring productivity. The main advantage of using GO-based TFP measures is that gross output is the appropriate output concept since it includes the contribution of intermediate inputs to production. However, measuring GO at the aggregate level (as in EU KLEMS) is difficult and might lead to measurement errors.[17] As VA-based TFP measures are immune to these measurement issues, they are more robust to measurement error. The final decision on which TFP measure to rely on should be made according to whether these measurement issues are expected to have a material influence on the TFP estimates.

This issue cannot be addressed without further research; therefore, both measures are considered here.

[15] Ofgem (2012), 'RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix', July, sections 3 and 4.
[16] When the productivity analysis is based on growth accounting (the methodology adopted by both Ofgem and EU KLEMS).
[17] Further discussion on why this is the case is provided in Balk, B.M. (2009), 'On the relation between Gross Output- and Value Added-based productivity measures: The importance of the Domar Factor', *Macroeconomic Dynamics*, **13**, pp. 241–67.

Although GO-based TFP measures are not reported in the latest release by EU KLEMS, the primary data required for their estimation is available and has been used by Oxera to estimate GO-based TFP values for the selected comparator set.

4.4.2 Comparator sectors

During DPCR5 and RIIO-T1/GD1, Ofgem selected the following industries for its comparator set:

– Construction;
– Financial Intermediation;
– Manufacture of Chemicals & Chemical Products;
– Sale, Maintenance & Repair of Motor Vehicles/Motorcycles; Retail Sale of Fuel;
– Manufacture of Electrical & Optical Equipment;
– Manufacture of Transport Equipment;
– Transport & Storage.

Some of these sectors undertake activities similar to those undertaken by a typical DNO, but for others it is not clear why they have been included.

– Construction (F)—this appears to be an appropriate comparator since DNOs undertake a host of civic, electrical and mechanical engineering activities.

– Financial Intermediation (J)—this might be a useful comparator, although its applicability is limited since the financing activities undertaken by DNOs are likely to represent only a very small proportion of their total activities.

– Manufacture of Chemicals & Chemical Products (24)—this might be an appropriate comparator for gas distribution and transmission, but not for electricity distribution.

– Sale, Maintenance & Repair of Motor Vehicles/Motorcycles; Retail Sale of Fuel (50)—it is not clear why this sub-sector is an appropriate comparator. The sale of vehicles/ motorcycles and fuel is unlikely to be similar to activities undertaken by DNOs. It is also not clear how electricity distribution activities are similar to the maintenance and repair of motor vehicles/motorcycles.

– Manufacture of Electrical & Optical Equipment (30–33)—this is likely to be an appropriate comparator for electricity distribution, given that the industry undertakes a range of activities relating to the installation, operation and maintenance of assets that the ONS classes as 'Electrical & Optical Equipment'.

– Manufacture of Transport Equipment (34–35)—it is not clear why this would be a suitable comparator for electricity distribution.

– Transport & Storage (60–63)—this is likely to be an appropriate comparator for DNOs, especially the sub-sector of 'Inland Transport (60)'.

Other possible comparators from EU KLEMS include:

– Renting of Machinery and Equipment (71)—this appears relevant since leasing agreements are likely to be prevalent in the distribution and transmission sector.

– Computer and Related Activities (72)—this appears relevant due to the heavy adoption of automation in the electricity distribution and transmission sector.

– Other Business Activities (74)—this covers legal, technical, advertising and general administration activities, so it would probably be a good benchmark for distribution and transmission headquarter activities.

– Post and Telecommunications (64)—this may be relevant (but for a relatively small proportion of a DNO's cost base) owing to the adoption of IT and specialist communication systems for monitoring the distribution and transmission networks. Note, however, that the telecommunications sector has experienced rapid technological growth over the last 20 years, which translates to high productivity growth estimates. Indeed, according to EU KLEMS, this sector displays the highest productivity growth in the whole of the UK economy and might therefore not be a suitable comparator. As such, Oxera provides a sensitivity below (ie, with and without the sector), as well as presenting a weighted average based on the relevant proportion of the cost base.

As stated above, the selection of the comparator set is a decision based mostly on qualitative analysis and, as such, requires a degree of judgement. This mapping was, however, also discussed and confirmed with ENWL.

EU KLEMS does not include all the necessary information to derive TFP estimates for all lower-level aggregates, such as Computer and Related Activities (72). In such cases, the analysis presented here uses the TFP estimates of the higher-level aggregates that include the relevant sectors. Specifically, the final comparator set includes:

– Electrical and Optical Equipment;[18]
– Transport Equipment—using only a small set of DNO activities relating to 'Vehicles & Transport';
– Electricity, Gas and Water Supply;
– Construction;
– Transport and Storage;
– Post and Telecommunications—used mainly for the construction of the composite benchmark;
– Renting of Machinery and Equipment and Other Business Activities—this includes the relevant sub-sectors of Renting of Machinery and Equipment (71), Computer and Related Activities (72), and Post and Telecommunications (64).

4.4.3 Timeframe to consider

The timeframe over which productivity performance is measured in the comparator set is important for these types of indirect comparison, mainly because productivity tends to be influenced by the business cycle.[19] Compared with the long-run trend, TFP growth tends to be lower during recessionary periods (eg, since companies typically do not shed labour immediately, in order to maintain capacity at the expense of reductions in productivity) and higher during growth periods as this excess capacity is used. Thus, TFP growth comparisons are made over a complete business cycle to avoid misrepresenting the impact of recessionary or growth periods.

Examining UK VA output suggests the following potential business cycles over which TFP can be examined:[20]

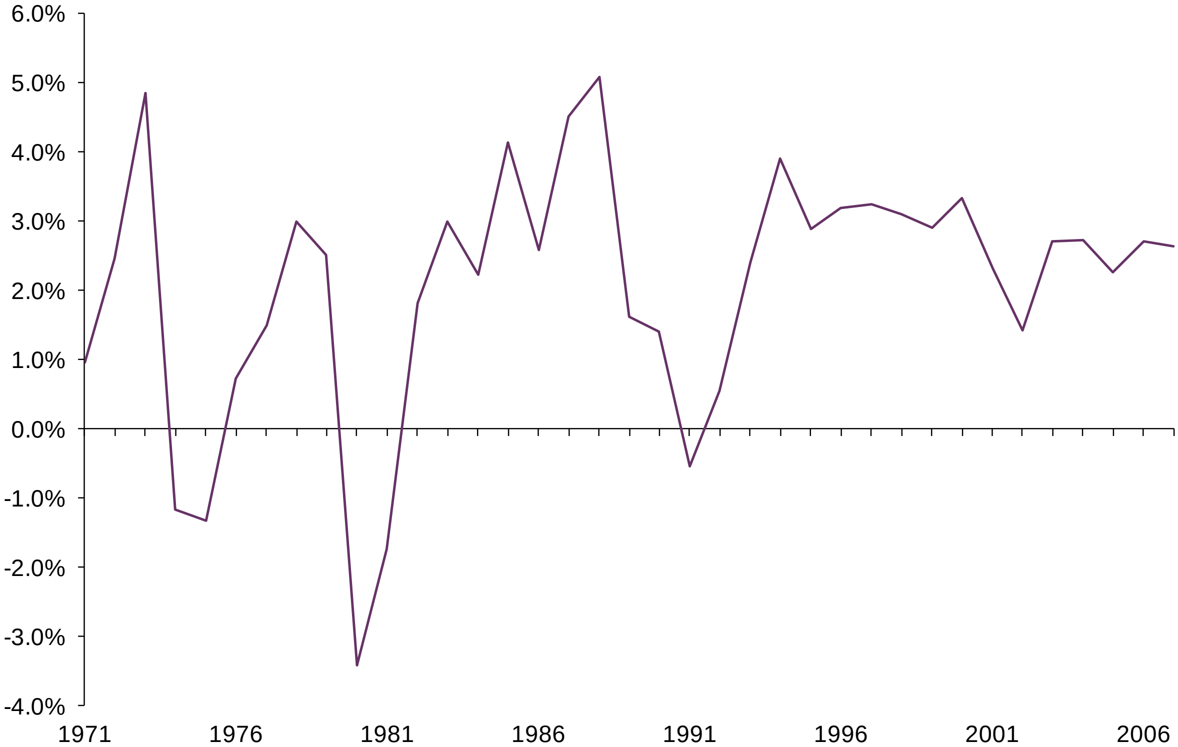
– there was significant volatility in the 1970–80 period—however, there is tentative evidence of two possible business cycles, one from 1970 to 1974 and a second from 1975 to 1981;
– one full business cycle from 1982 to 1991;
– a final business cycle from 1992 to 2008.

[18] Includes: Office, Accounting and Computing Machinery; Electrical Machinery and Apparatus; Radio, Television and Communication Equipment; Medical, Precision and Optical Instruments.

[19] Business cycles are periodic swings in an economy's pace of demand and production activity, characterised by alternating phases of growth and recession.

[20] The same business cycles can be seen when examining UK output expressed in GDP terms. See Bank of England (2010), 'The UK recession in context — what do three centuries of data tell us?', Quarterly Bulletin 2010 Q4, available at: http://www.bankofengland.co.uk/publications/Documents/quarterlybulletin/qb100403.pdf.

Figure 4.1 Annual change in VA, UK (whole economy)



Source: Oxera analysis based on EU KLEMS data.

4.4.4 Converting the TFP figure to an estimate of frontier shift

Ofgem's analysis of the potential for ongoing efficiency improvements relies on the use of productivity indicators, which include an element of efficiency change. This is described in the EU KLEMS methodology paper:[21]

> Under strict neo-classical assumptions, MFP [multifactor productivity] growth measures disembodied technological change. In practice, MFP is derived as a residual and includes a host of effects such as improvements in allocative and technical efficiency, changes in returns to scale and mark-ups as well as technological change proper. All these effects can be broadly summarized as 'improvements in efficiency', as they improve the productivity with which inputs are being used in the production process. In addition, being a residual measure MFP growth also includes measurement errors and the effects from unmeasured output and inputs.

As a reminder, the most common decomposition of productivity change in the academic literature is:

productivity change = efficiency change (catch-up) x technological change (frontier shift) x scale efficiency change

where:

- efficiency change measures how performance has changed from one period to the next, with reference to a peer set;
- frontier shift measures how best practice (optimal performance) has changed from one period to the next;
- scale efficiency change measures improvements in efficiency due to a company moving closer to the most productive scale size.

[21] Timmer, M., O'Mahony, M. and Van Ark, B. (2007), 'EU KLEMS Growth and Productivity Accounts: Overview', November, available at: http://www.euklems.net/data/overview_07ii.pdf (accessed July 10th 2009).

Ofgem assesses the potential for efficiency improvements (ie, catch-up) over the next price control period using a separate methodology and combines this with its estimate for ongoing efficiency improvements (or frontier shift). As such, the current analysis focuses on providing an estimate for the potential of the frontier shift of the electricity distribution industry only.

The issue is that the productivity measurement approach adopted by EU KLEMS (and, by extension, by Ofgem) does not allow the decomposition of the productivity estimate into its component parts. As such, to derive an estimate of frontier shift from the available TFP estimates, one has to rely on external evidence. The available studies that could be used for this purpose are few and all focus on assessing the productivity performance of whole economies, rather than industry sectors. Of these, the most notable is a study by Färe et al. (1994), which found that, on average, 75% of the economy-wide TFP growth, including the contribution from non-market sectors, was due to frontier shift. [22] This study was used in Oxera (2008),[23] and this particular split had previously been adopted by the Office of Rail Regulation and the Competition Commission.[24]

A more recent study by Giraleas (2009),[25] based on the EU KLEMS dataset, found that for the whole of the UK economy, the contribution of frontier shift to overall productivity change was approximately:

– 81–84% during the 1970–2007 period;
– 72–78% during the 1992–2007 period.

Given that the focus of the current analysis is 1992–2007 (see section 4.2.3), the latter estimate is the more relevant. The midpoint of this range (ie, 75%) is consistent with the estimate in Färe et al. (1994) and is therefore used below.

4.4.5 Additional issues

Additional issues to consider, if relevant, include:

– the effects of scale change on estimated productivity for the comparators;
– the impact of growth on estimated productivity.

Table 4.1 below summarises the per-year growth rate in terms of customer numbers, units distributed and peak demand.

Table 4.1 ENWL's actual and projected volume growth (% per year, by period)

Output measure	DPCR5	RIIO-ED1
Number of customers	0.1	0.1
Units distributed	–0.4	0.7
Network-wide peak demand	0.4	0.7

Source: ENWL.

The volume growth is relatively low and thus any adjustment to account for the impact of volume growth is likely to be small.

[22] Färe, R., Grosskopf, S., Norris, M. and Zhang, Z. (1994), 'Productivity Growth, Technical Progress, and Efficiency Change in Industrialized Countries', *The American Economic Review*, **84**:1, March, pp. 66–83—specifically, Table 4: Decomposition with scale effects, p. 78.
[23] Oxera (2008), 'What is Network Rail's likely scope for frontier shift in enhancement expenditure over CP4?', report prepared for the Office of Rail Regulation.
[24] Ibid., p. 25; and Competition Commission (2010), 'Bristol Water plc: A reference under section 12(3)(a) of the Water Industry Act 1991', Appendix K, para 51 (which refers to Oxera (2008), op. cit.), para 109 (which makes a net adjustment, implying at least a 10% adjustment for catch-up) and para 112.
[25] Giraleas, D. (2009), 'Productivity growth in the EU: Comparisons between growth accounting and frontier-based approaches', European Workshop on Efficiency and Productivity Analysis.

4.5 Results

Table 4.2 presents the average values of the yearly VA-based TFP change estimates for the comparator set, sourced directly from EU KLEMS.

Table 4.2 VA-based TFP estimates (% per year, by period)

Activity	Code	1970–74	1975–81	1982–91	1992–2007	1970–2007
Electrical and Optical Equipment	30t33	5.4	–1.4	6.4	**4.8**	4.1
Transport Equipment	34t35	–0.4	–0.6	6.0	**2.1**	2.3
Electricity, Gas and Water Supply	E	5.5	3.4	2.2	**0.8**	2.2
Construction	F	–3.3	–0.3	3.1	**0.7**	0.7
Transport and Storage	60t63	3.9	1.0	2.6	**1.9**	2.1
Post and Telecommunications	64	0.3	1.3	0.4	**5.6**	2.7
Renting of Machinery and Equipment and Other Business Activities	71t74	1.9	–2.6	–0.6	**0.7**	–0.2

Source: Oxera analysis, based on EU KLEMS.

As noted above, the TFP estimates from the early periods (ie, the 1970s) are of limited value for two main reasons. First, they are likely to be less accurate owing to both the lack of modern data-handling techniques available at the time, and the subsequent evolution of the National Accounting Standards, which govern how the primary data is collated. Second, there is the issue of relevance: how likely is it that productivity performance from the 1970s and 1980s can offer a reasonable guide for the potential of productivity growth some 30–40 years in the future?

The most relevant estimates are likely to come from the later period considered—ie, 1992–2007. TFP estimates from that period range between 5.6% and 0.7% per year, with an average of 2.4%. The high end of the range is from the Post and Telecommunications sector, which is to be expected, given the rapid technological growth of the IT industry. Although DNOs are highly likely to benefit from advances in IT in order to increase their productivity, their main activities involve larger-scale engineering projects and, as such, the impact of advances in IT is likely to be less pronounced. Excluding the Post and Telecommunications sector, the range of TFP change becomes 0.7–4.8% per year, with an average of 1.8%.

The Electrical and Optical Equipment sector has the second-largest TFP change estimate, which is also likely to be because of general advances in IT and electronics. This sector is also relevant to DNOs. Again, however, it is unlikely that they will be able to reap the full benefits from advances in manufacturing automation and miniaturisation, which appear to be some of the main sources of productivity growth in this sector. Excluding the Post and Telecommunications, and the Electrical and Optical Equipment sectors, the range of TFP change becomes 0.7–2.1% per year, with an average of 1.2%.

Table 4.3 presents the GO-based average values of the yearly TFP change estimates for the comparator set.[26]

[26] The primary data is from EU KLEMS, but the estimation has been undertaken by Oxera.

Table 4.3 GO-based TFP estimates (% per year, by period)

Activity	Code	1970–74	1975–81	1982–91	1992–2007	1970–2007
Electrical and Optical Equipment	30t33	2.0	–0.8	2.8	**1.8**	1.6
Transport Equipment	34t35	–0.4	–0.2	3.3	**0.6**	1.1
Electricity, Gas and Water supply	E	3.4	1.8	1.1	**0.2**	1.1
Construction	F	–1.5	–0.2	1.3	**0.2**	0.2
Transport and Storage	60t63	1.8	–1.2	1.6	**0.8**	0.7
Post and Telecommunications	64	0.2	2.0	0.1	**3.2**	1.8
Renting of Machinery and Equipment and Other Business Activities	71t74	–0.1	–3.7	–0.4	**0.4**	–0.6

Source: Oxera analysis, based on EU KLEMS.

The GO-based productivity estimates are significantly smaller than their VA-based counterparts: for the 1992–2007 period, the estimates now range from 0.2% to 3.2% per year, with a midpoint of 1%. Excluding Post and Telecommunications, the range becomes 1.8% to 0.2% per year, with a midpoint of 0.7%. Also excluding Electrical and Optical Equipment produces a range of 0.8% to 0.2% per year, with a midpoint of 0.5%.

Table 4.4 summarises all the above results.

Table 4.4 GO-based TFP estimates (% per year, by period)

	VA-based TFP		GO-based TFP	
	Range	Midpoint	Range	Midpoint
All sectors	5.6–0.7	**2.4**	3.2–0.2	**1.0**
Excluding Post and Telecommunications	4.8–0.7	**1.8**	1.8–0.2	**0.7**
Excluding Post and Telecommunications, and Electrical and Optical Equipment	2.1–0.7	**1.2**	0.8–0.2	**0.5**

Source: Oxera analysis, based on EU KLEMS.

To help narrow the range of the TFP estimates, a composite benchmark has been created based on the functions undertaken by DNOs. A number of different sectors were assigned to each function according to the similarity of the activities undertaken in these sectors relative to the different DNO functions. These functions were then given weights based on the TOTEX recorded for them in the 2010–13 period (which in turn was based on the TOTEX across all DNOs). For functions that were mapped to multiple sectors, the TFP performance of these sectors was given equal weight. The time period used to measure productivity change in the comparator set was 1992–2007. The mappings and relevant weights are presented in Table 4.5.

Table 4.5 Mapping of DNO functions to sectors of the economy

Activity	Weighting (%)	Comparators		
Load Related New Connections & Reinforcement	23	EGW	C	TS
Non-load Non-fault New & Replacement Assets	34	EGW	C	TS
Non-operational New Assets & Replacement	3	C	TS	
Faults	8	EGW	C	
Inspectns & Maint. (excl. Tree Cutting)	4	EGW		
Tree Cutting	4	C		
Network Policy (incl. R&D)	0	BA	EGW	EOQ
Network Design & Engineering	2	BA	EGW	EOQ
Project Management	2	BA	EGW	EOQ
Engineering Mgt & Clerical Support	6	BA	EGW	EOQ
Control Centre	1	BA	COMMS	
System Mapping - Cartographical	0	BA	COMMS	
Customer Call Centre (incl. compensation claims)	1	BA		
Stores & Procurement	1	TS		
Vehicles & Transport	2	TrE		
IT & Telecoms	3	COMMS		
Property Mgt	2	BA		
HR & Non-operational Training	1	BA		
Health & Safety & Operational Training	1	BA		
Finance & Regulation	2	BA		
CEO & Group Mgt/Legal & Co Secty/Community Awareness	1	BA		

Note: EGW, Electricity, Gas and Water Supply; C, Construction; TS, Transport and Storage; BA, Renting of Machinery and Equipment and Other Business Activities; EOQ, Electrical and Optical Equipment; COMMS, Post and Telecommunications; TrE, Transport Equipment.
Source: Oxera analysis, based on DPCR5 FBPQ submissions, provided by ENWL.

The productivity performance of this composite benchmark was found to be:

– 1.3% per year, using the VA-based TFP estimates;
– 0.5% per year, using the GO-based TFP estimates.

Given the above analysis, the potential for annual productivity improvement in the comparator set is likely to be between 1.3% and 0.5% per year.

Applying the 75%/25% frontier shift/catch-up split (as suggested by Färe et al. 1994 and Giraleas 2009), **the range for the potential frontier shift (before any impact of input price inflation is accounted for) becomes 1–0.4% per year, with a midpoint of 0.7%.**

4.6 Summary/conclusion

Given the issues discussed with regard to using TFP-based benchmarks to establish a possible range for the potential frontier shift, Oxera considers that such an approach can provide only a cross-check on the more direct measures (as undertaken in section 3), where these are available.

Based on TFP benchmarks, the range for the potential frontier shift is 1–0.4% per year. This is not directly comparable to technological progress in cost-efficiency terms (as estimated in section 3) as it excludes, among other things, the impact of real input price inflation. Once real input price inflation is included, it appears that the TFP-based benchmark is likely to be broadly consistent with a stable frontier.

5 Conclusions

In this report, the potential rate of future frontier shift, or ongoing efficiency change, has been estimated using two different approaches:

– **direct comparisons**—based on data across DNOs and over time, Oxera estimated the historical rate of net frontier shift that DNOs have achieved (ie, the impact of technological change net of input price inflation);

– **indirect comparisons**—based on data on other regulated companies or sectors in the economy, Oxera estimated the historical rate of frontier shift achieved by other sectors in the economy (before any impact of input price inflation is accounted for).

Both approaches assume that the past rate of technological progress can continue and is a good indicator of the potential future rate of technological progress. In addition, the indirect comparisons assume that the rate of technological progress in the comparator sectors is a good indicator of the rate of technological progress in electricity distribution.

Overall, the direct evidence shows a stable net frontier (ie, any technological progress is more or less equally offset by increases in input price inflation), while the indirect evidence shows a frontier shift of around 0.4–1% per year (excluding the impact of input price inflation).

Once input price inflation is overlaid on the indirect evidence, both approaches are broadly consistent. That is, both approaches suggest that a 0% net frontier shift could be a reasonable target for DNOs to achieve over the RIIO-ED1 period. Similarly, ignoring the potential impact of input price inflation, the analysis indicates that it would be appropriate for a DNO to assume an overall efficiency frontier movement of around 0.7% per annum in its business plan.

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Annex 16: Real Price Effects by EC Harris

Annex 16 and all associated appendices to Annex 16 have been redacted as they contain confidential information.

ANNEX 17: REVIEW OF RIIO-ED1 SUBMISSION BY PB POWER

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Review of Electricity North West Limited’s RIIO-ED1 Submission

Project no: 3513018A

Final

Review of Electricity North West Limited's RIIO-ED1 Submission

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Prepared for
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CONTENTS

ABBREVIATIONS

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CAPEX	Capital Expenditure
CB	Circuit Breaker
CBA	Cost Benefit Analysis
CBRM	Condition Based Replacement Model
CEPA	Cambridge Economic Policy Associates
CI	Customer Interruptions
CML	Customer Minutes Lost
CoP	Code of Practice
DPCR5	Distribution Price Control Review 5
DNO	Distribution Network Operator
ED1	Energy Distribution 1
EHV	Extra High Voltage
ENWL	Electricity North West Limited
ESQCR	Electricity, Safety, Quality and Continuity Regulations
GD1	Gas Distribution 1
GM	Ground Mounted
HV	High Voltage
ID	Indoor
LCT	Low Carbon Technology
LI	Load Index
LV	Low Voltage
MAMS	Master Asset Management Systems
MWh	Mega Watt Hour
NRSWA	New Road and Street Works Act
NPV	Net Present Value
KV	Kilovolts

OD	Outdoor
OFGEM	Office of Gas and Electricity Markets
OHL	Overhead Line
PSR	Priority Services Register
RAV	Regulatory Asset Value
RIIO	Revenue = Incentives + Innovation + Outputs
RIG	Regulations, Instructions and Guidance
RMU	Ring Main Unit
SOP	Suspension of Operational Practice
UG	Underground
WJBP	Well Justified Business Plan

1 INTRODUCTION AND RECOMMENDATIONS

Electricity North West Limited retained Parsons Brinckerhoff to undertake a review of its submission to Ofgem under the RIIO-ED1 price control review.

We reviewed various reports and spreadsheets which Electricity North West Limited has prepared in order to justify its proposed expenditure over the RIIO-ED1 price control period. The information we received was sometimes in draft form and we saw various iterations of plans as Electricity North West Limited finalised its proposals.

The aim of our review was fourfold:

- To assess the proposed volumes of assets and expenditure
- To review the substantiation of the investment case
- To examine the linkage between the proposed expenditure and outputs; and
- To review various Cost benefit Analyses related to specific expenditure programmes

The main body of this report review's Electricity North West Limited's programme of expenditure. In Section 2 we review the justification of increases in expenditure over the DPCR5 period (2010-15) and make a comparison of proposed volumes with those derived from independent modelling approaches we also review tha justification of overall scale of capex and balance between programmes. In Section 3 we review the linkages between the proposed expenditre and outputs. The Annex contains Parsons Brinckerhoff's review of Electricty North West Limited's presentation of its expenditure programme. In the Annex we test any claimed links to stakeholder inputs, review the substantiation of the business case and review Cost Benefit Analyses for various investment proposals.

1.1 Recommendations

Our recommendations are included in the bulk of our report, however, for ease of reference we have amalgamated them below:

Justification of increases over the DPCR5 period (2010-15)

We recommend that the Well Justified Business Plan clearly outlines the drivers for expenditure.

Justification of overall scale of capex and balance between programmes

Our recommendations are:

- Complete the reinforcement commentary
- Explain the benefits of the Future Headroom Capacity model
- Explain how the Transform model is customised
- State more clearly which forecast has been used as the basis for investment figures
- Explain why there is zero expenditure forecast for BT21CN
- Explain further any policy on refurbishment versus replacement (or reinforcement versus replacement)

2 ASSESSMENT OF PROPOSED VOLUMES

2.1 Justification of increases over the DPCR5 period (2010-15)

In its submission to Ofgem, Electricity North West Limited will submit proposed expenditure levels based on different volumes of assets to be replaced, acquired or refurbished across a range of asset categories during RIIO-ED1.

This review looks at volume increases in assets during the current regulatory period – DPCR5. We have analysed, where possible, Electricity North West Limited's rationale for volume increases during the current regulatory period. We believe that our review will be useful in justifying the merits of future volumes of assets.

Electricity North West Limited has proposed volumes and calculated costs for asset types across a diverse range of asset categories. For some of these categories the anticipated interventions during RIIO-ED1 will be higher than what is currently undertaken in the DPCR5 period. A majority of these increases originate from an ageing population of assets and the need to embark on network improvement activities geared towards network resilience, reliability, availability, safety and high network performance[1].

A summary of annual average increases in expenditure for the on-going DPCR5 and projected RIIO-ED1 periods is illustrated in the table below.

[1] *Our Track Record: Delivering investment for customers; WJBP V4 Narrative Document; Section 2.2; page 18*

Annual Average Increases in Expenditure					
Price Control Connection Projects	DPCR5: 5 Year Period 2010 – 2015	RIIO-ED1: 8 Year Period 2016 – 2023	On-going Period	RIIO-ED1 Period	Percentage Increases
	(£m)	(£m)	Average Annual Spend (£m)		%
Legal & Safety	13.9	41.4	2.8	5.2	85%
Asset Replacement	243.2	405.9	48.6	50.7	4%
Refurbishment	44.5	112.1	8.9	14.0	57%
Civil Works	26.4	79.2	5.3	9.9	87%
ESQCR	29.3	0.0	5.9	0.0	-100%
Flooding	7.9	10.3	1.6	1.3	-20%
Other Resilience	0.0	17.3	0.0	2.2	n/a
Reinforcement	84.0	115.6	16.8	14.4	-14%
Diversions	18.2	28.3	3.6	3.5	-2%
Undergrounding	6.1	9.0	1.2	1.1	-6%
Environmental	3.1	6.7	0.6	0.8	40%
Quality of Supply	30.0	0.0	6.0	0.0	-100%
Worst-served customers	2.2	3.4	0.4	0.4	-3%
Losses	0.0	10.0	0.0	1.3	n/a
Total	**508.8**	**839.2**	**101.8**	**104.9**	**3%**

Source: Electricity North West Limited WJBP v4

Annual average expenditure for the 14 categories of network investment programmes in RIIO-ED1 is 3 percent higher than that for DPCR5. Expenditure on Asset Replacement, Refurbishment and Reinforcement programmes accounts for around 48 percent of the total investment spend over the RIIO ED1 period.

Electricity North West Limited has also prepared a network investment summary[2] with associated gross costs for core, non-core and stand alone funding price controlled activities for both DPCR5 and RIIO-ED1 period. This is summarised in the table below.

[2] *C10: Summary – Network Investment by Category ENWL_RIIO_ED1_Network_Investment_10 June 2013;Table C10-NI Summary*

Summary of Network Investment by Category of Connection Projects for DPCR5 and RIIO-ED1																	
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	DPCR5	RIIO-ED1	Increases
Connection projects	Within Price Control	DPCR5 (£m)					RIIO-ED1 (£m)								(£m)	(£m)	%
Core	Diversions	4.01	4.47	5.23	2.32	2.15	3.49	3.55	3.21	5.21	3.20	3.20	3.20	3.20	18.2	28.3	56%
Core	Reinforcement – General	5.07	10.48	15.96	25.64	24.99	10.62	14.69	8.74	10.63	11.89	9.09	16.71	16.28	82.1	98.7	20%
Core	Reinforcement - DSM Payments to avoid Reinforcement	0.05	-	-	0.05	0.15	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.3	2.0	699%
Core	Fault Level Reinforcement	0.54	0.45	0.48	0.21	0.94	0.73	1.48	1.16	1.73	2.10	4.26	2.71	0.73	2.6	14.9	470%
Core	ESQCR	4.19	5.42	5.73	6.68	7.25	-	-	-	-	-	-	-	-	29.3	-	-100%
Core	**Asset Replacement**	**34.25**	**47.23**	**55.45**	**56.61**	**46.64**	**48.69**	**42.48**	**49.50**	**43.30**	**53.83**	**49.78**	**50.52**	**50.91**	**243.2**	**389.0**	**62%**
Core	**Refurbishment**	**7.33**	**11.94**	**7.28**	**7.37**	**10.54**	**13.95**	**14.44**	**13.68**	**14.17**	**13.69**	**14.18**	**13.69**	**14.25**	**44.5**	**112.1**	**152%**
Core	**Civil Works**	**4.46**	**5.67**	**5.27**	**5.12**	**5.84**	**9.92**	**9.92**	**9.92**	**9.92**	**9.92**	**9.92**	**9.92**	**9.75**	**26.4**	**79.2**	**200%**
Core	Operational IT & Telecoms																0%
Core	Legal and Safety	1.69	2.98	3.38	3.11	2.74	5.51	5.34	5.19	5.10	5.07	5.07	5.07	5.10	13.9	41.4	198%
Core	QoS	2.59	7.06	5.48	8.19	6.70	-	-	-	-	-	-	-	-	30.0	-	-100%
Core	High Value Projects (ex ante)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
Core	High Value Projects (re-openers)						-	0.46	70.03	75.14	32.71	10.65	8.80	9.65	-	207.4	-100%

Non Core	Flooding	3.49	2.29	1.68	0.41	0.03	2.39	2.36	2.34	2.30	0.86	-	-	-	7.9	10.3	30%
Non Core	BT21CN	3.26	5.53	8.43	5.00	0.50	-	-	-	-	-	-	-	-	22.7	-	100%
Non Core	Technical losses						2.50	2.50	2.50	2.50	-	-	-	-	-	10.0	30%
Non Core	Environmental	0.13	0.94	1.11	0.49	0.40	0.88	0.88	0.88	0.88	0.88	0.88	0.70	0.70	3.1	6.7	-100%
Non Core	High Impact Low Probability (HILP)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0%
Non Core	CNI	-	-	-	-	-	2.60	-	-	-	-	-	-	-	-	2.6	100%
Non Core	Black Start	-	-	-	-	-	-	-	-	-	-	4.89	4.89	4.92	-	14.7	100%
Non Core	Rising mains and laterals	-	-	0.45	0.93	1.65	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	3.0	16.9	456%
Stand Alone Funding (RAV)	Undergrounding Within/ Outside designated areas	0.24	1.19	1.33	1.87	1.47	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	6.1	9.0	47%
Stand Alone Funding (RAV)	Worst Served Customers	-	-	0.32	1.05	0.84	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	2.2	3.4	52%
Total		**71.3**	**105.7**	**117.6**	**125.0**	**112.8**	**105.2**	**102.0**	**171.1**	**174.8**	**138.1**	**115.8**	**120.1**	**119.4**	**532.4**	**1,046.5**	**97%**

Source: Electricity North West Limited;C10 - Network Investment Summary; ENWL_RIIO-ED1_Network_Investment_10Jun2013

During DPCR5 Asset Replacement, Refurbishment, Civil Works and Diversions represent the categories which represent the greatest levels of investment. Parsons Brinckerhoff's review of the justification of expenditure increases over DPCR5 has focused on these project categories:

2.1.1 Asset Replacement Projects

Electricity North West Limited uses a Condition-Based Replacement Model (CBRM) process which involves analysis of detailed asset registry condition data in order to generate Health Index (HI) scores. The HI scores act as 'triggers' which may lead to expenditure on replacing assets.

We have selected asset types for which expenditure on replacement programmes has increased between 2010 and 2015. The programmes below are listed in order of magnitude of expenditure and account for 47 percent of the total direct costs for the DPCR5 period. (Source ENWL_RIIO_ED1_Network Investment 10June2013 spreadsheet, tab CV3 asset replacement).

These asset types are:

- 33KV Underground Cable (Non Pressurised)
- 132KV Transformer
- 6.6/11kV Underground Cables
- 6.6/11kV Poles
- 132kV Underground Cable (Non Pressurised)
- 132kV Circuit Breaker (Gas Insulated Busbars)

2.1.1.1 33KV Underground Cable (Non Pressurised)

We have appraised projects such as the replacement of oil-filled 33kV underground cables targeted at improved network performance and reduced fault levels, ESQCR, reliability and availability on the 33kV network circuits. Our observation is that Electricity North West Limited's intention to introduce higher resilience and safeguards to the network justify the increase in volumes and costs. These increases are also driven by public safety, environmental performance and customer satisfaction in the form of reduced CIs and CMLs.

We expect the expenditure of £28 million which represents approximately 12 percent of the overall spend over DPCR5 to be justified by these drivers.

2.1.1.2 132kV Transformer

The need to size up the primary network with transformers of sufficient capacity to meet varying but incremental peak demands on the system is imperative and necessary to maintain acceptable Load Index (LI) levels, especially as network operations transition to a low carbon economy. Electricity North West Limited has implemented a mix of replacement and refurbishment projects as intervention schemes for this asset category. These have introduced cost saving measures through least and we view these as very commendable. These projects account for 11 percent of the overall total direct costs for asset replacement schemes between 2010 and 2015.

We view the £19 million investment in these areas as being driven by customers and increased inflation in manufacturing. These two drivers are considered as significant justifications for increases in DPCR5, as is observed with the 33kV underground cables. We also believe that the reference to existing competitive tendered rates and empirical data used for the determination of unit costs in DPCR5 serves as additional justification for increases in expenditure.

2.1.1.3 6.6/11kV Underground Cable

Our observations here are similar to those we made for 33kV underground non-pressurised cables. A total of 154 kilometres of 6.6/11kV underground cables were earmarked for replacement at a total cost of £19 million, which represents approximately 8 percent of the total direct costs for the 2011-2015 period. Despite the 32 percent increase in expenditure forecast for RIIO-ED1, we consider the replacement strategy adopted for this asset as necessary for the establishment of a reliable network capable of meeting customer expectations.

2.1.1.4 6.6/11kV Poles

A population of 7,779 overhead poles for 6.6/11kV circuits has been identified for replacement at a cost of £14 million over DPCR5. Electricity North West Limited has stated that the degree of deterioration of these assets requires the replacement of poles in order to maintain a continuity of supply to customers on the secondary network. This quality of supply need appears to justify the increases in volumes over the period. The RIIO-EDI investment plan adopts the on-going strategy of continuous replacement of these poles but at a reduced cost of £2 million.

We therefore accept that reliability, availability and regulatory compliance to the security of supply are drivers which justify these increases. We believe these will most likely be scrutinised by Ofgem.

2.1.1.5 132kV Underground Cable (Non-Pressurised)

The same principle that holds for the replacement of 33KV underground cables has been adopted for the replacement of this asset type. £13 million was allocated over DPCR5 for the delivery of 40 kilometres of 132kV non-pressurised underground cables. This represents 5 percent of the total capital expenditure for the programme. The potential for a protracted disconnection of customer supplies due to faults and the loss of multiple circuits at potential pinch points is severe. This largely justifies the need for investment in the area of remedial works on underground cables along the 132KV circuits and the costs allocated to mitigate risks that could emerge in identified areas with the potential for such events.

The programme is an on-going scheme and we note the reduction in the number of interventions forecast over the RIIO-ED1 period.

2.1.1.6 132kV CB (Gas Insulated Busbars) (ID) (GM)

The ability of switchgear to effectively isolate a fault without compromising the safety of the public or field personnel, or the security of the network, is crucial to the operation of a reliable and safe network. Further to the approval and adoption of free standing GIS outdoor switchgears, Electricity North West Limited embarked on the replacement of 132kV air insulated switchgears with circuit breakers installed with gas insulation busbars. We note that this is part of an on-going attempt to identify switchgear assets and components approaching end-of-life and to specify appropriate intervention strategies intended to improve safety expectations. We believe that this justifies the increases in volumes and costs over the current period.

2.1.2 Refurbishments

At a total cost of £44.5 million, refurbishment programmes constitute around 9 percent of costs allocated to projects between 2010 and 2015. This cost allocation is for the delivery of remedial activities for various asset types across all voltage levels of the primary and secondary networks of the Electricity North West Limited distribution system.

We understand that, similar to strategies implemented for asset replacement programmes, Electricity North West Limited has identified volumes based on a CBRM process. This establishes the health of assets and recommends fit-for-purpose interventions to minimise the probability of the failure of the assets and to avoid the financial and reputational consequence of such failures.

We examined three refurbishment programmes with the largest increases in expenditure over the DPCR5 period: (Source ENWL_RIIO_ED1_Network Investment 10June2013 spreadsheet, tab CV5 Refurbishment)

- Refurbishment – 6.6/11kV Poles
- Refurbishment – 132kV Tower Foundation
- Refurbishment – LV Poles

These activities constitute 62 percent of the overall refurbishment connection projects for the DPCR5 period. The largest refurbishment programmes during DPCR5 are given in the following table:

Refurbishment Programmes in Order of Magnitude of Expenditure for DPCR5							
Refurbishment Programme				Volumes		Total Direct Costs	
Asset category	Activity	Voltage	Units	DPCR5	RIIO-ED1	DPCR5 (£m)	RIIO-ED1 (£m)
6.6/11 kV Poles	Refurbishment - Poles	HV	#	25,495	28,207	16	13
132kV Tower	Refurbishment - Tower Foundation	132kV	#	-	-	8	-
LV Poles	Refurbishment - Poles	LV	#	13,448	11,721	4	5

Source: Electricity North West Limited; CV5 – Refurbishment Investment Plan: ENWL_RIIO-ED1_Network_Investment_10June2013

2.1.2.1 6.6/11KV Poles

Electricity North West Limited, in its Business Plan Commentary, gives a combination of replacement and refurbishment projects that will deliver the management of secondary network overhead lines. As stated in the previous sections, we understand that the decision to mix and match asset management programmes is intended to reduce project costs and hence the use of least cost options of remedial interventions for deteriorated pole assets.

Our understanding is that these volumes come from identified assets with higher frequency inspection regimes, hence resulting in higher intervention and maintenance works. We note that 22,495 poles were identified to undergo intervention activities, at a total cost of £16 million, over DPCR5 account for 25 percent of the total spend for refurbishment programmes.

We believe that increased volumes are justified on the grounds of legal compliance, overall public safety, acceptable whole-life asset performance and customer satisfaction. Equally, we believe the scheme, which is expected to increase in direct cost over RIIO-ED1 by 50 percent, reinforces Electricity North West Limited’s commitments to reducing costs associated to entire pole replacements.

2.1.2.2 132KV Tower Foundation

Remedial works for 132kV steel tower foundations can be a complicated exercise. As such, survey exercises undertaken by Electricity North West Limited (to identify and collect accurate condition data representing information on levels of dilapidation) are of importance to the understanding of the scale and type of intervention necessary to restore the assets to acceptable structural standards.

We understand that, although the need to reduce intervention based costs is crucial, the safety of the public should not be undermined and tower refurbishment works defined by Ofgem Regulations, Instructions and Guidance (RIG) will come at a cost. Issues such as tower location and the degree of tower foundation dilapidation need to be considered before accurate interventions can be prescribed. Such considerations demonstrate that risk mitigation measures have been taken to ensure safety. We consider increases aimed at ensuring public safety a very important justification for the remedial works.

The total direct cost of £8 million, which represents 18 percent of the total spend on refurbishment works over DPCR5, can be justified by the need to ensure public safety and the requirement to maintain security of supply in the event of a failure of the tower foundation.

2.1.2.3 LV Poles

Observations made for remedial works planned on LV poles are similar to those stated for the 6.6/11kV pole asset types. The activities specified to restore LV poles to fit-for-purpose condition is understood to be part of a combination of refurbishment and replacement projects aimed at extending the asset life and reducing costs. We note that these volumes come from poles identified with condition data captured during frequent and up-to-date plant inspections and surveys backed up with photographic evidence suggesting the criticality level of plant deterioration thus leading to increased levels of intervention and maintenance works.

Once again, we consider the drive to reduce costs by refurbishing ,more poles over DPCR5 justifies the £4million spend and the increases in volume during this period

2.1.2.4 Civil Works

Electricity North West Limited recognises that these are the assets (including substation plinths, buildings, tunnels, bridges and compounds) most visible to the general public. Hence, volumes have been identified, and remedial works prioritised, following elaborate asset inspections and conditioning processes where weighted HI scores were used to determine levels of deterioration. As such, we agree with Electricity North West Limited that projects that need to keep these structures in good condition are mandatory.

Electricity North West Limited has invested £26.4 million over DPCR5 to ensure that all civil structures meet statutory safety standards. We agree with Electricity North West Limited's suggestion that these investments are driven by the need to intervene in restoring dilapidated civil items and replace component assets (like doors, roofs, earth rods and bars, and plinths) within and around the structures. These two drivers justify the increases we have identified for a majority of the secondary indoor 6.6/11kV substations. We would, however, recommend that this case be clearly stated in the business proposal. The intention to increase activities in RIIO-ED1 should be equally underpinned by emphasising the same case of safe buildings and good neighbourhood assurance.

The entire programme represents approximately 5 percent of the entire network investment expenditure for the period between 2010 and 2015.

2.1.3 Diversions (Non-Rechargeable)

Our review shows that projects under this investment plan are categorised into 3 separate schemes. These are:

- Injurious Affection Claims
- Highway Diversions (NRSWA)
- Wayleave Terminations

Expenditure on non-rechargeable Diversionary projects is given in the following table:

Summary of Non-Rechargeable Diversionary Projects				
Programme Category			Total Direct Costs	
Diversions (non-fully rechargeable)	Voltage	Units	DPCR5 (£m)	RIIO-ED1 (£m)
Conversion of wayleaves to easements, easements, injurious affection	LV	Claims settled	-	-
Conversion of wayleaves to easements, easements, injurious affection	HV	Claims settled	0.13	0.28
Conversion of wayleaves to easements, easements, injurious affection	EHV	Claims settled	0.34	1.09
Conversion of wayleaves to easements, easements, injurious affection	132kV	Claims settled	7.11	9.91
Conversion of wayleaves to easements, easements, injurious affection	**Sub-Total**		**7.58**	**11.28**
Diversions due to wayleave terminations	LV	Diversions completed	1.74	2.84
Diversions due to wayleave terminations	HV	Diversions completed	2.93	5.46
Diversions due to wayleave terminations	EHV	Diversions completed	1.08	2.06
Diversions due to wayleave terminations	132kV	Diversions completed	0.00	2.00
Diversions due to wayleave terminations	**Sub-Total**		**5.75**	**12.36**
Diversions for highways (funded as detailed in NRSWA)	LV	Diversions completed	-	-
Diversions for highways (funded as detailed in NRSWA)	HV	Diversions completed	2.29	2.82
Diversions for highways (funded as detailed in NRSWA)	EHV	Diversions completed	2.57	1.82
Diversions for highways (funded as detailed in NRSWA)	132kV	Diversions completed	-	-
Diversions for highways (funded as detailed in NRSWA)	**Sub-Total**		**4.86**	**4.64**
Total			**18.18**	**28.28**

- *Source: Electricity North West Limited ED1 BPDT Final Investment Plan*

The cost of executing these projects is £18.2 million which represents 3.6 percent of the entire investment expenditure during DPCR5. It is expected to increase to £28.3 million over the RIIO-ED1 period, indicating an increase of approximately 55 percent rise in direct costs.

2.1.3.1 Injurious Affection Claim

The combined increase in volumes of diversion projects related to “conversions of way leaves to easements, easements and injurious affection claims” comes under the Electricity North West Limited diversion programme. Over DPCR5, approximately £7.6 million was earmarked to deliver projects in this category. Over this period there has been approximately 130 claims per annum resulting from perceived injurious affection of overhead circuits, particularly at 33kV and 132KV levels, over the last 3 years. We understand from the commentaries provided that these claims have risen as a result of Compensation agents inciting claims and an increase in diversionary works where opportunities to do so abound. We note that compensation payments vary in size but the increase in the number of claims put forward to Electricity North West Limited justifies the increase in volumes of projects and costs. We also view the increase in costs as an off-shoot of uncertainties surrounding unplanned costs and the magnitude of compensation claims made over this period.

2.1.3.2 Highway Diversions

The need to divert overhead cables along routes of major construction projects and in compliance to New Road and Street Works Act of 1991 underpins increases in this area. This category of projects accounts for 27 percent of the costs for diversionary works between 2010 and 2015. Increases in this area are the result of delivering projects that improve diverted electricity assets on the public highway and are driven by public sector infrastructure projects.

We assume that uncertainty surrounding size of infrastructure projects embarked on by developers and limitations to alternative cable and plant routes which could be adopted may in actual sense have contributed to increases in volume and intervention costs over this period. It also justifies why Electricity North West Limited envisages an approximate 115 percent increase in expenditure for projects in this category in RIIO-ED1, particularly in light of speculative 132kV overhead diversionary works stemming off from the proposed construction of the 3.6GW Nuclear power station at Cumbria

2.1.3.3 Wayleave Terminations

Electricity North West Limited has stated that termination of wayleaves typically come from requests made by developers to facilitate constructions work. Our observations for this category of diversion projects is quite similar to those highlighted in the injurious affection claims sections. The need to respond to requests for diversion of assets where Electricity North West Limited had not secured easements justifies the associated increases costs especially over the last three years.

We identify this programme as fundamentally customer driven.

2.2 Comparison of proposed volumes with those derived from independent modelling approaches

Parsons Brinckerhoff's 2012 report, "Review of RIIO-ED1 Submission for Electricity North West Limited", included an analysis of proposed volumes in RIIO-ED1 for a selected number of identified asset types. This analysis tested and evaluated Electricity North West Limited's justifications for expenditure and covered both CBRM and non-CBRM processes. The tests were run through a proprietary ageing model which served the purpose of a broad measure cross check of the results of the CBRM modelling.

Some of the assets tested were as follows:

- 6.6/11kV CB (GM) Primary (CBRM)
- 33kV Transformer (GM) (CBRM)
- 132kV CB (Air Insulated Outdoor) (CBRM)
- 6.6/11kV UG Cable
- 6.6kV RMU (CBRM)
- 132kV Transformer (CBRM)
- 6.6/11kV Switch (CBRM)
- LV Board (WM) (CBRM)
- 6.6/11kV Poles
- LV Poles

We have now reviewed Electricity North West Limited's revised investment plan for RIIO-ED1. Since our initial report, significant changes have been made to the investment plan and there has therefore been a shift in the hierarchy of assets in terms of proposed expenditure per replacement programme. The table below reflects Electricity North West Limited's revised investment plan for asset replacement programmes. These assets are listed in order of scale of expenditure in RIIO-ED1. However, only assets for which we had originally developed comments and recommendations in our last report will be considered in the following sections.

Overall, the 16 listed asset types above account for over 80 per cent of the total direct costs of the £389 million earmarked for replacement programmes in RIIO-ED1.

Proposed Volume Increases over DPCR5 into RIIO-ED1 for Asset Replacement Programme																		
Programme Category			DPCR5 Period					RIIO- ED1 Period								Volumes		
Asset Type	Asset Type	Voltage	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	DPCR5 (#)	RIIO-ED1 (#)	Increases (%)
33kV Transformer (GM)	EHV	Each	4	7	4	5	8	4	8	8	11	12	15	16	13	28	87	211%
6.6/11kV CB (GM) Primary	HV	Each	47	63	28	51	60	94	117	111	105	101	122	131	85	249	866	248%
33kV UG Cable (Non Pressurised)	EHV	Km	14	6	7	24	22	12	15	12	15	12	15	12	15	73	108	48%
132kV CB (Gas Insulated Busbars)(ID) (GM)	132kV	Each	-	-	-	-	2	9	-	10	1	8	-	-	7	2	35	1650%
6.6/11kV RMU	HV	Each	123	182	229	214	155	320	319	312	312	312	312	312	312	903	2,513	178%
6.6/11kV UG Cable	HV	Km	13	23	49	35	35	31	31	30	30	30	30	30	30	154	244	58%
6.6/11kV Transformer (GM)	HV	Each	158	139	134	190	125	90	90	90	90	263	263	263	263	746	1,412	89%
LV Main (UG Plastic)	LV	Km	30	19	20	13	13	25	25	25	25	25	25	25	25	94	200	113%
132kV Transformer	132kV	Each	-	2	3	2	12	2	1	1	2	3	2	4	2	19	17	-11%
132kV Tower	132kV	Each	13	22	35	70	7	25	25	25	25	25	25	25	25	147	200	36%
6.6/11kV Switch (GM)	HV	Each	21	41	87	131	112	317	317	317	317	317	317	317	317	392	2,536	547%
132kV UG Cable (Non Pressurised)	132kV	Km	1	7	4	21	7	2	2	2	1	1	1	1	1	40	12	-71%
6.6/11kV CB (GM) Secondary	HV	Each	31	53	63	122	96	158	157	157	157	157	157	157	157	365	1,257	244%
33kV Tower	EHV	Each	1	-	-	-	-	25	25	25	25	25	25	25	25	1	200	19900%
LV Pillar (OD at Substation)	LV	Each	63	76	105	189	189	111	111	111	111	111	111	111	111	622	891	43%
LV UGB & LV Pillars (OD not at Substation)	LV	Each	236	148	230	126	117	218	218	218	218	218	218	218	218	857	1,746	104%
132kV OHL (Tower Line) Conductor	132kV	Km	8	40	32	12	37	10	14	12	8	12	14	16	4	128	90	-30%
Cut Out (Metered)	LV	Each	7,381	8,624	9,977	7,355	7,135	6,311	5,911	5,511	5,112	5,112	4,712	3,913	3,913	40472	40494	0%
132kV Fittings	132kV	Each	39	456	120	510	120	343	343	343	343	343	343	343	343	1,245	2,742	120%
LV Board (WM)	LV	Each	1	12	24	54	91	49	49	49	49	49	49	49	49	182	393	116%

LV Service (UG)	LV	Each	890	1,041	638	292	292	624	624	624	624	624	624	624	624	3,153	4,994	58%
Pilot Wire Underground	Other	Km	1	1	0	9	3	12	12	12	12	12	12	12	12	13	96	611%
LV Poles	LV	Each	815	1,061	812	1,588	1,588	484	484	484	484	484	484	484	484	5,863	3,872	-34%
LV Pillar (ID)	LV	Each	66	21	34	49	49	70	70	70	70	70	70	70	70	218	558	156%
6.6/11kV OHL (Conventional Conductor)	HV	Km	7	6	6	3	2	30	30	30	30	30	30	30	30	24	238	882%
33kV CB (Gas Insulated Busbars)(ID) (GM)	EHV	Each	-	-	-	11	27	18	-	-	-	7	13	-	-	38	38	0%
33kV OHL (Pole Line) Conductor	EHV	Km	-	-	2	14	-	-	-	-	-	25	25	25	26	16	101	550%
LV Service (OHL)	LV	Each	1,355	887	415	1,443	1,443	931	931	931	931	931	931	931	931	5,543	7,448	34%
LV Main (OHL) Conductor	LV	Km	19	9	8	4	4	24	24	24	24	24	24	24	24	44	188	325%
Batteries at GM HV Substations	HV	Each	215	128	109	17	18	221	221	221	221	221	221	221	221	487	1,769	263%
6.6/11kV Poles	HV	Each	1,898	1,928	1,291	1,331	1,331	158	158	158	158	158	158	158	158	7,779	1,267	-84%
33kV Pole	EHV	Each	-	44	76	273	173	60	62	62	62	62	62	62	62	566	494	-13%
33kV Switch (GM)	EHV	Each	-	-	-	-	-	3	3	3	3	3	3	3	3	-	25	#DIV/0!
6.6/11kV Switchgear - Other (PM)	HV	Each	76	31	195	56	47	17	17	17	17	17	17	17	17	405	133	-67%
6.6/11kV Transformer (PM)	HV	Each	145	81	69	49	49	34	34	34	34	34	34	34	34	393	276	-30%
33kV Fittings	EHV		4	-	14	224	-	53	53	53	53	53	53	53	53	242	423	75%
HV Sub Cable	HV	Km	-	-	2	-	-	1	1	1	1	1	1	1	1	2	5	191%
Pilot Wire Overhead	Other	Km	-	14	15	30	18	2	2	2	2	2	2	2	3	78	17	-78%
33kV OHL (Tower line) Conductor	EHV	Km	-	-	-	15	-	-	3	-	-	-	-	-	-	15	3	-80%
LV Transformers/Regulators	LV	Each	-	-	-	-	-	2	2	2	2	2	2	2	2	-	15	100%

Source: Electricity North West; CV-3 Asset Replacement; ENWL_RIIO_ED1_Network_Investment_10Jun2013

2.2.1 33kV Transformer (GM)

Here PB observes a decrease in the forecast capital expenditure for total inventions in RIIO-ED1. This, however, comes with a revision in proposed volumes, down from 164 to 34. The revised multi-year average unit cost for RIIO-ED1 is £390,000. This in essence means a rise in projected multi-year average unit costs of approximately 49 percent from the previous forecast.

The PB ageing model gives a replacement of 132 units at a projected total direct cost of £49 million. This amounts to an average unit cost of £371,212 per intervention, indicating a 5.4 percent drop in margin compared to the expenditure in Electricity North West Limited's revised investment plan.

Electricity North West Limited's revised CBRM-generated volumes of planned interventions are now 34 percent lower than those derived through the PB ageing mode. It is believed that this is a consequence of Electricity North West Limited's identification and separation of plants that could have their life expectancies extended through undergoing remedial interventions such as transformer oil regeneration.

2.2.2 6.6/11kV CB (GM) Primary

Electricity North West Limited's revised volumes are 28.4 percent lower than those generated by the PB ageing model. This difference in the number of interventions can be connected to the decision to refurbish 358 units, which will effectively reduce the expected expenditure to £31million.

There is a reduction of approximately 39 percent in total direct costs from Electricity North West Limited's initial forecast.

Results from the Parsons Brinckerhoff ageing model test analysis reveal an improvement in proposed Electricity North West Limited total forecast unit costs by 8.3 percent.

2.2.3 6.6/11kV RMU

Electricity North West Limited's proposed volume is 99 percent above what was derived from our independent modelling process.

Proposed interventions have risen from 974 to 2,498, indicating an additional 61 percent replacement projects in RIIO-ED1. These increases support the decision to issue a Suspension of Operational Practice (SoP 2013/0383/00) on switchgears known to have a particular type of defect. The volumes have been revised based on a forecast from July 2012.

Parsons Brinckerhoff recognises that the increase in volumes is justifiable when safety and availability are considered. Proposed average unit costs 36 percent lower than those from the Parsons Brinckerhoff model reflects a replacement regimes that offers customers long term value for money when measured deliverable such as ESQCR are taken into account.

2.2.4 6.6/11kV UG Cable

Electricity North West Limited's proposed outputs have been revised down from 974 kilometres to 244 kilometres (this includes cables, associated ancillary and all termination equipments needing replacements in RIIO-ED1). This is a reduction of 75 percent.

This revised intervention figure is 73 percent lower than that generated by the Parsons Brinckerhoff ageing model. Where immediate interventions cannot be undertaken to replace these underground assets, Electricity North West Limited employ a risk attendant approach through applicable mitigation methods. This objective is anticipated to be achieved through an identified replacement strategy meant to span a period 32 years spread over four RIIO review periods..

Proposed RIIO-ED1 expenditure of £25 million is 8 percent higher than has been anticipated by the Parsons Brinckerhoff model process. While these percentage differences and outputs are comparable, we recommend that the effects of inflation and RPEs should be highlighted to Ofgem.

2.2.5 132kV Transformer

The revised volume for combined replacement and refurbishment interventions is now 31, down from the initial 33. Expenditure has been revised to £20 million to undertake a mix of both programmes, with the majority of intervention activities taking place under replacement projects at £19 million.

Although the forecasts are below our predicted projections, asset-life extension strategies represent only 5 percent of the intervention projects. We recommend that further details are specified in the business case supporting expenditure for refurbishment as more scrutiny from Ofgem is likely to surface on this aspect.

2.2.6 132kV Tower

Since our 2012 review the volumes of combined replacement and refurbishment programmes has increased from 636 to 3,456. This is an approximate 440 percent rise in proposed volumes. We assume that this sudden increase in volumes may be due to the previous data provided not being substantial enough to attain accurate outputs from CBRM.

Only 200 of the 3,456 projects forecast in RIIO-ED1 are refurbishment. We therefore believe there is a likelihood Ofgem may want to examine this more closely. However, we believe that the combined average unit cost, which is about 12 percent lower, will meet the regulator's approval and reduce the potential for scrutiny.

2.2.7 6.6/11kV Switch (GM)

Volumes of 6.6/11kV ground mounted switch units decrease by approximately 19 percent. Forecast volumes for the replacement programme are approximately 46% lower than those generated via the Parsons Brinckerhoff ageing model, reflecting a proficient scheme targeted at fuse switch units with particular defects.

Forecast capex 12.5 percent lower than the Parsons Brinckerhoff recommended value of £37.8 million suggests a cost effective strategy.

2.2.8 33kV Tower

Parsons Brinckerhoff's ageing model forecasts 307 total interventions at a cost of £12.5million. Electricity North West Limited's revised figures forecast 200 replacement projects and 364 refurbishment projects at a cost £14million. Projected average unit costs for intervention programmes are approximately 64 percent lower than those from the Parsons Brinckerhoff model. It is likely that the increase in proposed volumes for replacement is due to updated condition data collected in 2012 giving a truer picture. We believe no scrutiny will surface for this asset type.

2.2.9 Wall Mounted LV Boards

Revised proposed volumes are around 84 percent lower than Parsons Brinckerhoff's recommended volumes. This is due to more recent asset condition surveys undertaken to record accurate data into Ellipse, the Master Asset Management System (MAMS) which is Electricity North West Limited's asset register for LV switchgears categories.

£7million has been proposed for the delivery of replacement project activities. No commentary is given to suggest how a no-cost value has been reached for the refurbishing of 83 wall mounted units in RIIO-ED1. It is recommended that substantial commentary on the mode of delivering the refurbishment exercise is provided to justify the proposed capex in CV5 for this asset type.

2.2.10 LV Poles

Electricity North West Limited explains in its WJBP Commentary that it is practical to replace assets as they deteriorate. The total population of LV poles to undergo replacement and refurbishment work is 15,593 units. Of this population, 48 percent will be replaced while the remaining 52 percent will undergo some form of restoration. The figure of 15,593 represents a drop of approximately 48 percent compared to the initial 30,075. This revised volume is 23.6 percent lower than what has been recommended via our independent modelling exercise.

The case made to justify this drop in expenditure levels is justified by the decision to combine replacement and refurbishment programmes, therefore maximising the benefits of investment on poles identified to be in most need of intervention.

We believe that no additional assessment of the investment plan proposed for this asset type will be undertaken by the regulator.

2.2.11 6.6/11kV Pole

Observations here are similar to those for LV Poles. Volumes captured for specific intervention in the asset register have been identified based on the policy for maintenance and refurbishment for overhead lines (CoP421). Of the population of 29,474 units to be addressed, 83 percent of proposed intervention activities fall under refurbishment programmes, representing the largest bulk of delivery activities proposed for this asset type in RIIO-ED1.

The revised forecast of interventions is approximately 30 percent higher than that of the Parsons Brinckerhoff ageing model. However, the total direct cost of £17 million is 75 percent lower. This suggests a more efficient delivery of intervention costs and we do not believe this will rouse further scrutiny.

However, we do recommend that Electricity North West Limited states in the business case that the cheaper cost of delivery of 6.6/11kV overhead pole line intervention projects is a consequence of a review of framework contract charges and comparison to other industry rates.

Composition Of Intervention Projects for Individual Asset Types								
	Volumes/Interventions			Capital Expenditure			Programme Composition of Projects	
Asset Type	RIIO-ED1 Replacement Volumes	RIIO-ED1 Refurbishment Volumes	RIIO-ED1: Total Volumes	RIIO-ED1 Replacement Direct Costs (£m)	RIIO-ED1 Refurbishment Direct Costs (£m)	RIIO-ED1: Total Expenditure (£M)	Replacement Programme (%)	Refurbishment Programme (%)
33kV Transformer (GM)	87	109	196	34	6	40	44.4	55.6
6.6/11kV CB (GM) Primary	866	358	1224	32	5	37	29.2	70.8
33kV UG Cable (Non Pressurised)	108	0	108	32	0	32	100	0
132kV CB (Gas Insulated Busbars)(ID) (GM)	35	8	43	28	0.16	28.16	81.4	18.6
6.6/11kV RMU	2498	-	2498	27	0	27	100	0
6.6/11kV UG Cable	244	-	244	25	-	25	100	0
6.6/11kV Transformer (GM)	1412	-	1412	19	-	19	100	0
LV Main (UG Plastic)	200	-	200	19	-	19	100	0
132kV Transformer	17	14	31	19	1	20	52	48
132kV Tower	200	1892	2092	16	31	47	9.6	90.4
6.6/11kV Switch (GM)	2536	-	2536	14	-	14	100	0
132kV UG Cable (Non Pressurised)	12	-	12	10	-	10	100	0
6.6/11kV CB (GM) Secondary	1257	70	1327	9	0.6	9.6	94.7	5.3
33kV Tower	200	364	564	8	6	14	35.5	64.5
LV Pillar (OD at Substation)	891	1474	2365	8	1	9	37.7	62.3
LV UGB & LV Pillars (OD not at Substation)	1746	-	1746	8	-	8	100	0
132kV OHL (Tower Line) Conductor	90	-	90	8	-	8	100	0

132kV Fittings	3142	-	3142	8	-	8	100	0
Cut Out (Metered)	40494	-	40494	8	-	8	100	0
LV Board (WM)	96	83	179	7	0	7	53.6	46.4
LV Service Underground	4994	-	4994	7	-	7	100	0
Pilot Wire Underground	96	-	96	5	-	5	100	0
LV Poles	3872	11721	15593	5	5	10	24.8	75.2
6.6/11kV Pole	1267	28207	29474	2	13	15	4.3	95.7
132kV CB (Air Insulated Busbars)(ID) (GM)	-	-	-	-	-	-	-	-

Source: Electricity North West Limited: CV3 and CV5 Tables; ENWL_RIIO_ED1_Network_Investment_10Jun2013

2.3 Justification of overall scale of capex and balance between programmes

Parsons Brinckerhoff has analysed the overall scale of Electricity North West Limited's proposed capex and the balance between its programmes, based on data provided within 'E NWL_RIIO_ED1_Network_Investment_10Jun2013.xlsm'.

The programmes listed in the C10 table include five for which there are no values for either DPCR5 or RIIO-ED1 (Within Price Control, Transmission Connection Points, Operational IT & Telecoms, High Value Projects (ex ante) and High Impact Low Probability (HILP)). There are also no values for the category Demand and Pre 2005 DG Connections. These lines have been excluded from any analysis.

In this section we examine the balance between programmes in the RIIO-ED1 expenditure plan. In order to review this we have looked at the percentage of total capex allocated to each programme in RIIO-ED1, how these have changed compared to DPCR5 and whether they are justified properly in the narrative documents. We have also looked specifically at the ratios of expenditure between Asset Replacement and Refurbishment, Civil Works and Reinforcement.

2.3.1 Percentage of capex per programme

To assess the overall scale of capex and balance between programmes, it is useful to compare the RIIO-ED1 figures with those from DPCR5.

The table below summarises capex by programme across DPCR5 and RIIO-ED1: total spend, average spend per year and the percentage of total capex each category represents. The final three columns present the change in values between DPCR5 and RIIO-ED1.

The subsequent table provides the same data, grouped into categories.

£207.4M is allocated to High Value Projects (re-openers) during RIIO-ED1. There was zero expenditure in this programme during DPCR5. This expenditure covers work related to the proposed construction of a nuclear power station in Moorside in Cumbria. Given its large value and the uncertainty around the project, and the impact it has on overall conclusions on the scale of capex, we have also provided the same two tables as above with this value removed. *All analysis in this section 2.3 of the report is based on the High Value Projects (re-openers) being excluded.*

In all four tables, large changes (greater than 3%) in the percentage of total capex are in red text.

Summary of capex by Programme (including High Value Projects (re-openers))										
Gross Costs		**DPCR5**			**RIIO-ED1**			**Change in**		
Category	**Programme**	**£M Total**	**£M Ave p/y**	**% of total capex**	**£M Total**	**£M Ave p/y**	**% of total capex**	**£M Total**	**£M Ave p/y**	**% of total capex**
Core	Diversions	18.2	3.6	3.4%	28.3	3.5	2.7%	10.1	-0.1	-0.7%
Core	Reinforcement – General	82.1	16.4	15.4%	98.7	12.3	9.4%	16.5	-4.1	-6.0%
Core	Reinforcement - DSM Payments to avoid Reinforcement	0.3	0.1	0.0%	2.0	0.3	0.2%	1.7	0.2	0.1%
Core	Fault Level Reinforcement	2.6	0.5	0.5%	14.9	1.9	1.4%	12.3	1.3	0.9%
Core	ESQCR	29.3	5.9	5.5%	-	0.0	0.0%	-29.3	-5.9	-5.5%
Core	Asset Replacement	240.2	48.0	45.1%	389.0	48.6	37.2%	148.8	0.6	-7.9%
Core	Refurbishment	44.5	8.9	8.4%	112.1	14.0	10.7%	67.6	5.1	2.4%
Core	Civil Works	26.4	5.3	4.9%	79.2	9.9	7.6%	52.8	4.6	2.6%
Core	Legal and Safety	13.9	2.8	2.6%	41.4	5.2	4.0%	27.6	2.4	1.4%
Core	QoS	30.0	6.0	5.6%	-	0.0	0.0%	-30.0	-6.0	-5.6%
Core	High Value Projects (re-openers)	-	-	0.0%	207.4	25.9	19.8%	207.4	25.9	19.8%
Non Core	Flooding	7.9	1.6	1.5%	10.3	1.3	1.0%	2.4	-0.3	-0.5%
Non Core	BT21CN	22.7	-	4.3%	-	0.0	0.0%	-22.7	0.0	-4.3%
Non Core	Technical losses	-	-	0.0%	10.0	1.3	1.0%	10.0	1.3	1.0%
Non Core	Environmental	3.1	0.6	0.6%	6.7	0.8	0.6%	3.6	0.2	0.1%
Non Core	CNI	-	-	0.0%	2.6	0.3	0.2%	2.6	0.3	0.2%
Non Core	Black Start	-	-	0.0%	14.7	1.8	1.4%	14.7	1.8	1.4%
Non Core	Rising mains and laterals	3.0	0.6	0.6%	16.9	2.1	1.6%	13.9	1.5	1.0%
Stand Alone Funding (RAV)	Undergrounding Within/ Outside designated areas	6.1	1.2	1.1%	9.0	1.1	0.9%	2.9	-0.1	-0.3%
Stand Alone Funding (RAV)	Worst Served Customers	2.2	0.4	0.4%	3.4	0.4	0.3%	1.1	0.0	-0.1%
Total		**532.4**	**106.5**	**100.0%**	**1,046.5**	**130.8**	**100.0%**	**514.1**	**24.3**	**0.0%**

Summary of capex by Category (including High Value Projects (re-openers))									
Gross Costs	DPCR5			RIIO-ED1			Change in		
Category	£M Total	£M Ave p/y	% of total capex	£M Total	£M Ave p/y	% of total capex	£M Total	£M Ave p/y	% of total capex
Core	487.4	97.5	91.5%	973.0	121.6	93.0%	485.6	24.2	1.4%
Non Core	36.7	7.3	6.9%	61.2	7.6	5.8%	24.4	0.3	-1.1%
Stand Alone Funding (RAV)	8.3	1.7	1.6%	12.4	1.5	1.2%	4.0	-0.1	-0.4%
Total	**532.4**	**106.5**	**100.0%**	**1,046.5**	**130.8**	**100.0%**	**514.1**	**24.3**	**0.0%**

Summary of capex by Programme (excluding High Value Projects (re-openers))										
Gross Costs		**DPCR5**			**RIIO-ED1**			**Change in**		
Category	**Programme**	**£M Total**	**£M Ave p/y**	**% of total capex**	**£M Total**	**£M Ave p/y**	**% of total capex**	**£M Total**	**£M Ave p/y**	**% of total capex**
Core	Diversions	18.2	3.6	3.4%	28.3	3.5	3.4%	10.1	-0.1	0.0%
Core	Reinforcement – General	82.1	16.4	15.4%	98.7	12.3	11.8%	16.5	-4.1	-3.7%
Core	Reinforcement - DSM Payments to avoid Reinforcement	0.3	0.1	0.0%	2.0	0.3	0.2%	1.7	0.2	0.2%
Core	Fault Level Reinforcement	2.6	0.5	0.5%	14.9	1.9	1.8%	12.3	1.3	1.3%
Core	ESQCR	29.3	5.9	5.5%	-	0.0	0.0%	-29.3	-5.9	-5.5%
Core	Asset Replacement	240.2	48.0	45.1%	389.0	48.6	46.4%	148.8	0.6	1.3%
Core	Refurbishment	44.5	8.9	8.4%	112.1	14.0	13.4%	67.6	5.1	5.0%
Core	Civil Works	26.4	5.3	4.9%	79.2	9.9	9.4%	52.8	4.6	4.5%
Core	Legal and Safety	13.9	2.8	2.6%	41.4	5.2	4.9%	27.6	2.4	2.3%
Core	QoS	18.2	3.6	3.4%	28.3	3.5	3.4%	10.1	-0.1	0.0%
Core	High Value Projects (re-openers)									
Non Core	Flooding	7.9	1.6	1.5%	10.3	1.3	1.2%	2.4	-0.3	-0.3%
Non Core	BT21CN	22.7	-	4.3%	-	0.0	0.0%	-22.7	0.0	-4.3%
Non Core	Technical losses	-	-	0.0%	10.0	1.3	1.2%	10.0	1.3	1.2%
Non Core	Environmental	3.1	0.6	0.6%	6.7	0.8	0.8%	3.6	0.2	0.2%
Non Core	CNI	-	-	0.0%	2.6	0.3	0.3%	2.6	0.3	0.3%
Non Core	Black Start	-	-	0.0%	14.7	1.8	1.8%	14.7	1.8	1.8%
Non Core	Rising mains and laterals	3.0	0.6	0.6%	16.9	2.1	2.0%	13.9	1.5	1.4%
Stand Alone Funding (RAV)	Undergrounding Within/ Outside designated areas	6.1	1.2	1.1%	9.0	1.1	1.1%	2.9	-0.1	-0.1%
Stand Alone Funding (RAV)	Worst Served Customers	2.2	0.4	0.4%	3.4	0.4	0.4%	1.1	0.0	0.0%
Total		**532.4**	**106.5**	**100.0%**	**839.0**	**104.9**	**100.0%**	**306.6**	**-1.6**	**0.0%**

Summary of capex by Category (excluding High Value Projects (re-openers))									
Gross Costs	DPCR5			RIIO-ED1			Change in		
Category	£M Total	£M Ave p/y	% of total capex	£M Total	£M Ave p/y	% of total capex	£M Total	£M Ave p/y	% of total capex
Core	487.4	97.5	91.5%	765.5	95.7	91.2%	278.2	-1.8	-0.3%
Non Core	36.7	7.3	6.9%	61.2	7.6	7.3%	24.4	0.3	0.4%
Stand Alone Funding (RAV)	8.3	1.7	1.6%	12.4	1.5	1.5%	4.0	-0.1	-0.1%
Total	**532.4**	**106.5**	**100.0%**	**839.0**	**104.9**	**100.0%**	**306.6**	**-1.6**	**0.0%**

2.3.2 Categories

Across both price control periods, Core costs represent the vast majority of capex (£487.4M or 91.5% for DPCR5 and £765.5M or 91.2% for RIIO-ED1).

Non-Core costs increase slightly from 6.9% of total capex (£36.7M) during DPCR5 to 7.3% (£61.2M) during RIIO-ED1.

Stand Alone Funding (RAV) accounted for 1.6% of total capex during DPCR5 (£8.3M) but decreases in percentage terms to 1.5% for RIIO-ED1 (£12.4M).

2.3.3 Programmes

There are five programmes for which the percentage of total capex figure changes significantly (by more than 3%):

2.3.3.1 Reinforcement - General

15.4% of total capex (£82.1M) in DPCR5 and 11.8% of capex (£98.7M) in RIIO-ED1.

The Reinforcement sections of '130528 BPDT Commentary v2_draft.docx' are empty. We were, however, provided with 'C12 Commentary V2.docx', which outlines Electricity North West Limited's Reinforcement programme, although this document was incomplete (for example, there is a note on pp.6 to add a section on voltage and harmonic outputs and on pp.7 there are figures missing).

The methodology of developing and pricing Reinforcement expenditure forecasts is explained in detail.

In 2012, Cambridge Economic Policy Associates (CEPA) was commissioned to produce an energy forecast to 2023, and this was updated in January 2013. Parsons Brinckerhoff believes that it is positive that independent experts have been recruited to assist with this process.

Further, Electricity North West Limited's own model, the Future Capacity Headroom model, and its use, is explained. We recommend that it should be ensured that the added value of using this model is made clear.

On pp.7, it is stated that Ofgem's regional Transform model is customised by Electricity North West Limited. It isn't clear what this customisation involves and we recommend that this be made explicit

Six Reinforcement expenditure forecasts have been produced: four low-carbon scenarios from DECC; a base forecast without significant penetration of low-carbon technologies; and a sixth scenario including the connection of a nuclear power station at Moorside. We believe that it could be made clearer which forecast is being used as the basis for the investment figures.

2.3.3.2 ESQCR

DPCR5 saw 5.5% of capex (£29.3M) spent on this programme. There is no spending forecast on ESQCR during RIIO-ED1 as Electricity North West Limited expects that all such overhead line clearance compliance will be completed during DPCR5.

2.3.3.3 Refurbishment

Refurbishment sees the biggest increase in terms of percentage of total capex of any programme (5%). In DPCR5 8.4% of total capex (£44.5M) was spent on Refurbishment; in RIIO-ED1 it is 13.4% (£112.1M).

The WJBP explains that Cost Benefit Analysis is carried out on major asset types. Spending on refurbishment comes out of this analysis, along with use of CBRM tools. Our review of the CBAs is contained in section 5 of this report.

2.3.3.4 Civil Works

4.9% of total capex (£26.4M) in DPCR5 and 9.4% (£79.2M) in RIIO-ED1.

Increases in civil works costs have been identified within the WJBP as being down to:

- Increases associated with additional plant volumes;
- New major programmes of work on cable structures (pits, tunnels and bridges); and
- Increase in Grid and Primary works (e.g. substation dehumidifier upgrades instigated following a number of plant failures due to moisture ingress).

2.3.3.5 BT21CN

This represents 4.3% of total capex (£22.7M) in DPCR5 but has zero expenditure associated with it in RIIO-ED1.

This is BT's 21st Century Networks initiative and there is no spending forecast in RIIO-ED1. The commentary (pp.70) explains that "BT21CN is a high value project, separately funded from the Network Investment and Operational IT Programmes. Expenditure thus far has been in line with the delivery profile."

From the narrative documents, it is not clear why there is now zero expenditure forecast and we recommend that this be made explicit.

2.3.4 Ratios

Here we directly compare the ratio of expenditure between different programmes.

In this commentary, the ratios are presented as described below:

- *Price control period: Asset Replacement: Comparison category - Ratio*

2.3.4.1 Asset Replacement against Refurbishment

The ratios for spending between Asset Replacement and Refurbishment for DPCR5 and RIIO-ED1 are presented below.

- DPCR5: £240.2M:£44.5M - 5.4:1
- RIIO-ED1: £389.0M:£112.1M - 3.5:1

The ratio of Asset Replacement expenditure to expenditure on Refurbishment has decreased from 5.4:1 to 3.5:1.

This suggests a greater emphasis on refurbishing assets rather than replacing them and we believe this should not be of concern to Ofgem.

A policy of refurbishing rather than replacing, and therefore a change from the DPCR5 approach, should be clearly explained in the supporting documents.

2.3.4.2 Asset Replacement against Civil Works

The ratios for spending between Asset Replacement and Civil Works for DPCR5 and RIIO-ED1 are presented below.

- DPCR5: £240.2M:£26.4M - 9.1:1
- RIIO-ED1: £389.0M:£79.2M - 4.9:1

The ratio of Asset Replacement expenditure to expenditure on Civil Works has decreased from 9.3:1 to 4.9:1. Increases in spending on Civil Works have been explained in the previous section.

2.3.4.3 Asset Replacement against Reinforcement

Expenditure on Reinforcement is split between General and DSM Payments to avoid Reinforcement. The figures below are the total of these two.

- DPCR5: £240.2M:£82.4 - 2.9:1
- RIIO-ED1: £389.0M:£100.7M - 3.9:1

The ratio of Asset Replacement expenditure to expenditure on Reinforcement has increased from 2.9:1 to 3.9:1.

2.4 Parsons Brinckerhoff conclusion

It is noticeable that the percentage of total capex figures are very similar between DPCR5 and RIIO-ED1.

There are five programmes for which the percentage of total capex figures are, by our judgement, significantly different. Two of these (ESQCR and BT21CN) are due to there being zero expenditure forecast for RIIO-ED1. The reason for zero expenditure on BT21CN should be explained clearly. The figures for the remaining programmes (Reinforcement - General, Refurbishment and Civil Works) are explained and justified through the narrative documents.

At the category level, the differences are very small. The biggest change is in Non-Core, which has increased from 6.9% to 7.3%.

There is nothing in these figures that we feel will be of particular concern to Ofgem.

The ratios we have examined, show that the ratio of Asset Replacement to Refurbishment and Civil Works have decreased, while the ratio of Asset Replacement to Reinforcement has increased.

Again, we feel that nothing here will be of concern to Ofgem.

Our recommendations are:

- Complete the reinforcement commentary

- Explain the benefits of the Future Headroom Capacity model
- Explain how the Transform model is customised
- State more clearly which forecast has been used as the basis for investment figures
- Explain why there is zero expenditure forecast for BT21CN
- Explain further any policy on refurbishment versus replacement (or reinforcement versus replacement)

3 LINKAGE TO OUTPUTS

Ofgem has determined a number of outputs which the distribution companies must seek to attain in the RIIO-ED1 period. Some of these will be statutory (e.g. health and safety requirements) while companies will be incentivised to attain others through financial penalties and rewards.

For each output category the rationale and justification for the expenditure will need to be developed in the Well Justified Business Plan.

Parsons Brinckerhoff has reviewed Electricity North West Limited's draft WJBP with regard to outputs. Our review sought to answer the following questions as set out in the scope of our work:

- Has Electricity North West Limited clearly identified the outputs that the investment will deliver?
- Has Electricity North West Limited articulated the benefit that it expects?
- Has Electricity North West Limited supported the choice of target appropriately?
- Do the projections appear to represent an efficient forecast?

In answering the first three of these questions Parsons Brinckerhoff has examined each of the outputs in-turn and assessed the WJBP description on a check-list basis. In answering the final question we have relied on our experience in assessing efficiency generally. In order to undertake a comprehensive review of efficiency we would need access to comparative cost data from other DNOs. This data is unavailable and we therefore regard a full efficiency test as outside the scope of this work. Instead we provide our own opinion where possible.

3.1 Safety

Electricity North West Limited is mandated to comply with all applicable legislation with regard to health and safety and Ofgem has not established a separate incentive scheme for this output measure. Investment to reduce specific safety risk is aimed at the following areas:

- Asbestos management
- Safe climbing
- Site security

Parsons Brinckerhoff believes that Electricity North West Limited has clearly identified the outputs which its investment will deliver. The commentary in the WJBP explains the outputs in relation to site security, tower climbing, asbestos management, training and education.

While we understand that the WJBP is targeted at a general audience and does not contain detailed analysis of every level of expenditure we found the section on security to be quite vague in terms of the actual expenditure items to improve security. We recommend that the analysis in the annexes should contain more detailed information. In some cases the description does not include the number of assets or the level of expenditure being proposed for RIIO-ED1. This is particularly true for the site security expenditure category. Only in Table 5.3.2 is there a one line expenditure item but this is not broken down into the four output categories.

Under Tower Climbing a target of 3,000 Latchway Systems installations has been identified by 2023. We would recommend that Electricity North West Limited explains how this target has been set and what the effects would be in terms of costs / benefits of an accelerated or delayed programme.

Similarly, the asbestos management programme mentions the number of asbestos removals at both high and low risk sub stations. We recommend that the justification for these targets is made explicit.

Given the lack of information relating to the expenditure on safety it has not been possible to comment on whether the expenditure forecasts can be considered efficient.

Checklist questions	Comments
Outputs identified?	Outputs partially identified, actual numbers needed for some categories
Benefit articulated?	In general terms only
Target level supported?	No
Are projections efficient?	Not enough information to answer

3.2 Social Obligations

This output relates to expenditure targeted at vulnerable customers and wider social obligations. Electricity North West Limited has a targeted corporate social responsibility index scoring.

Electricity North West Limited maintains a priority services register (PSR) to identify those customers most dependent on its services. PSR customers receive priority support during power cuts.

To achieve its outputs Electricity North West Limited intends to invest its own funds in comprehensive data systems and customer support communication. Electricity North West Limited has committed £1m per annum during RIIO-ED1 for these measures.

Electricity North West Limited has identified areas of high concentration of vulnerable customers and it intends to spend £0.6m in the first 2 years of RIIO-ED1 to make the network more reliable. Extra funding will be targeted at improving reliability at sub-stations in areas of high vulnerable customer concentration.

Electricity North West Limited's data strategy will help to identify those customers in fuel poverty

3.2.1 Parsons Brinckerhoff review:

We believe that the WJBP describes adequately those areas where Electricity North West Limited plans to spend money on but the outputs of that expenditure are rather tenuous in some cases. Targets for the outputs are not always clear and it will therefore be difficult to measure if the targets have been met or not.

We believe that the analysis would benefit from the inclusion of specific measureable targets during RIIO-ED1 including for example, number of new and existing customer service staff to be trained.

Targets and expenditure are more explicit for the resilient supplies to vulnerable locations category and for reducing fuel poverty by reducing the overall level of prices.

Checklist questions	Comments
Outputs identified?	Outputs partially identified, actual numbers needed for some categories
Benefit articulated?	In some categories
Target level supported?	In some categories
Are projections efficient?	Not enough information to answer

3.3 Reliability and Availability

The WJBP states that reliability (power cuts) and availability (time without power) are the two key measures of network performance that customers experience most directly. To meet Ofgem targets for CIs and CMLs, Electricity North West Limited has a targeted asset replacement programme, additional remote control and automation programmes and new techniques and processes to improve fault restoration.

Electricity North West Limited has identified targets for output performance in the following areas:

- Quality of Supply
- Worst-served customers
- Network resilience
- Asset Health
- Asset Loading

3.3.1 Parsons Brinckerhoff Comments:

Electricity North West Limited has clearly identified the outputs which the investment is designed to deliver in every one of the above categories. The targets set are measurable and infer a direct benefit to customers.

Investment to meet the outputs has been identified and justified in section 5 of the WJBP.

We recommend that the CBAs undertaken by Electricity North West Limited reflect a range of options considered and that the preferred option which is most beneficial in improving reliability and availability is mapped back to this section.

Checklist questions	Comments
Outputs identified?	Yes
Benefit articulated?	Yes
Target level supported?	Yes
Are projections efficient?	Assumed given historical investment levels

3.4 Customer Satisfaction

This output consists of three categories: a customer satisfaction survey; complaints resolution and stakeholder engagement.

3.4.1 Parsons Brinckerhoff Comments:

We believe that Electricity North West Limited has adequately identified the outputs it wishes to deliver in this category. Measuring the benefits to customers is not very easy for some of these such as undertaking a satisfaction survey or greater stakeholder engagement. For this reason it is also difficult to set targets.

We agree that targets should be set for complaints resolution both for reducing the number of complaints and for reducing the time taken to solve complaints. However the rationale for the new target level has not been explained – it would be useful if Electricity North West Limited could provide some evidence that its new targets are in line with best industry practice.

Finally, no expenditure levels have been identified to specifically meet these output objectives and therefore an efficiency assessment is not possible.

Checklist questions	Comments
Outputs identified?	Yes
Benefit articulated?	Yes
Target level supported?	Only for complaints resolution
Are projections efficient?	Not possible to assess

3.5 Connections

We believe that the explanation of this output measure needs to be developed more fully in the (draft) WJBP.

The output measures here include compliance with full competition regulations for connections, connection cost quotation times (with a number of working days), connection completion times (working days) and guaranteed standards incentives.

Electricity North West Limited has identified measurable targets for these but the justification of the target levels has not been established. No linkage to expenditure has been established.

Checklist questions	Comments
Outputs identified?	Yes
Benefit articulated?	No
Target level supported?	No rationale for target levels
Are projections efficient?	Not possible to assess

3.6 Environmental Impact

Output measures in this category refer to Electricity North West Limited's own Business Carbon Footprint (reducing carbon emissions from own activities), Oil Leakages, and Undergrounding of overhead lines and losses reduction.

Electricity North West Limited has established a target for each of these outputs. In the case of undergrounding cables a length of km measure is targeted while for the others there is a reduction in emissions, litres leaked or MWh losses saved.

For the oil leakage and loss reduction output targets, the target has been substantiated by a CBA. Undergrounding has been informed by customer feedback. However, the rationale for the 10% reduction in carbon footprint should also be explained.

Checklist questions	Comments
Outputs identified?	Yes
Benefit articulated?	Yes
Target level supported?	Yes (except carbon footprint)
Are projections efficient?	Yes by CBAs

ANNEX 18: IT STRATEGY

Electricity North West Limited
Registered Office:
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Registered no: 2366949 (England)

Contents

1. Executive Summary

We use IT as an enabler of customer service rather than an end in itself. As such, the role of the IT strategy is to provide the direction required for an evolving IT&T function whose core purpose is to support the delivery of our company goals and deliver business value.

Our IT strategy for RIIO-ED1 and the plans that it supports, enable us to deliver:

- Day-to-day business as usual requirements
- Transformational business change
- Organisational whole-life cost efficiency goals
- New requirements emerging from the move to a low carbon economy and smart networks

Our 2012 benchmarking exercise with Gartner[1] suggested that our operating costs were approximately £1 million higher than industry peers. However, our IT strategy and plans for RIIO-ED1 will not only deliver the enhanced capability needed for the future, but will also reduce costs significantly from previous levels. Hence, we aim that by 2023 we will have removed almost 30% of our IT & Telecoms (IT&T) business support costs compared with the 2011-12 levels.

[1] Gartner are ISO9001 certified, employ over 100 benchmarking professionals worldwide, and benchmark around 5,500 client environments annually.

2. Purpose

The primary purpose of IT investment throughout DPCR5 and RIIO-ED1 is to provide reliable and affordable IT systems and services that support our business goals. Therefore our IT strategy is one that:

- Enables delivery of our RIIO-ED1 plans
- Adds value to our business through innovation and continuous improvement
- Supports emerging future network requirements
- Promotes development of successful partnership with key suppliers and service providers
- Is responsive to changing stakeholder and user needs
- Aspires to upper-quartile performance for IT&T business support costs
- Is environmentally and socially responsible in the delivery and management of IT services.

In particular, this strategy should be read in conjunction with Annex 13 – Smart Grid Strategy.

3. Key Principles

The key principles for our IT strategy are to:

- Invest in a commercial off-the-shelf (COTS) network management solution to ensure there is a sustainable, reliable and affordable platform to support the anticipated scale of the functional enhancement deemed to be required to meet the future requirements of the emerging Smart Grid
- Exploit prior investment in strategic systems such as the Geospatial Information System (GIS) to reduce reliance on legacy technologies and improve asset data quality and accuracy
- Re-implement the SAP platform on standard functionality to streamline Back Office processes
- Enhance customer service through consolidated customer information, integrated telephony and closer integration between front office and real time systems
- Take advantage of the increasing use of devices such as smart phones to drive efficiency and productivity, in particular through extending the use of mobile technologies for field data capture and provision of timely access to electronic records
- Strengthen the potential for innovation through enhanced business intelligence and the ability to explore innovation opportunities via a flexible sourcing model and agile infrastructure
- Increase affordability and reliability through convergence of the corporate IT and Operational Technology estates into two data centres, and continued exploitation of our high performance 21st Century telecommunications network (ENW21CN), built to mitigate the risks arising from the BT 21st Century project . This will then enable further convergence of back office and operational IT teams, delivery and management processes, and supporting technologies.

4. Key Investments

4.1 Non-operational IT Strategy

The first half of DPCR5 was dominated by securing complete independence from United Utilities and strengthening our long-term relationship with a new IT service provider.

2012-13 saw the implementation of a centralised customer contact centre, enhanced asset management solutions, enhanced reporting capabilities for operations and preparatory work for the mobilisation of our field force and implementation of enhanced work management solutions. Additional investment was also made in the areas of technical refresh to ensure continuing levels of reliability and ongoing compliance with regulatory and legislative requirements. For example, foundation work for the migration from Windows XP (which goes out of extended support in April 2014) to Windows 7 is well underway and will complete in 2013-14.

Over the remainder of DPCR5, we will be investing in a number of strategic technology-enabled initiatives including:

- Expanding the use of mobile technologies to improve the efficiency and productivity of the field force through extending field data capture and timely access to electronic records
- Increasingly effective use of work and asset management solutions and geospatial technologies through a rationalised suite of systems and improved asset data quality and accuracy
- Enabling augmented customer service by investment in a strategic, central customer information system, an integrated telephony solution and closer integration with Work Management and Network Management systems
- Enhancing our back office efficiency and reducing our associated business support costs by using appropriate tools and adopting industry best practice and processes;
- Expanding our decision making capabilities, reporting efficiency, and improving integrity across the organisation through a roadmap of Management Information (MI) projects delivering incremental solutions using a strategic and cost-effective platform
- Optimising the overall IT and telecommunications estate to achieve lowest whole life costs through, for example, data centre consolidation, continued exploitation of our high performance ENW21CN network, and convergence and consolidation of back-office and operational IT teams, delivery and management processes, and technologies
- Implementation of call centre, scheduling and dispatch capabilities to support the smart meter roll out which starts in September 2015.

Having implemented this future-proof, flexible and cost effective IT estate, investment through RIIO-ED1 is that of pragmatic cost minimisation. As with any asset, IT assets and applications degrade over time. As they age, the cost to operate also increases as they require increasing resource and potentially scarcer skills to operate, support and maintain. Therefore the programme is focussed primarily on refresh activities, with all IT-enabled discretionary business change being self-funded from the benefits it delivers, thus ensuring our strategy is the most affordable solution for our customers.

4.2 Operational IT Strategy

During early DPCR5, as the potentially significant impact of the low carbon economy and smart meter roll out became clearer, we concluded that continuing to develop bespoke real time systems in house would incur significant additional cost and present an increasing risk to the business in the future sourcing and training of additional system experts due to the scale and complexity of future “Smart” requirements.

In order to address these issues we conducted a number of expert reviews of many elements of our DPCR5 Operational IT strategy including our Network Management System (NMS) platform, Supervisory Control and Data Acquisition (SCADA) platform, security infrastructure, data centre infrastructure and operational radio infrastructure. These reviews focused on systems being fit for purpose in terms of current and future functionality (sustainability), simplification of infrastructure complexity (reliability) and reduction in total cost of ownership (affordability).

The recommendations from the above reviews, along with reference client engagements with both GB DNOs and US electricity and gas companies, led to the creation of a strategy for the Operational IT investment which runs through the remainder of the DPCR5 period and throughout the RIIO-ED1 period. The core investments within this strategy are:

- Implementation of a scalable and reliable strategic NMS platform allowing for the future deployment of new smart grid technologies as they are developed through research and supplier partnerships. This transformation of our Operational IT core systems will also create benefits from integration of smart meter data much earlier in the investment period than would have been previously possible
- Asset data quality initiatives in order to simplify the creation of HV and LV connectivity models, enable future integration of 'smarter' analysis tools and prepare our systems for taking advantage of smart meter data once it is available
- Consolidation of core infrastructure into two highly resilient and secure purpose-built data centres that will also support storage of smart meter data once available
- Implementation of our smart meter data infrastructure to support our Smart Energy Code obligations and to realise the benefits for usage of smart meter data within network monitoring and management activities eg utilising profile data and alerts for advanced management of the distribution network
- Continued investment in the extension and refresh of our Remote Terminal Unit (RTU) and telecoms assets in order to provide greater reliability in the face of increased demand through significantly increased automation
- Implementation of outputs from innovation projects such as contract management (C_2C), and energy management (CLASS) as well as other DNO initiatives.

As with Non-Operational IT, refresh activities will be undertaken balancing cost reduction with risk mitigation.

5. Strategy Execution

Efficient execution of our IT strategy will be achieved through the right-sizing, right-skilling and right-sourcing of our IT services to match the current and future requirements of the IT estate through use of internationally recognised change management standards and supported by appropriate collaboration tools such as SharePoint.

Opportunities to optimise processes will be regularly reviewed to ensure the forecast IT&T business support efficiencies are achieved.

5.1 Project Portfolio Management (PPM) and Portfolio Management Office (PMO)

The IT&T PPM capability and supporting Portfolio Management Office (PMO) is well established and operates using the Office of Government Commerce (OGC) P3O[2] and

[2] The purpose of the Portfolio, Programme and Project Offices (P3O) guidance is to provide universally applicable guidance that will enable individuals and organisations to successfully establish, develop and maintain appropriate structures to support all types of business change.

Management of Portfolio standards of best practice. The PMO supports the definition and delivery of our portfolio of IT-enabled change through the provision of information management capabilities including:

- Financial Management - the preparation and presentation of financial data including project and programme forecasts against sanction value and budget
- Delivery Assurance - a common approach to assurance activities including internal/external audits and, where applicable, the engagement of third party assurance providers
- Controls – detailing a consistent approach to the management of risk, change and approvals.

The PMO will continue to operate as a coordinating function, ensuring that change is delivered consistently and well, through standard processes and competent staff. It provides standards, consistency of methods and process and knowledge management. It also provides strategic oversight, scrutiny and challenge across the IT&T portfolio of projects and programmes. The 'Centre of Excellence' is a function of the PMO and provides a focal point for driving the implementation of improvements to increase the IT&T organisation's capability and capacity in programme and project delivery.

5.2 Governance

Robust governance is at the heart of the IT&T function's approach to the execution of the IT strategy. Investment approval, technical assurance, risk management, change management and the release of contingency will continue to be managed in line with our Internal Control Manual and IT&T governance processes.

For major projects and programmes, Programme or Project Steering Groups (PSGs) meet regularly, monitoring progress, performance and risk, and providing a forum for sponsors and key stakeholders to challenge and direct the delivery team appropriately.

The Capital Programme Management Group (CPMG) oversees the delivery of all IT&T led initiatives. The main focus for this forum will continue to be ensuring that the initiatives and programmes being progressed by IT&T are fully aligned to our IT&T strategy and emerging business needs.

The virtual Design Authority (DA) team will continue to utilise both in-house and external expertise to provide technical assurance of all IT-enabled change.

5.3 Service Management

The first half of DPCR5 saw the strategic development of our long-term relationship with a new IT service provider including the introduction of an ITIL[3]-based service management model. Additional efficiencies were achieved through re-negotiation of contracts and Service Level Agreements for key non-operational systems.

To support our strategic aims, a review was undertaken during 2012-13, post separation from United Utilities, to benchmark our operating model and cost-to-serve. Taking the output of the review we are seeking to exploit opportunities during 2013-14 and 2014-15 to right-size and right-source a number of service management functions for which capabilities and

[3] The Information Technology Infrastructure Library (ITIL) is a set of internationally recognised practices for IT service management (ITSM) that focuses on aligning IT services with the needs of business.

capacity exists either within the in-house team or can be more efficiently found within the expertise of third party providers.

Post data centre rationalisation, the service management function will be further developed to take advantage of the consolidated data centre strategy. Support functions, both internal and third party, will become holistic from the previous segregated Operational and Non-Operational services. The management structure will become flatter with greater business focus. Common service management processes will operate across the organisation ensuring a uniform approach to such things as service levels, incident handling, problem management and change control. The revised IT operating model will have optimised resources and processes and utilise a mixed sourcing model to extract maximum efficiency savings.

For each business area, services will be delivered from the same team as projects such that there will be efficient utilisation of skills and resources. Management will work with the business areas to optimise the delivery of service issues such as problem fixes and minor enhancements with major implementations in a consolidated plan.

After embedding the revised operating model made possible by the data centre reconfiguration, we will continue to extract the maximum cost savings from the new model through:

- Regular market testing of systems and services in conjunction with contract reviews and commercial re-negotiations to ensure best value
- Use of best practice procurement processes led by the specialist central procurement team
- Further exploitation of our strategic systems and high performance ENW21CN network to maximise the value from previous investment
- Undertaking continuous service improvement exercises.

5.4 Sourcing

We anticipate that right-sizing, right-skilling, and right-sourcing our IT services will result in the most efficient outcome and that this will be achieved through approximately half of our IT&T business support cost base being supported by third party providers. This mixed sourcing strategy will ensure the best blend of in-house and third party resources to maximise advantages from economies of scale and retain in-house skills where they provide the greatest benefit using options such as Software as a Service (SaaS).

The majority of in-sourced costs will be incurred supporting specialist Operational IT activities and information security activities where there are known to be shortages in skills in the national and international resource markets or where, through innovation activities, we wish to maintain our position at the forefront of research.

The remaining in-sourced costs will almost exclusively be incurred supporting activities where IT industry experts, such as Gartner[4], advocate retaining in-house skills. These include areas such as strategy, architecture, assurance, commercial and contract management and key subject matter experts, particularly for front office systems such as work management, where competitive differentiation is crucial to success.

[4] Gartner is the world's leading information technology research and advisory company and has 5,600 associates, including 1,400 research analysts and consultants, and clients in 85 countries.

6. IT Security

The overall cyber-threat landscape is subtly changing. In the last ten years the main threat has been from relatively unskilled amateur attackers using widely available hacking tools. Typically, their aim was to deface web sites or to deny operations. Defences against these attacks include commercial anti-virus software which identifies and blocks known malware signatures and firewalls to block specific types of traffic.

The future is very hard to predict as attackers become better funded and trained. Cyber attackers are now using advanced techniques, often funded by criminal gangs or even nation states, to penetrate organisations in targeted attacks. These typically extract information such as financial plans or intellectual copyright material for commercial gain. The threat from terrorists is currently seen as low but increasing as examples of cyber-warfare with the goal of causing physical damage or widespread disruption are now being seen. Such targeted attacks are harder to defend against as attackers look to exploit known or new vulnerabilities in systems. However, the basic principles of defence in depth and a good understanding of valid network traffic will help mitigate the risk.

Given the increasing likelihood of cyber crime, an on-going programme of vulnerability and penetration testing of our estate identifies areas of weakness and mitigating actions are then taken. Dialogue with security vendors, special-interest groups and organisations such as the Centre for the Protection of National Infrastructure (CPNI) enables a good awareness of emerging technologies which can be assessed and deployed in a cost-effective manner in the future to mitigate identified risks.

For these reasons, investment in operational and non-operational IT security will be required throughout RIIO-ED1 to combat the ever-increasing threat from cyber criminals to an increasingly electronically-run organisation and distribution network.

We will maintain our compliance with ISO27001[5] and continue to follow the UK principles-driven regime, where core principles are agreed nationally and implemented by relevant parties.

Our active engagement in external forums such as E3C (Energy Emergencies Executive Committee) will remain, alongside our collaboration with other critical national infrastructure providers in order to share information on new threats and strategies for risk mitigation.

7. Green IT

Our Green IT strategy is simple in its goal of fully supporting our aims to both recognise our impact on the environment and manage our IT estate in as sustainable way as possible in the context of the UK's move towards a low carbon economy.

The most significant activity to support this Green IT strategy is the in-flight Data Centre Consolidation project which aims to consolidate the number of IT buildings in use today by moving from four existing facilities to two new facilities and to rationalise the computing infrastructure to improve both operational efficiency and long term sustainability. The intention behind the design of the new facilities, and the servers and environmental systems

[5] ISO 27001 is the international standard describing best practice for an Information Security Management System, often shorted to 'ISMS'.

used within them, is such that green technology and innovation will be used wherever possible to reduce energy consumption and long term carbon output.

The Data Centre project will also seek opportunities to make use of the government scheme for managing climate change. Where applicable, industry best practice is being applied throughout designs to optimise energy usage and emissions by implementing efficient solutions, such as ‘free cooling’ and ‘heat re-use’ in the IT Data Centre facilities. In addition, IT system virtualisation and commodity components that consume less power will be factored into the refresh of technology platforms.

Additional activities supporting our Green IT agenda include:

- Working to ensure the ethical and CSR credentials of potential IT suppliers are considered during IT procurement activities
- Ensuring the ethical disposal and recycling of IT equipment as it reaches end of life
- Implementing a managed print service and environmentally friendly printing policies such as default double sided printing
- Provision of video and tele-conferencing facilities to reduce travel between sites
- Development of an End User Computing strategy that allows for increased home working and opportunities for Bring Your Own Device (thus reducing the need to provide additional company owned devices to staff and contractors)
- Use of hosted shared services
- Increasing staff awareness of power usage effectiveness activities that can reduce overall power and cooling requirements for example through turning down brightness and turning up contrast, looking after laptop batteries through regularly draining completely and then fully re-charging, fully closing laptop lids when using an alternative monitor, and turning off Wifi and Bluetooth when not in use
- Improving asset life-cycle management techniques to sweat assets and extend refresh cycles
- Provision of hot desks rather than permanent workstations for staff and contractors who regularly work in multiple locations.

ANNEX 19: LOSSES STRATEGY

Electricity North West Limited
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Registered no: 2366949 (England)

Contents

1. Overview of our losses strategy

We have examined the potential to reduce network losses by the application of various alternative investment strategies during the RIIO-ED1 period and applying those strategies where there is a cost benefit to do so. We are also planning to maintain and expand our activities to investigate and minimise non-technical losses such as theft and continue work to establish a more reliable losses reporting baseline within RIIO_ED1.

The approach we have taken in applying Cost Benefit Analysis (CBA) to loss-driven investment options is based on the principles outlined in Ofgem's Strategy decision for the RIIO-ED1 electricity distribution price control dated March 2013 (Strategy Decision). For further details of our CBA analysis, please see Annex 3 – CBA.

2. RIIO-ED1 value of losses for CBA

2.1 Ofgem Guidance – Strategy Decision

The Ofgem CBA guidance in the "Business plans and proportionate treatment" document includes the following:

> 5.14. Where expenditures are justified using the reduction of electricity lost, our updated thinking is that DNOs should use the wholesale price of electricity less the EU Emissions Trading Scheme (ETS) cost of carbon (which is factored into the wholesale price) plus the carbon abatement value described below.
>
> 5.16. Our updated thinking is that assumptions for certain non-marketed parameters should be standardised. In relation to carbon abatement values, DNOs should use the DECC non-traded carbon values. Our decision is that DNOs should use the STPR for discounting carbon values. This approach is consistent with DECC and Green Book guidance.
>
> 5.9. We are minded to adopt a simple discounted cashflow approach for CBAs. The approach involves discounting all costs (including financing costs as calculated using the weighted average cost of capital (WACC)) and benefits (with the exception of safety benefits discussed in paragraph 5.14) at the social time preference discount rate (STPR). This involves the following two steps:
>
> 1. Convert capital costs into annual costs using the DNO's cost of capital
> 2. Use the STPR of 3.5 per cent in discounting all costs and benefits, as recommended by the HM Treasury Green Book.
>
> 5.22. Our latest thinking is that the period for the CBA should be a maximum of 45 years which represents the useful economic life of the asset.

2.2 Losses Valuation

The value of losses used in the CBA is £48.42/ MWh as provided by Ofgem.

3. Application of losses CBA to investment plan

We have examined two alternative intervention strategies for losses reduction.

3.1 Proactive intervention

This intervention strategy includes the intervention on existing assets purely driven by the losses CBA and the installation of new assets driven by the losses CBA analysis.

3.1.1 Replace plant or circuit equipment before end of life

Within this we have analysed circuit assets and transformer assets, but we have excluded switchgear and other plant as these assets have negligible losses in normal operation.

Circuits:

- Our analysis indicates that there is no justifiable benefit in replacing cables or overhead lines with larger section cables or conductors before the end of their normal operating life. We have not therefore included any such work in our investment plans.

Transformers:

- We have conducted a detailed CBA for loss reduction on ground-mounted distribution transformers. This indicates that there is strong positive benefit in replacing pre-1990 secondary network transformers with capacities over 750kVA. Prior to 1990 the core specification used was relatively high loss and proactive replacement with our present low loss specification would yield a positive benefit based on an average remaining residual life of 25 years.

  There are over 1,400 units matching these criteria on our network. Given the delivery issues associated with these additional outputs we have included some 689 additional units in our RIIO-ED1 plans. This number represents the greatest value in terms of loss savings that can be delivered in RIIO-ED1.

- Analysis of pole mounted transformers shows that there are no benefits in changing units before the end of their useful life.

- Our analysis indicates that for Grid and Primary transformers there is no benefit in replacement before the normal end of life.

3.1.2 Install additional assets such as capacitor banks to reduce losses

We have conducted a detailed analysis of the potential benefits of installing reactive power compensation equipment on our network to reduce losses. For details on our analysis see the Appendix.

The analysis has been based on three representative networks, Atherton BSP, Longsight BSP and a representative Electricity North West average model BSP group. For each group we have analysed the benefits of installing reactive compensation at each voltage level.

Based on the 25 year NPV Flat rate CBA analysis, the installation of reactive compensation is not justified at any voltage level. Our studies do indicate that the installation of reactive compensation equipment is most beneficial at LV; however the CBA is still adverse in the RIIO-ED1 period.

The effectiveness of the reactive compensation depends significantly on the load power factor. As the power factor approaches unity the effectiveness of reactive compensation diminishes. We have observed that the system power factor has been steadily improving over recent years and therefore the potential savings offered by reactive compensation are reducing. Our models show that it is likely that LCTs will reverse this trend during RIIO-ED1; however installation of additional equipment is unlikely to be justified on a losses CBA until RIIO-ED2 and only then under higher LCT penetration scenarios.

3.2 Opportunistic intervention

As part of our on-going connection, asset replacement and reinforcement activities, we will intervene to install or replace a significant number of assets in RIIO-ED1. We have carried out a detailed analysis of each asset class to determine if it would be justified to reduce or increase the scope of work; particularly purchase larger or smaller, lower or higher loss equipment driven by the marginal losses CBA.

Where justified we have included these marginal costs into our unit costs, that we have in turn used to price our submission.

Cables:

- Our analysis shows that for all voltage levels the installation of larger section cables is not justified by a losses-based CBA. However, when factors such as future load growth, stock holding costs and procurement volume discounts are factored in, it is beneficial to install 300mm^2 cable at HV and LV. We have therefore included these marginal costs within our unit costs.

Transformers:

- Our current policy is to install super low loss grid transformers that exceed the proposed EU Directive standard for 2020, the CBA detailed in the attached demonstrates that this is clearly justified delivering an NPV benefit of over £663,000 per unit. We have therefore built these into our unit costs.

- Our current policy is to install super low loss Primary Transformers that exceed the proposed EU Directive standard for 2020, the CBA detailed in the attached demonstrates that this is clearly justified delivering an NPV benefit of over £103,000 per unit. We have therefore built these into our unit costs.

- For ground mounted distribution transformers our analysis indicates that it is beneficial to replace all units scheduled for asset replacement with super low-loss units. There is however some uncertainty on the final cost of these units as the supply market is not yet mature. This would mean a change versus our current practice however the benefit over our existing low loss units is marginal and given the price uncertainty we have not built these super low loss units into our unit costs. In the event that the EU Directive is passed then replacements occurring after 2020 would be upgraded to the super low loss specification.

- For Pole Mounted Transformers our CBA analysis shows that our current low loss standard offers the best value for all sizes other than 200kVA. For 200kVA units the analysis shows that super low loss units offer better value.

4. Electricity Theft

We take the theft of electricity very seriously and have continued to invest in this area by operating a Revenue Protection Service for the majority of electricity suppliers in our Distribution Services Area. We also work closely with the police and other agencies in tackling electricity theft.

During 2013-14 we completed a review of the revenue protection team. As a result of this review we recruited additional personnel in 2013 in order to provide additional capability to suppliers who use our service and in tackling theft in conveyance, which is our responsibility to address. We are also introducing a new electronic communications system to speed up field to office information. This is scheduled to be rolled out during the Spring of 2014 to the improve the service we provide to suppliers and to tackle theft in conveyance.

Whilst we are seeing growth of detection of all types of electricity theft, we expect to maintain costs and income levels constant through reduced charges, as a result of the improvements to productivity from the new communication system and the benefits of the additional revenue protection inspectors. Theft in conveyance now represents 10% of the income we receive though we expect that this will increase over the RIIO-ED1 period.

4.1 Theft in Conveyance

In August 2011 we introduced a scheme, in accordance with Schedule 6 of the Electricity Act, to recover the value of electricity stolen as a consequence of Theft in Conveyance. We started to charge for Theft in Conveyance in 2012-13 however, we typically only recover a proportion of the amount billed.

The table below shows the income from this activity in comparison with that of the total income from revenue protection activities. These activities have been treated historically as Excluded Services (and in the future as Directly Remunerated Services and Services for Relevant Theft of Electricity from the Distribution System). We aim to cover off costs from the income received in line with the treatment within both of these special conditions.

Year	Transactional income	TiC income	Total revenue
2012/13	£732k	£46k	£778k
2013/14*	£808k	£91k	£899k

*Forecast outturn

The type of theft found in this area is in the region of:
60% - Unauthorised Connections
10% - Illegal re-connections
20% - Disconnected in error
10% - Connections process incomplete

When we identify theft in conveyance we seek to ensure that costs are recovered. The value that we seek to recover comprises:

1. The value of electricity taken
   a) The quantity of electricity taken by reference to the following factors:
      i) The consumption experience of the types of apparatus connected to the customer's installation;
      ii) The usage of customers with a similar pattern of use; and
      iii) The length of time that the connection is assessed to have been energised.
   b) The average price, derived from the three largest suppliers operating in our distribution service area during the period identified above; and
   c) The most suitable supply tariff based on the customer's type of connection.

2. Plus (as appropriate) the costs of:
   a) Disconnecting the connection;

b) Recovering the costs of any damage to our distribution system, meters, plant or equipment;
c) Recovering the costs of the investigation; and
d) Pursuing actions for electricity theft under the relevant legislation.

There are some instances where theft in conveyance has occurred where the industry can put right the data by undertaking a retrospective amendment to systems thereby ensuring that the supplier bills the customer. A simple example of this is where a site was disconnected in error. Once this is found, and dependent upon the length of time elapsed since erroneous disconnection, a simple system change can put the data right and the supplier is once again responsible for billing the customer. This work is undertaken by our revenue protection team but no invoices result as far as theft is concerned. This is nonetheless valuable work in that we ensure that the site has a registered supplier otherwise theft is occurring to the detriment of all.

Our charges are set at a rate that will recover the costs of the activities we undertake over plus the value of the electricity taken. Our charging statements can be found on our website at these links:

Schedule 6
Miscellaneous charges

The industry is currently looking at theft in conveyance issues under DCUSA which should result in a change to the recently approved (Electricity North West led) Revenue Protection Code of Practice.

It is not always possible to recover the theft in conveyance charges. For example, of 42 invoices raised for theft in conveyance, we achieved the following outcomes

	Number	Value
Invoices paid	22 (52%)	£100,175 (34%)
invoices not paid	20 (48%)	£192,279 (66%)

The outstanding debt is quite significant. We have been exploring other options to secure recovery. There is minimal appetite from the police to prosecute theft in conveyance, even when associated with other charges, such as cannabis cultivation.

We have recently commenced proceedings on a civil recovery basis in a number of cases where amounts owing are substantial. We have issued 'letters before action' in four 'test cases' to see how we progress down the civil route to recover such costs.

We are also taking advice on privately funded criminal proceedings in certain circumstances (where the case is likely to be economically viable and where a mechanism exists to recover costs). We are currently developing the necessary policies to support such proceedings but will await the outcome from the civil recovery test cases before confirming our approach in this area.

Our costs and revenues associated with theft in conveyance activities are currently reported as Excluded Service 5 ie we report theft in conveyance and revenue protection activities for third parties in combination in RRP and revenue RIGs.

From the start of 2014-15 we intend to capture the specific costs for the Theft in Conveyance activities making it easier to understand the true cost of this service and align with the necessary treatment of such a service under the new special condition.

4.2 Losses

During this financial year we have investigated seventy cases resulting in forty five confirmed instances of Theft in Conveyance. The losses identified are in the region of 2 GWh per annum. Some of these units are due to issues such as 'disconnected in error', and registration processes being incomplete. In some instances this results in a supplier being re-appointed and the data entering settlements (via a master registration agreement MAP04 process).

4.3 Further Work

We will continue to develop the Theft in Conveyance service to ensure that we have the processes and reporting in place in readiness for the new Licence obligation, and contribute to the development of the national revenue protection code of practice to cover off in more detail the activities associated with Theft in Conveyance.

5. Review and update of losses strategy within RIIO-ED1

The inclusion of losses within our CBA investment decision making will be a cornerstone of our investment assessment processes.

In our load and non-load programmes we have already included initiatives such as the proactive replacement of distribution transformers driven by losses benefits and we have allowed for the use of low-loss and where appropriate super low-loss transformers across the programme. During the period we will critically examine the forecast loading for each individual transformer to ensure the optimum type and size of unit is used via CBA.

In a number of cases the forecast demand may have increased or decreased and hence the unit size may have changed offering an opportunity for further reductions or the deployment of alternative techniques such as network meshing. Similarly we will critically evaluate cable sizes and conductor types to adequately account for capacitive and resistive losses on each cable installation. The embedding of CBA into intervention assessment and scheme design at the micro-level will ensure that each intervention is optimised from an overall CBA position including losses. This approach also ensures that as new technologies such as voltage optimisation and power electronics mature, they are appropriately included alongside DSR and more traditional techniques.

In our view the introduction of dynamic operating regimes for networks offers perhaps the greatest opportunity for losses reduction particularly in relation to DG. Our C2C: Capacity to Customers and Smart Street Tier 2 initiatives are exploring these techniques and we believe they will mature fully in the RIIO-ED1 period, and be enabled by our investments in network management systems and smart applications.

DG will present a particular challenge in the RIIO-ED1, not from the localised production of power which will act to reduce losses but rather from changes to upstream system power factor. The management of reactive power driven losses will become an increasing challenge for us as both DG and network meshing become more expansive, this is a future development area under our innovation allowances.

6. Approach to establish a reliable baseline of losses during RIIO-ED1

Work on establishing a reliable baseline position for network losses will not be possible without a much richer understanding of the load flows across our network particularly the Low Voltage networks. This understanding will be enabled by smart meter data and by the next generation of system modelling tools now being developed and trialled. We also consider that work such as WPD's LV network templates will help form a valuable platform upon which an understanding of the true behaviour of networks can be established.

A particular area of our current development work is the utilisation of time-series load-flow modelling in a new generation of modelling tools. Our Tier 1 project on LV network modelling is designed to develop this capability. Bringing these technologies to maturity will require cross sector collaboration and as chair of the Strategic Technology Programme we will lead this work through NIA funding.

The end-to-end rationalisation of losses solely through network and smart meter flows will be explored as part of our work, however we believe that the presence of unmetered load may frustrate its full deployment. It will however provide a valuable calibration technique for the time series modelling techniques.

7. Appendix

Atherton BSP Group

		Installation Costs	£ k	PFC Equipment designed to last 20-30 years
		200kVAr Switched Cap at LV	10	(with regular maintenance)
Peak Demand	99.5 MW	3MVAr Switched Cap at Primary	85	NB. Capacitors unlikely to last 20-30years
	22 MVAr	20MVAr Switched Cap at 33kV	320	These will need to be replaced as necessary
Load Factor	0.55			Therefore suggest the 25 year NPV rate is used.
Loss Load Factor	0.325	MWh Losses / year = MW Losses at Pk x L.L.F x 8760		This is the amount we can spend per MWh Saved
Switched Cap Adjustment Factor	0.75			

	kW Losses at Pk Demand (summated from IPSA)	Max MWh Losses / year	Max MWh Loss Saving pa vs System Normal	Actual MWh Loss Saving pa (based on Sw Cap)	Cost / MWh Saved pa	
System Normal - No Compensation	1580.86	4500.7	--	--	--	
200kVAr Compensation at LV Distribution Sub	1578.09	4492.8	7.9	5.9	**£1,691**	(increases to £1,744 for 5 x 200kVAr units installed)
3MVAr Compensation at Primary 11kV Bars	1564.2	4453.3	47.4	35.6	**£2,389**	PFC suffers from diminishing returns in terms of saving. See
20MVAr Compensation at BSP 33kV Bars	1541.27	4388.0	112.7	84.5	**£3,785**	

Notes
1 . Setup group in Composite Network model for Atherton comprising 132kV circuits, Atherton GTs, 33kV circuits and primary transfromers
2. Add typical HV radial feeder from one primary board (Bedford selected as typical primary). 2km of 300ACAS cable and Dist Tx + Load
3. From FLA establish MW, MVAr for Atheron BSP and scale loads in IPSA to give corrrect GT loadings
4. Establish Load Factor and Loss Load Factor from FLA
5. Add Capacitance at 33kV bars, at one primary board (Bedford selected as typical primary) and LV board of Dist Tx.
6. Run load flow with System Normal. i.e no Compensation switched in.
7. Take copy of IPSA Load Flow results and paste into worksheet. Summate Real Power Losses
8. Switch-in one capacitance at either LV, HV or 33kV and re-run load flow
9. Due to switched capacitance being in discrete steps, (typically 3 stage, 5 step in 1:2:2 Config), not all losses will be saved.
Therefore 'Switched Cap Adjustment Factor' introduced to account for this
10. PFC suffers from dimiinshing returns in terms of saving. i.e Each additional unit installed has less and less benefit as the power factor
approaches unity. Therefore these costs are the Minimum Cost / MWh Saved and will increase as more compensation is installed
11. Based on 25 year NPV Flat rate, installing compensation is not justified. Also given the downward trend of the Q/P ratio the requiremen
for compensation continues to diminish.

Lonsight BSP Group

		Installation Costs	£ k	PFC Equipment designed to last 20-30 years
		200kVAr Switched Cap at LV	10	(with regular maintenance)
Peak Demand	108	MW	3MVAr Switched Cap at Primary	85	NB. Capacitors unlikely to last 20-30years
	24	MVAr	20MVAr Switched Cap at 33kV	320	These will need to be replaced as necessary
Load Factor	0.61				Therefore suggest the 25 year NPV rate is used.
Loss Load Factor	0.39		MWh Losses / year = MW Losses at Pk x L.L.F x 8760		This is the amount we can spend per MWh Saved
Switched Cap Adjustment Factor	0.75				

	kW Losses at Pk Demand (summated from	Max MWh Losses / year	Max MWh Loss Saving pa vs System Normal	Actual MWh Loss Saving pa (based on Sw Cap)	Cost / MWh Saved pa
System Normal - No Compensation	1320.39	4511.0	--	--	--
200kVAr Compensation at LV Distribution Sub	1317.92	4502.5	8.4	6.3	£1,580
3MVAr Compensation at Primary 11kV Bars	1301.02	4444.8	66.2	49.6	£1,713
20MVAr Compensation at BSP 33kV Bars	1290.58	4409.1	101.8	76.4	£4,189

Notes

1 . Setup group in Composite Network model for Longsight comprising 132kV circuits, Longsight GTs, 33kV circuits and primary transfromers

2. Add typical HV radial feeder from one primary board (Levenshulme selected as typical primary). 2km of 300ACAS cable and Dist Tx + Load

3. From FLA establish MW, MVAr for Longsight BSP and scale loads in IPSA to give corrrect GT loadings

4. Establish Load Factor and Loss Load Factor from FLA

5. Add Capacitance at 33kV bars, at one primary board (Levenshulme selected as typical primary) and LV board of Dist Tx.

6. Run load flow with System Normal. i.e no Compensation switched in.

7. Take copy of IPSA Load Flow results and paste into worksheet. Summate Real Power Losses

8. Switch-in one capacitance at either LV, HV or 33kV and re-run load flow

9. Due to switched capacitance being in discrete steps, (typically 3 stage, 5 step in 1:2:2 Config), not all losses will be saved.
Therefore 'Switched Cap Adjustment Factor' introduced to account for this

10. PFC suffers from dimiinshing returns in terms of saving. i.e Each additional unit installed has less and less benefit as the power factor approaches unity. Therefore these costs are the Minimum Cost / MWh Saved and will increase as more compensation is installed

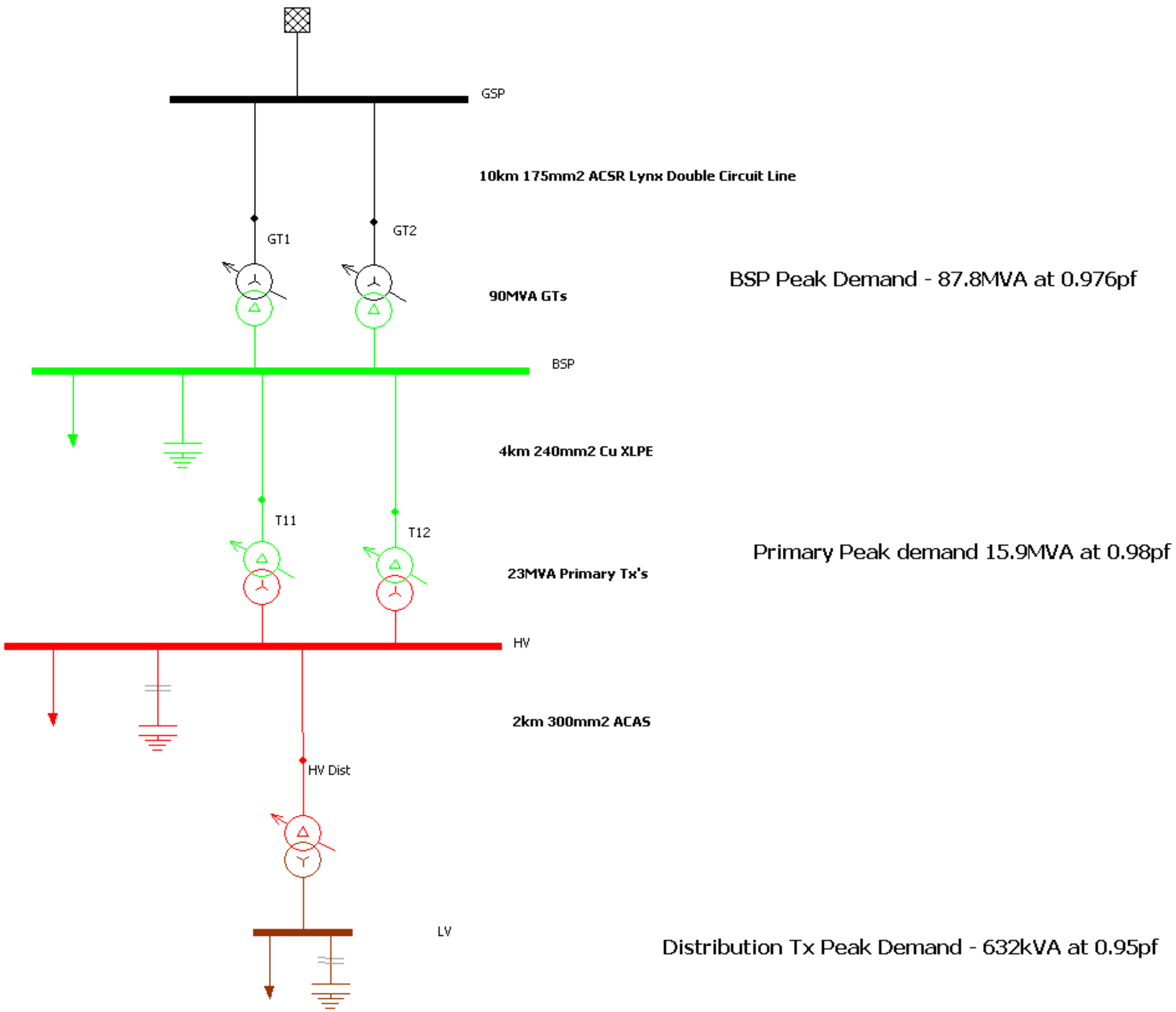
11. Based on 25 year NPV Flat rate, installing compensation is not justified. Also given the downward trend of the Q/P ratio the requirement for compensation continues to diminish.

Generic Model

		Installation Costs	£ k	PFC Equipment designed to last 20-30 years
Assumed Data		200kVAr Switched Cap at LV	10	(with regular maintenance)
Load Factor	0.55	3MVAr Switched Cap at Primary	85	NB. Capacitors unlikely to last 20-30years
		20MVAr Switched Cap at 33kV	320	These will need to be replaced as necessary
Loss Load Factor = a .FL + b.LF^2				Therefore suggest the 25 year NPV rate is used.
a	0.1			This is the amount we can spend per MWh Saved
b	0.9	**MWh Losses / year = MW Losses at Pk x L.L.F x 8760**		
Loss Load Factor	0.33			
Switched Cap Adjustment Factor	0.75			

	kW Losses at Pk Demand (summated from IPSA)	Max MWh Losses / year	Max MWh Loss Saving / year vs System Normal	Actual MWh Loss Saving pa (based on Sw Cap)	Cost / MWh Saved pa
System Normal - No Compensation	727.678	2086.0	--	--	--
200kVAr Compensation at LV Distribution Sub	725.427	2079.6	6.5	4.8	£2,066
3MVAr Compensation at Primary 11kV Bars	708.608	2031.4	54.7	41.0	£2,073
20MVAr Compensation at BSP 33kV Bars	674.105	1932.5	153.6	115.2	£2,778

Notes
1 . Create generic model in IPSA from comprising:- 132kV bar, typical 132kV circuits, typical BSP & Primary
2. Add typical HV radial feeder from primary board. 2km of 300ACAS cable and Dist Tx + Load
3. Add load blocks at 33kV and HV to simulate other newtork load.
4. Assume Load Factor and calculate Loss Load Factor from empirical formula above.
5. Add Capacitance at 33kV bar, at primary board and LV board of Dist Tx.
6. Run load flow with System Normal. i.e no Compensation switched in.
7. Take copy of IPSA Load Flow results and paste into worksheet. Summate Real Power Losses
8. Switch-in one capacitance at either LV, HV or 33kV and re-run load flow
9. Due to switched capacitance being in discrete steps, (typically 3 stage, 5 step in 1:2:2 Config), not all losses will be saved.
Therefore 'Switched Cap Adjustment Factor' introduced to account for this
10. PFC suffers from dimiinshing returns in terms of saving. i.e Each additional unit installed has less and less benefit as the power factor
approaches unity. Therefore these costs are the Minimum Cost / MWh Saved and will increase as more compensation is installed
11. Based on 25 year NPV Flat rate, installing compensation is not justified. Also given the downward trend of the Q/P ratio the requiremer
for compensation continues to diminish.


GSP
10km 175mm2 ACSR Lynx Double Circuit Line
GT1
GT2
90MVA GTs
BSP Peak Demand - 87.8MVA at 0.976pf
BSP
4km 240mm2 Cu XLPE
T11
T12
23MVA Primary Tx's
Primary Peak demand 15.9MVA at 0.98pf
HV
2km 300mm2 ACAS
HV Dist
LV
Distribution Tx Peak Demand - 632kVA at 0.95pf

ANNEX 20: ASSESSING THE IMPACT OF LOW CARBON TECHNOLOGIES ON GREAT BRITAIN’S ELECTRICITY DISTRIBUTION NETWORKS BY EATL

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CONFIDENTIAL REPORT

Prepared for: Energy Networks Association

Smart Grid Forum: Work Stream 3 – Phase 3

Assessing the impact of Low Carbon Technologies on Great Britain's electricity distribution networks

Analysis of Least Regrets Investments for RIIO-ED1 and supporting evidence

Issue 1.1

7th April 2013

Report No: 84170 - COMPLETE

Project No: 84170 - COMPLETE

Version	Date	Authors	Approved By	Comments
Draft 1.0	15/03/13	D Yellen, M Sprawson	Dave A Roberts 15/03/13	Report 3.6 - Preliminary results and analysis for discussion with WS3 Network Operator group
Draft 2.0	21/03/13	D Yellen	Dave A Roberts 21/03/13	Report 3.6 - Incorporating proposed changes from Mike Kay and John Scott
Final	25/03/13	D Yellen	Dave A Roberts 28/03/13	Report 3.6 - Final report approved by stakeholders
Issue 1.1	25/03/13	D Yellen	Dave A Roberts 07/04/13	Collation of all reports delivered under WS3 (3.1-3.6)

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- Chiltern Power
- Smarter Grid Solutions
- Grid Scientific

The project has taken input from a range of sources and the Network Operator project steering group:

- Energy Networks Association
- Electricity North West Limited
- UK Power Networks
- Northern Powergrid
- SP Energy Networks
- Western Power Distribution
- Scottish & Southern Energy Power Distribution
- National Grid

Executive Summary

This report provides an overview of the impact of the updates made to the Transform model during the period September 2012 to March 2013 and, in particular, the conclusions that can be drawn from the modelling in regard to 'Least Regret' investments and associated actions that might be considered for ED1, in the context of the forecast investments for ED2.

The modelling changes that have been incorporated are:

- Those proposed by Element Energy in their report Task 3.2
- Those proposed by Smarter Grid Solutions (SGS) in their report Task 3.4
- Those proposed by Grid Scientific (GS) in their report Task 3.5.
- Those proposed and accepted through Governance detailed in Task 3.1

The current version of the model has been peer reviewed by leading consultancies and the GB Network Operator community. All data and modifications to the model from this review have now been added and the model (version 3.2.0) has been re-run.

The specific focus of this work is to assess whether there are 'Least Regrets' investments or other actions that should be made in the RIIO-ED1[1] period in anticipation of achieving efficient deployments in ED2, noting the lead times involved.

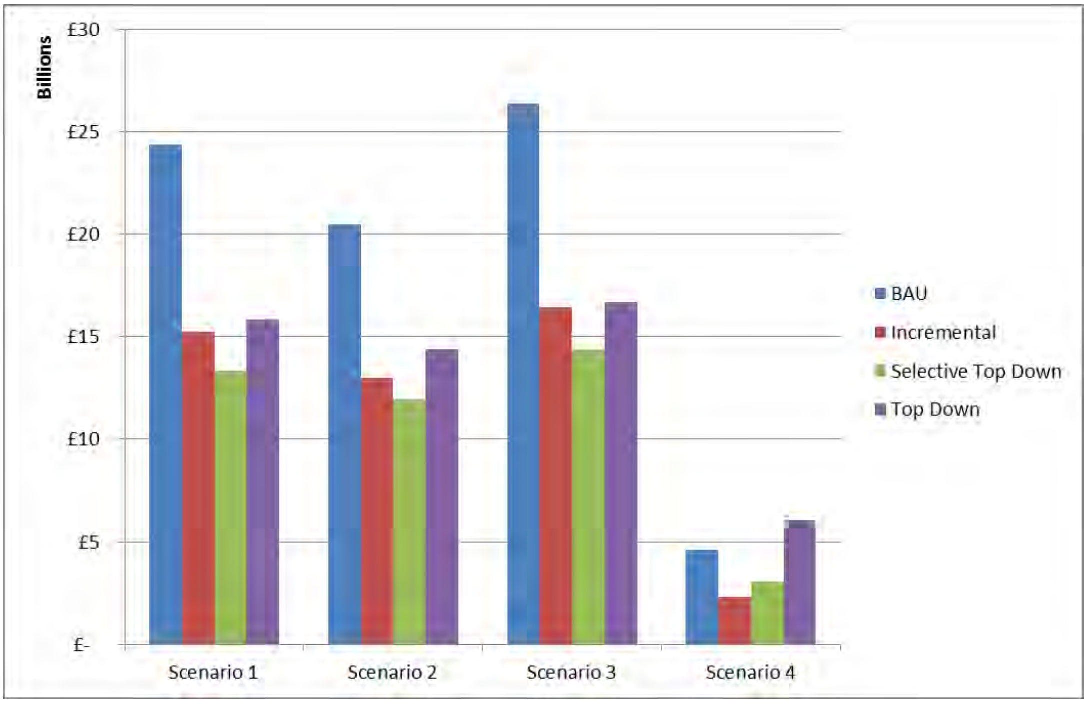
The analysis shows the following findings:

- The analysis continues to show a strong cost benefit in adopting a smart investment strategy over a purely conventional investment strategy for all the DECC scenarios considered to 2050; this benefit is of the order of 25-30% of total investment costs to 2050;
- The conclusions are not sensitive to the availability of any one individual smart solution; the model continues to show that a mix of smart and conventional solutions is likely to provide the optimum investment strategy for GB;
- The model can therefore be expected to provide helpful guidance for the estimated investment trajectory whilst not being prescriptive of specific smart solutions;
- Turning off the most highly selected smart solutions in the model only increases spend by 2% to 2050;
- The model now includes Tipping Point analysis that provides early warning to DNOs for the anticipated preparation timescales and the severity of likely business impacts of specific smart solutions on a distribution company's processes and systems;
- Incorporating the impact of Tipping Points on smart solutions, where the increasing scale of deployment offers the opportunity for procurement efficiencies, gives a further predicted investment benefit of around £1billion in Totex to 2050;
- An important conclusion from the revised model, that now includes closer analysis of enabler costs, is that a "Full" top down investment strategy no longer shows a financial benefit over an incremental investment strategy;

---

[1] RIIO – Revenue = Incentives + Innovations + Outputs and is the new style of energy Regulation introduced to Great Britain (GB) by Ofgem from 2013. The ED1 (Electricity Distribution one) period covers an eight year timescale from 1st April 2015 – 31st March 2023.

- However, further investment benefits can be obtained through implementing a “Selective” Top Down strategy where only the enablers required for the top-ranked solutions are deployed; this results in a benefit of up to £2billion in Scenario 3 (high electrification of heat and transport) compared to a smart incremental strategy;
- These benefits are not realised in Scenario 4 (where credit purchase is used to achieve de-carbonisation);
- Modelling of the Selective Top Down strategy suggests that the optimum timing for this will be early in ED2. Added to the fact that Selective Top Down introduces additional cost in scenario 4, it would appear sensible to wait until ED2 or the mid ED1 review point before committing to this strategy.
- The present value of total expenditure to 2050 predicted by the model for the four investment strategies is shown below:



In summary, the key messages from this work are as follows:

1. The Transform model has been significantly enhanced, in regard to both its analysis capabilities and the presentation of results to assist user interpretation;
2. A material cost-benefit continues to be indicated by adopting innovative ‘smart’ technologies in conjunction with traditional network investment;
3. While confirming the economic advantages of adopting smart solutions, the model is demonstrated to be broadly insensitive to specific solutions, which reinforces the message that it should not be used as a detailed ‘solution picker’, rather it should be used to inform strategic investment decisions;
4. A ‘Full’ Top Down strategy is no longer indicated as being beneficial now that the costs of enablers are better modelled, but the alternative ‘Selective’ Top Down

strategy is shown to be beneficial; commencing this strategy in ED2 appears to provide the best investment option at this stage; and

5. The deployment of innovative solutions in ED1, while of significantly lower scale than that forecast for ED2, is nevertheless expected to create material challenges for the DNOs; this report identifies the likely solutions appearing in ED1, their deployment numbers, which of these reach their Tipping Points, and the Tipping Points anticipated for ED2 that are likely to need preparatory action to be taken in ED1.

Contents

Lead Organisation: EA Technology
Report Number: 84170_1
Date: 11th March 2013
Issue: Final 1.0

11 Annex 6: Development of a licence area level feeder model

Lead Organisation(s): EA Technology / Element Energy
Report Number: 84170_2
Date: November 2012

12 Annex 7: Brief Summary of all other Changes made to the Model

Contained at the end of this report

1 Workstream 3 Timeline

This report presents the findings of the overall work program performed for the Smart Grid Forum Workstream 3 activity from July 2012 to March 2013. The top of the diagram below indicates the various documents produced throughout the WS3 activity while the middle describes the changes to the model that have been incorporated as scenario data and parameters have been updated, the bottom indicates model releases. The current version of the model, used for all analysis in this report, shown in red is the full release of Transform™[2] version 3.2.0.

The main body of this report presents the final report findings whilst the interim reports, detailing all changes made to the model over this period are presented in the Annexes. The annexes consist of:

- **Annex 1:** Smarter Grid Solutions' "Review of Enablers, Solutions and Top Down Modelling in Transform™"
- **Annex 2:** EA Technology's "Review of Enabler Mapping"
- **Annex 3**: Grid Scientific's "Tipping Point Analysis Report"
- **Annex 4:** EA Technology's "Review of Tipping Point Analysis"
- **Annex 5:** EA Technology's "Governance Period 1 Review Documentation"
- **Annex 6:** EA Technology/Element Energy's "Development of a licence area level feeder model"
- **Annex 7**: EA Technology's "Summary of all other Changes made to the model"

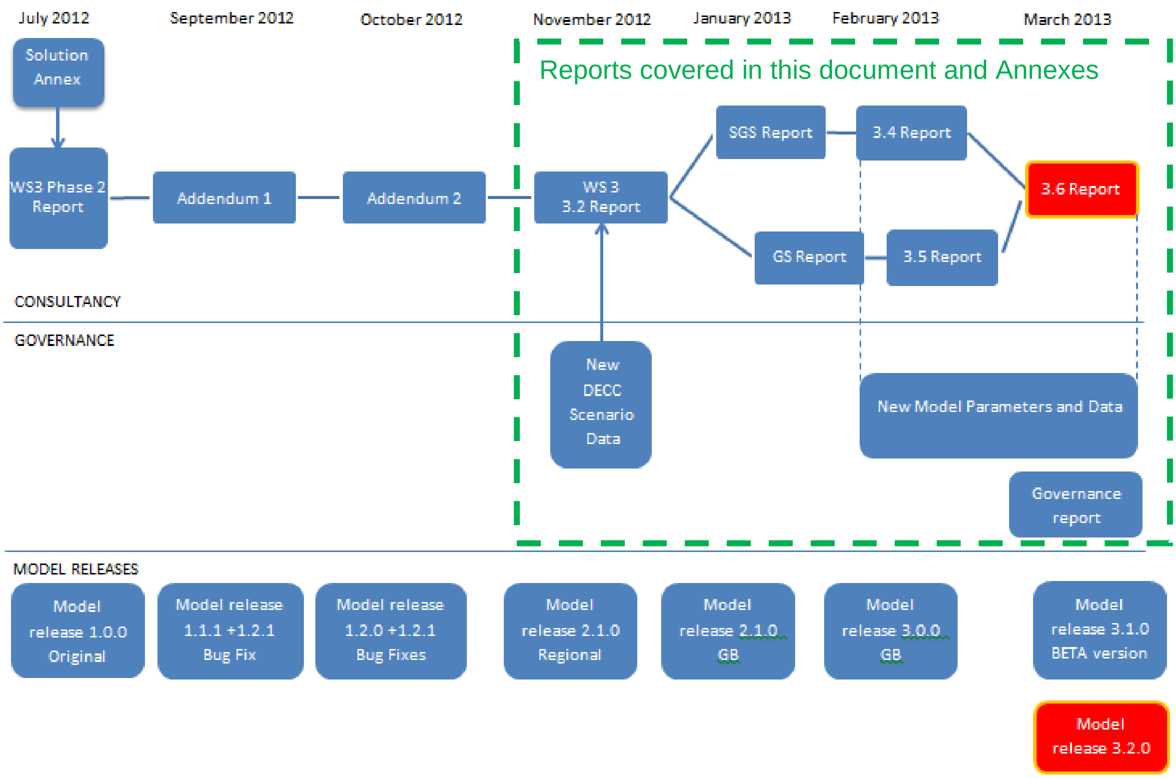


Figure 1 The Overall Smart Grid Forum Workstream 3 Phase 3 Timeline

[2] The Transform™ model is owned, developed and licensed by EA Technology. All GB DNOs, Ofgem and DECC have a royalty-free licence to use the software. Other users may access the model on a commercial basis.

2 Introduction

This report provides an overview of the impact of the changes made to the Transform™ model during the period September 2012 to March 2013. These changes include:

- Those proposed by Element Energy in their report Task 3.2;
- Those proposed by Smarter Grid Solutions (SGS) in their report Task 3.4;
- Those proposed by Grid Scientific (GS) in their report Task 3.5;
- Those proposed and accepted in Governance detailed in Task 3.1.

Each of these changes are reviewed in detail in their own separate reports, the broad outline of the detail is summarised below. Following this, the impact of these changes to the model is assessed and broad conclusions are drawn as to what early actions are predicted by the model.

The model used for testing all the assumptions is the most current version of Transform™ v3.2.0 issued to users on 13/3/13.

2.1 Overview of 3.2, Regionalisation of the Model

In task 3.2 the Transform™ model was modified to move from a national GB model to 14 discrete models covering each DNO licence area. In addition, the four scenarios for uptake of Low Carbon Technologies were modified to align with the four scenarios used by DECC in the fourth Carbon Budget (4CB).

The reader is encouraged to review report 3.2 for full information on the changes made.

2.2 Overview of 3.4, Model Review

In task 3.4 the inputs to the model were closely scrutinised by Smarter Grid Solutions Ltd (SGS). The output of this assessment was a number of enhancements to the model, all of which were reviewed and approved by SGS, EA Technology and the DNO community. The following developments to the model were included here:

- Improved data for Capex and Opex of solutions and enablers;
- Improved mapping of enablers to solutions;
- Addition of new enablers and solutions;
- Review of Optimism Bias with improved data;
- Improved mapping of solutions and enablers to cost curves.

The reader is encouraged to review report 3.4 for full information on the changes made.

2.3 Overview of 3.5, Tipping Point Analysis

In task 3.5 the impact of ‘Tipping Points’ was closely scrutinised by Grid Scientific Ltd (GS). The output of this assessment resulted in a number of enhancements to the model, all of which were reviewed and approved by GS, EA Technology and the DNO community. The following developments to the model have been included here:

- Application of Tipping Point Analysis to both solutions and enabling technologies
- Approach for the identification of Tipping Point thresholds for each solution and enabler
- Improved methodology for modelling cost curves and price changes post the Tipping Point of each solution;
- Improved mapping of enablers to solutions, including the ability to select enablers independently of specific solutions;
- Identification of timescales for preparation for Tipping Points (recognising the likely resources needed and the business challenges for network company's processes and systems);
- Review of all enablers and solutions regarding timescales for deployment, and specifically lead times for enabler deployment;;
- Improved reporting output from the model to assist user interpretation.

The reader is encouraged to review report 3.5 for full information on the changes made.

2.4 Overview of 3.1, Governance

In addition to tasks 3.4 and 3.5 the model was also subject to its first "Governance period". Under the governance mechanism, the following developments were made:

- Updated data from DECC on Distributed Generation and EV projections;
- Provision of four energy efficiency scenarios for a user to select;
- Further review and modification of enabler mapping.

In addition, a number of helpful longer-term changes to the model were proposed and these will be considered in due course for possible development funding.

The reader is encouraged to review report 3.1 for full information on the changes made.

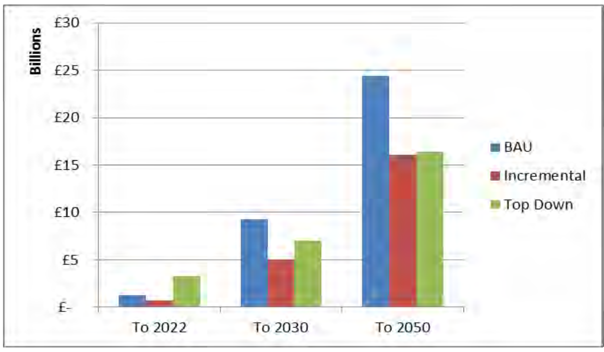
2.5 How we have arrived at the current 'baseline' model

The following sections outline the results obtained in a series of runs using the full v3.2.0 model. Firstly in section 3 we outline the results obtained through running the baseline model without Tipping Points. In section 4 we include Tipping Point analysis of cost curves and then address a number of scenarios utilising various strategies and draw out some of the sensitivities of the model in an attempt to identify Least Regrets investment options.

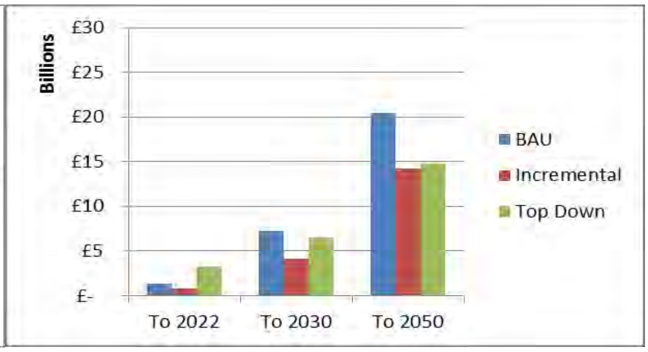
3 Model baseline results

3.1 Predicted investment by scenario and ED Period

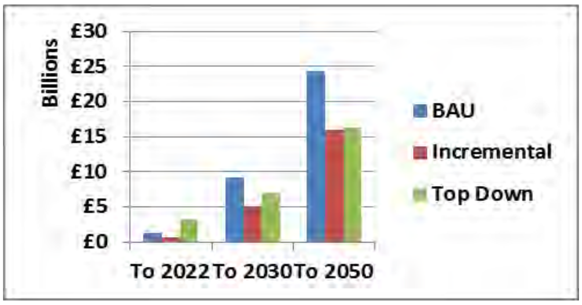
The following sets of graphs detail the predicted investment by scenario for the GB model 3.2.0, firstly split by RIIO ED periods, and then shown as a total investment cost to 2050. These results incorporate all changes to the model, but without treatment of Tipping Points.



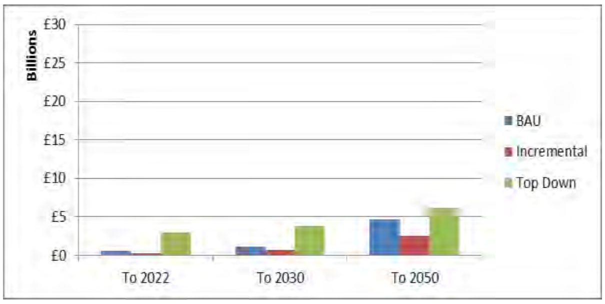
Scenario 1 (High abatement in low carbon heat)



Scenario 2 (High abatement in transport)



Scenario 3 (High electrification of heat and transport)



Scenario 4 (Credit purchase)

Figure 2 Predicted investment (Present Value [PV] of Totex[3]) by scenario to 2050

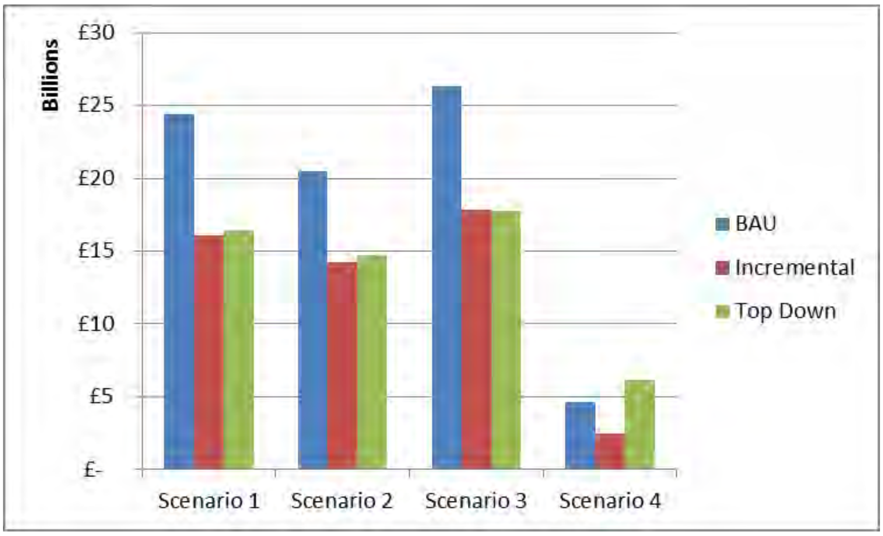


Figure 3 PV of Totex to 2050 of all scenarios by the three investment strategies

[3] Totex is the sum of capital and operating expenditure.

As can be seen, the Incremental smart investment strategy shows savings in all scenarios and in all time periods, compared with BAU investment only, through to 2050. This is particularly evident in the early years.

Compared with the previous (Phase 2) model results, the BAU costs have remained broadly similar whilst the smart incremental costs have reduced substantially (by nearly a quarter). However, unlike the previous analysis, the Top Down investment strategy is no longer indicating additional savings and, apart from Scenario 3, is more expensive than the smart incremental strategy. In section 4.1 we develop a 'Selective Top Down' strategy to address this new understanding of the full top down strategy. These results have been analysed following the model changes made, which confirms that this outcome for the Top Down approach can be attributed to the greater number of enablers (and therefore costs) now included in the model, making an initial investment in all enablers under a Top Down approach, more expensive on a PV Totex basis.

3.2 Solutions selected, by number deployed

Looking at the solutions and enablers being selected in the model we see the following as the top 10 in terms of number of times deployed in Scenario 3, smart incremental, to 2050.

Table 1 Top enablers/solutions selected by times deployed (note not by cost)

Solution/Enabler	Times Deployed	Year first deployed
Generator Providing Network Support - LV	598,573	2017
LV Circuit Monitoring (along feeder)	541,282	2015
Communications to and from devices - LAST MILE ONLY	463,580	2013
HV/LV Tx Monitoring	419,110	2017
LV feeder monitoring at distribution substation	395,700	2015
LV Ground mounted 11/LV Tx	253,174	2016
Permanent Meshing of Networks - LV Urban	211,875	2018
RTTR for HV/LV transformers	211,798	2022
DSR - DNO to residential	151,553	2022
Permanent Meshing of Networks - LV Sub-Urban	118,992	2020

The solutions and enablers all have different lifetimes so to give a sense check as to the total coverage of each solution/enabler on the network, these values need to be associated with their lifetimes (and the total number of feeders on the network) as shown below.

The table shows the effective coverage of each solution/enabler assuming the total number of feeders (EHV, HV and LV) remaining static at around 1,000,000 and dividing the time to 2050 by the assumed lifetime of each technology.

Table 2 Top enablers/solutions selected by network coverage

Solution/Enabler	Times Deployed	Lifetime (years)	Network Coverage to 2050
LV Circuit Monitoring (along feeder)	541,282	20	30%
LV Ground mounted 11/LV Tx	253,174	40	26%
Communications to and from devices - LAST MILE ONLY	463,580	20	26%
HV/LV Tx Monitoring	419,110	20	24%
LV feeder monitoring at distribution substation	395,700	20	22%
Permanent Meshing of Networks - LV Urban	211,875	45	22%
Permanent Meshing of Networks - LV Sub-Urban	118,992	45	12%
RTTR for HV/LV transformers	211,798	15	9%
Generator Providing Network Support - LV	598,573	5	8%
DSR - DNO to residential	151,553	5	2%

Readers should draw their own conclusions as to how realistic these predictions for deployment of solutions and enablers are for their particular network and innovation strategy; solutions/enablers that are not appropriate or are judged to be unsuitable can of course be “switched off” by a user when determining the best strategy for their context.

It is interesting to note the mix of smart and conventional solutions determined by the model. It is also informative to look at the timing of deployment of each of the smart and conventional solutions. The Graph below (again from Scenario 3 incremental analysis) shows the deployment of smart and conventional solutions out to 2050. This shows periodic peaks in activity and shows that deployment of smart solutions is predicted to diverge significantly and exceed conventional solution deployment, by cumulative numbers installed after 2030 and then rise rapidly higher from 2033.

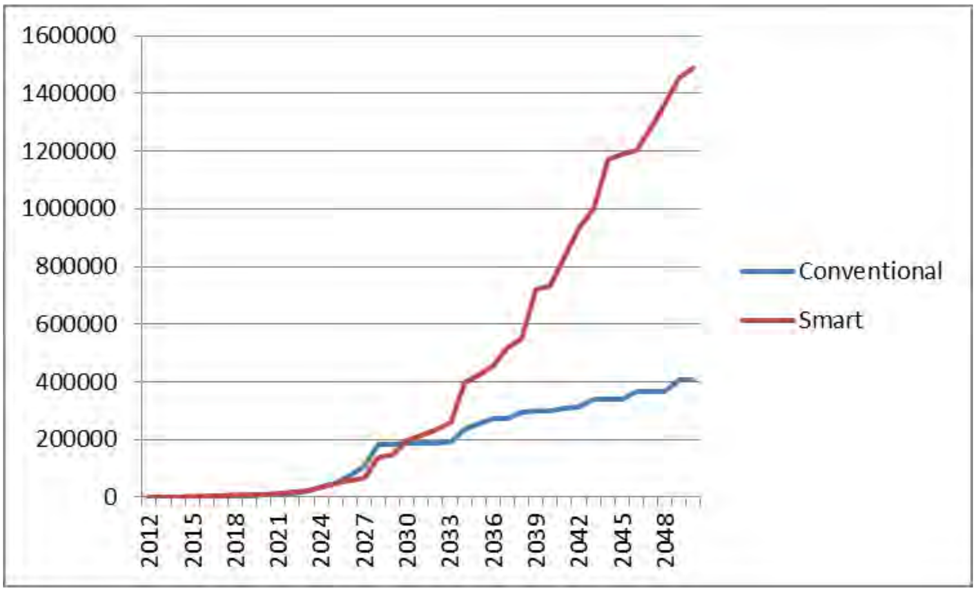


Figure 4 Cumulative Deployment of Smart and Conventional solutions to 2050 (Scenario 3 without tipping points)

Repeating the analysis with Tipping Point treatment of cost curves, shown on the following graphic, identifies that the dominance of smart technology solutions over conventional is brought forward to 2028.

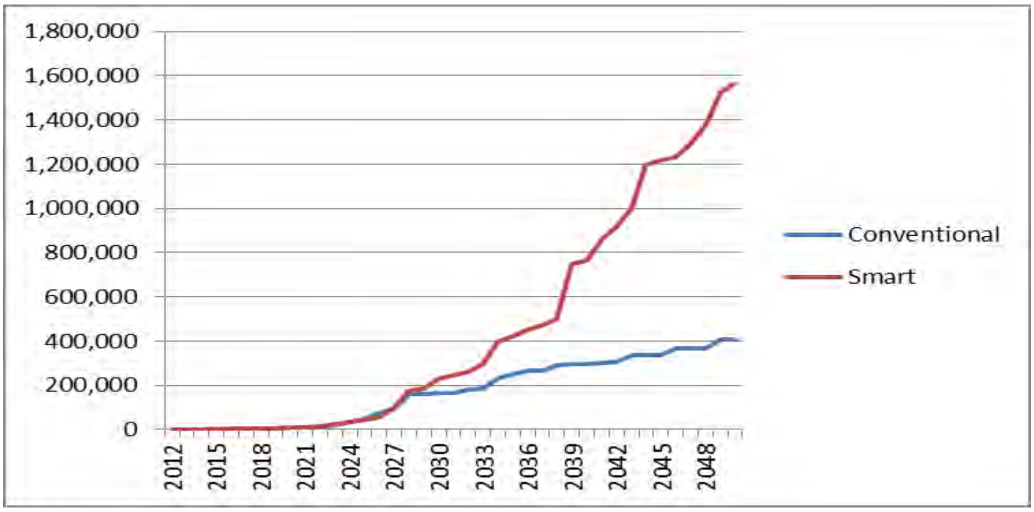


Figure 5 Cumulative Deployment of Smart and Conventional solutions to 2050 (high electrification of heat and transport, Scenario 3 with Tipping Point treatment to cost curves)

We will look at the impact of Tipping Points on the model in more detail in section 4 and we will see in section 4.3, this change in year of dominance of smart solutions is driven by a large number of solutions and enablers reaching their thresholds in 2025 to 2027 and therefore driving down the costs of these technologies.

3.3 Sensitivities of individual smart solutions

We noted in section 3.2 that certain smart solutions are frequently selected in the current runs of the model. To identify how sensitive the model is to the acceptability and success of these smart solutions we have run the model with each of these smart solutions individually "turned off". To achieve this, the availability of each solution in turn is set to 2051 in the model. We have done this individually for each of:

- Permanent Meshing Solutions
- Permanent and Temporary Meshing
- Generator Led response
- DSR

Giving the following outputs:

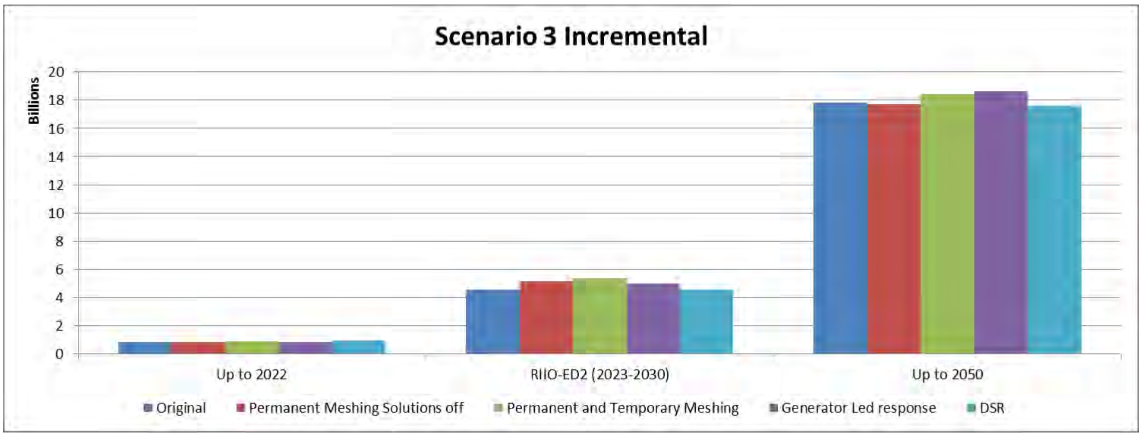


Figure 6 Effect of disabling individual smart solutions on Totex in scenario 3 incremental

This shows that the model outputs to 2050 for the smart incremental strategy are highly consistent and are not strongly dependent on one particular smart solution. In the shorter term, there is very little difference in spend in ED1 (2015-2022) but in ED2 (2023-2030) the extra spend is considerably higher and is highest when meshing is not allowed, (£5.3billion versus £4.6billion).

Where all meshing is not allowed and where generator led response is not allowed there is an overall increase in spend to 2050 of 3% and 4% respectively. Whereas where permanent meshing is not allowed and where DSR residential is not allowed there is actually a decrease in spend of 0.5% and 1% respectively. This decrease in spend is due to the timeframe selected for looking for optimum solutions. In the vanilla model we use a timeframe of 5 years and thus the model selects the optimum solutions for the next 5 years. This can be more expensive than the optimum investment to 2050. To sense check this analysis we can look at the same analysis in Scenario 4 (credit purchase) where lower numbers of electric vehicles and heat pumps are on the grid and hence there is a much lower rate of increase in electricity demand. In this scenario we see:

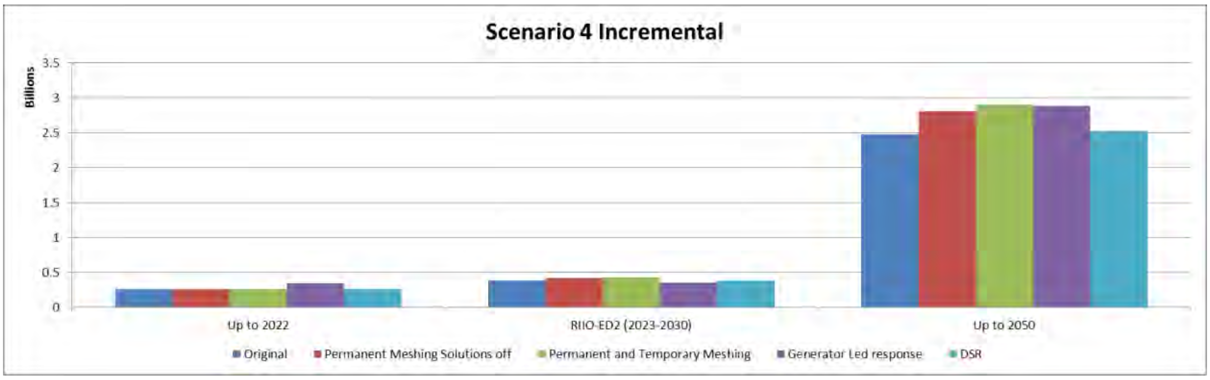


Figure 7 Effect of disabling individual smart solutions on Totex in scenario 4 incremental

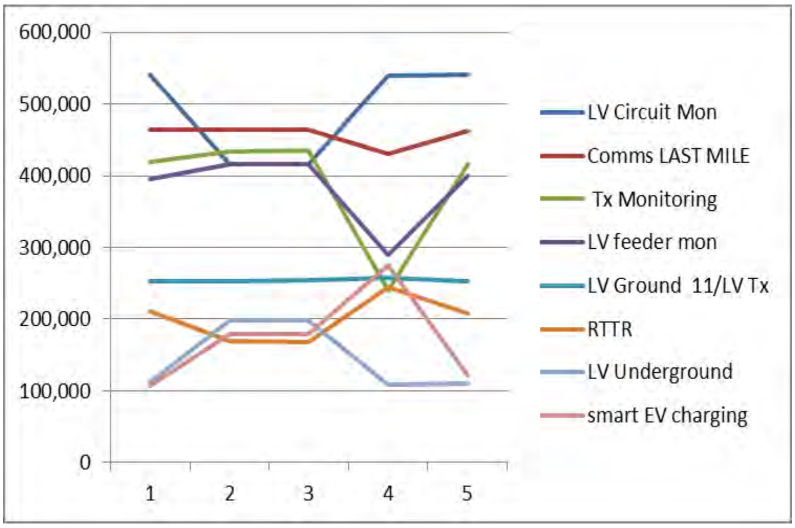
In this scenario we see that the lowest cost (just) is achieved with all smart solutions available. It is clear that the modelling results are relatively insensitive to the performance of individual smart solutions and as such the model provides a good guide to the overall cost of a “smart incremental” strategy and should therefore not be interpreted as providing a definitive menu for individual smart technology “winners”. In the table below we detail the impact on deployment of solutions of turning off individual smart solutions:

Table 3 Solutions and enablers deployed after turning off individual solutions

Solution/Enabler	Number Deployed				
	Original	No Permanent Meshing	No Meshing	No Generator Led response	No DSR
Generator Providing Network Support - LV	598,573	736,364	735,079	0	560,468
LV Circuit Monitoring (along feeder)	541,282	416,264	416,264	539,352	541,156
Communications to and from devices - LAST MILE	463,580	464,408	464,090	430,467	462,956
HV/LV Tx Monitoring	419,110	433,853	434,646	239,192	416,243
LV feeder monitoring at distribution substation	395,700	416,264	416,264	289,653	399,658
LV Ground mounted 11/LV Tx	253,174	253,174	254,621	257,407	253,174
Permanent Meshing of Networks - LV Urban	211,875	0	0	215,895	211,875
RTTR for HV/LV transformers	211,798	168,943	167,336	244,635	207,697
DSR - DNO to residential	151,553	308,012	308,012	209,591	0
Permanent Meshing of Networks - LV Sub-Urban	118,992	0	0	103,646	117,497
LV Underground network Split feeder	111,835	197,742	197,742	107,900	110,562
Local smart EV charging infrastructure	107,774	178,420	178,420	274,392	121,865

From the table above we can see that as expected, when certain solutions are turned off there are big rises in other solutions, for example when meshing is not allowed there is a big rise in DSR. In some circumstances, some solutions reduce. So we see that RTTR actually reduces when meshing is turned off. This is because the model chooses the optimum combination of solutions and in this case with no meshing, RTTR becomes a little less favoured as RTTR is often associated with meshing as a solution in the model.

Looking at these five different study cases we can see that some solutions and enablers remain constant over the five study cases shown, whilst others vary. The biggest change is made in option 4 (no generator side response) since this has an impact on a range of other technologies as shown below in the chart of numbers of deployments in each solution set:



Solution Sets Used:

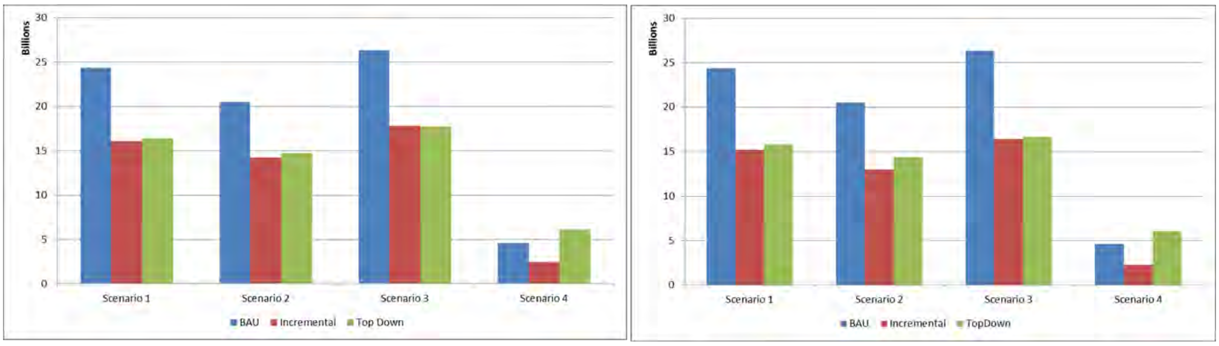
1. All solutions
2. No permanent meshing
3. No meshing
4. No generator led response
5. No DSR (Residential)

Figure 8 Number of deployments of key solutions across different study cases

4 The Model with Tipping Point Analysis

We now rerun the model using the Tipping Point analysis methodology provided by Grid Scientific. There remains more work to be done for cost curve analysis and to identify exact cost curve behaviour, to identify threshold values for each enabler and solutions, and to analyse further the business impact of a Tipping Point being reached,. It is hoped to gain more information on these through the next Governance period with input from BEAMA, DNOs and as field trial findings become known (eg from projects in Ofgem's Low Carbon Networks (LCN) Fund).

In the interim, we take the simplified approach that after its Tipping Point each solution moves to a "lower" cost curve, recognising the scale benefits that will be available from volume deployment. Thus cost curve 1 solutions move to cost curve 2 etc. Cost curve 5 solutions receive a one off reduction of 10%. Threshold values are maintained at the same values as used in WS3-Phase 2. This gives the following results (shown compared to without Tipping Points):



Without Tipping Points With Tipping Points

Figure 9 PV of Totex to 2050 of all scenarios with and without Tipping Point cost curves

This shows that a substantial further reduction in Totex spend is achieved by adding in the Tipping Point impact on cost curves. In scenario 3 this reduction takes Totex from around £17billion to around £16billion. We still observe no relative reduction in the costs of following a full Top Down strategy in any of the scenarios versus smart incremental.

4.1 Developing a "Selective Top Down" Strategy

The analysis to date has identified few savings for following a full top down versus a smart incremental strategy. This has led us to consider a new strategy, which we refer to as "Selective Top Down".

In this selective top down strategy, initial investment is made in only selected enablers, all other enablers are implemented in a smart incremental manner. Here we have considered three options based on combinations of the most commonly selected enablers, and solutions:

1. **All LV monitoring enablers** – the most commonly selected enablers
2. **All monitoring enablers** – a variant on 1
3. **All Comms and DSR Products** – these are associated with the most commonly selected solutions

From the analysis in Scenario 3 (high electrification of heat and transport) we can see that the best "Selective Top Down" strategy is the one where only the enablers required for the top solutions are deployed. This suggests a significant saving is achievable by investing in a selected number of smart enablers.

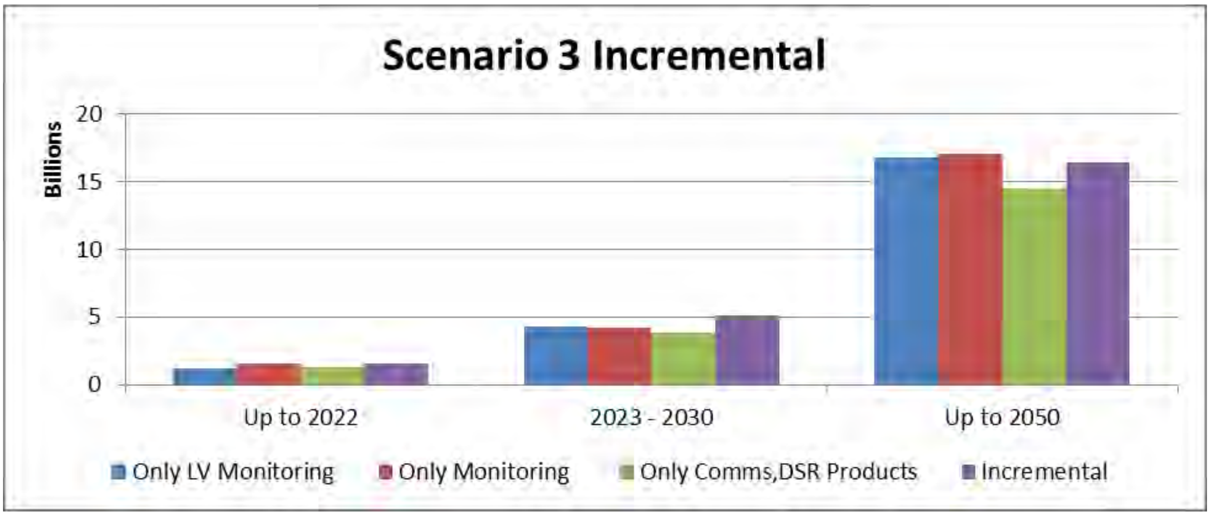


Figure 10 Overview of the three "Selective Top Down" investment strategies versus the original smart incremental strategy (as a comparison)

The chart above shows spend in ED1 (up to 2022), spend in ED2 (2023-2030) and total spend to 2050 for the three "selective top down" strategies investigated. In all three time periods, the most cost effective is the green "Only Comms, DSR Products" enabler strategy. In this strategy only comms and DSR enablers are purchased in a top down manner and all other enablers are purchased in a smart incremental manner – i.e as and when required.

4.2 Identifying the optimum years for Enabler investments

We have seen that the “Selective Top Down” Investment strategy can offer significant benefits over the Smart Incremental strategy and we now look at identifying the best timing for making this investment. We have assumed that a Selective Top Down strategy would take two years to roll out and, cognisant of the RIIO framework, we have looked at following the “Selective Top Down” Investment strategy in three different timeframes:

- 2019-2020 (Mid RIIO-ED1)
- 2020-2021 (Late RIIO-ED1)
- 2023-2024 (Early RIIO-ED2)

Following these investment timeframes gives the following outputs:

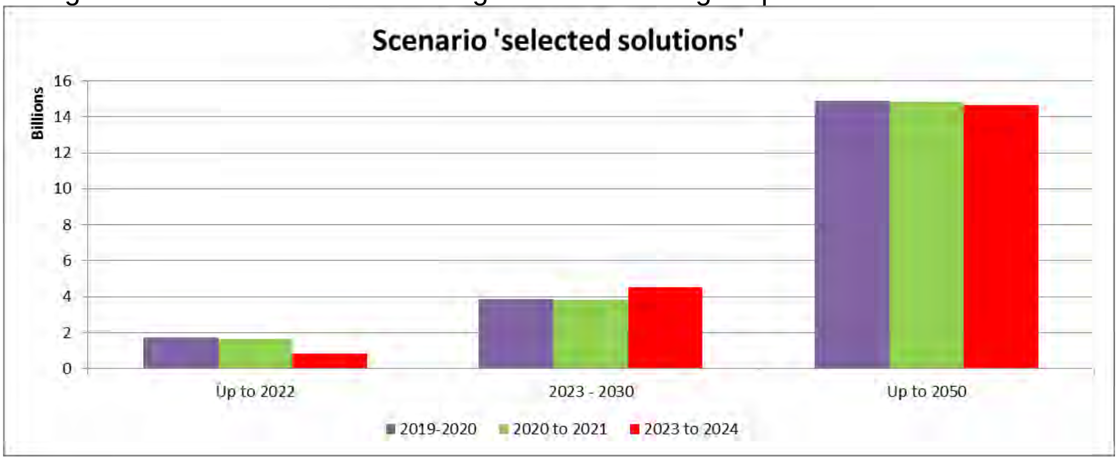


Figure 11 Comparison of Selective Top Down strategy investment in ED1 or early ED2

The graph above shows the total investment required for the three cases, where strategic top down investment is made in the selected enablers either in 2019-2020, 2020-2021 or 2023-2024. This shows only a small variation in total spend to 2050 with the overall most cost effective solution being to defer the strategic investment until the start of ED2 i.e in 2023 to 2024 (£14.6billion vs. £14.8billion).

Given the greater level of knowledge which will be available on both the performance of smart solutions and the market penetration of LCTs, the optimum strategy therefore appears to be to follow a smart incremental strategy in ED1 followed by a “Selective Top Down” strategy in ED2.

In addition it may be noted that in Scenarios 2 and 3 the saving made is smaller and in Scenario 4 (credit purchase), it is actually more costly to follow this strategy. It therefore appears most sensible to follow a smart incremental strategy through ED1 and assess this strategy either at a mid-point review of ED1 or in the RIIO-ED2 submissions when it can be expected that the level of knowledge of smart solutions and LCT penetration will be much clearer.

4.3 Summary of the impact of the investment strategies

During this analysis we have seen that the initial three strategies (BAU, Smart Incremental and Top Down) can usefully be supplemented with a further possible investment strategy, namely “Selective Top Down”. Further we have seen that this strategy is predicted to be most cost effective if implemented in early ED2. To summarise, it can be concluded that the optimum investment strategy is to follow a smart incremental strategy up to the end of ED1, then at the start of ED2 all Comms and DSR enablers are implemented in a strategic top down manner, all other enablers being purchased in a smart incremental manner. The chart below compares the outcome of these strategies for all four investment strategies.

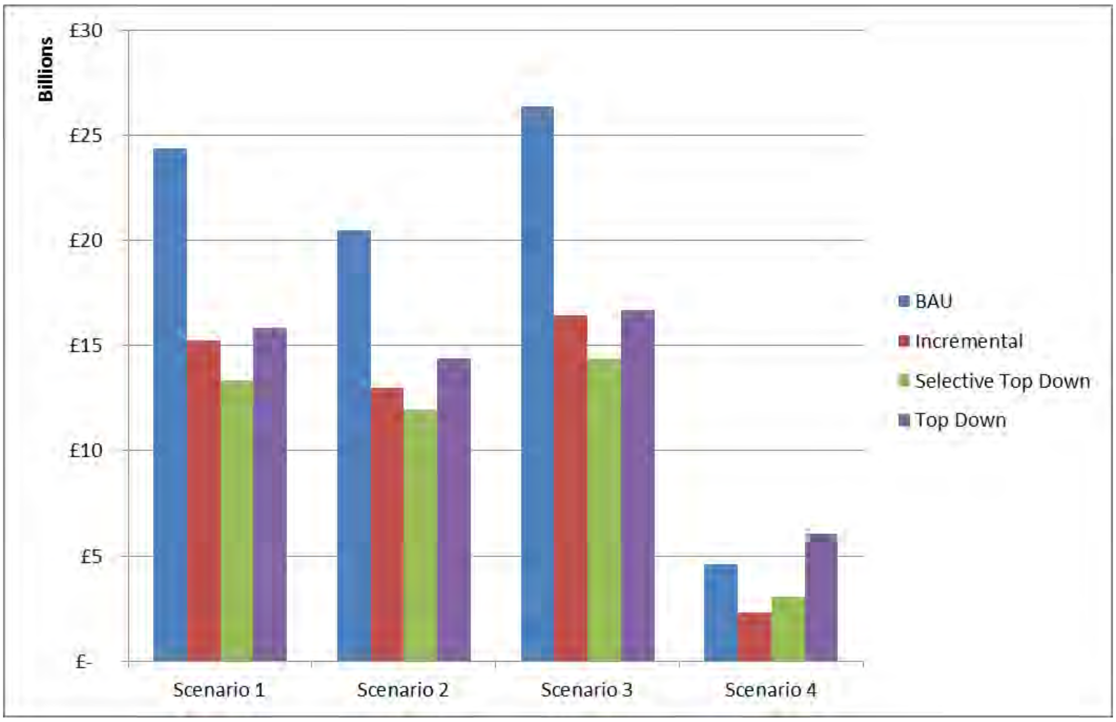


Figure 12 PV of Totex to 2050 of all scenarios by the four investment strategies

We now see that there are significant savings in scenarios 1-3 for following the selective top down strategy in early ED2. It is interesting to note that there are no savings in scenario 4 (credit purchase) where the proliferation of LCTs is low.

4.4 Major ED1 and ED2 Investments

It is informative to examine the individual smart solutions employed and their timescale for deployment. The Transform model now generates a Tipping Point report which, for scenario 3, gives the outputs shown below for the ED1 and ED2 periods. The trigger and tipping points are colour coded dependent on their likely impact on DNO business systems and processes, where 5 is the biggest impact. The business impact at the Tipping Point is defined as follows:

5: Very High - the solution will impact on processes and systems within the business, requiring substantial intervention, including management involvement
4: High - the solution will have impact that will require significant intervention, including management involvement
3: Medium - the solution will have impact that can be readily managed
2: Low - the process for introducing solution change at the tipping point will have some impact on the processes and systems within the business
1: Very Low - the process for introducing solution change at the tipping point will have limited impact on the processes and systems within the business

Note that the above is a measure of the impact of the solution on the processes and systems in a DNO's business, not a measure of the impact of the solution on solving network issues. A solution with low business impact can give a high value return (and vice versa).

The 'Tip' indicated below is the year when the solution (or enabler) reaches the assigned cumulative cost tipping point threshold, and the 'Trigger' indicates the number of years in advance of the tipping point that it is considered the DNO will need to start preparing its systems, processes and staff for the tipping point occurrence so that scale benefits can be secured and holistic systems integration achieved. If the Tipping Point for a solution is not addressed there is a highly adverse risk that solutions will be deployed in an ad hoc manner, without gaining the significant benefits of standardisation and thought-through integration with company business systems. Benefits of addressing the Tipping Point (described as creating an Integrating Framework) will be evident in areas such as: procurement, stores holdings, skills and training, international standards alignment and open systems, future-proofing, and data management that brings benefit to the business and its customers most widely.

The formats shown in the following two tables are now included as a report in the Transform model.

Table 4 Smart solutions deployed in ED1

Solution Name	2015	2016	2017	2018	2019	2020	2021	2022
Permanent Meshing - LV Urban		Trigger	----	Tip				
Permanent Meshing - LV Sub-Urban				Trigger	----	Tip		
RTTR for HV/LV transformers								Trigger
Switched capacitors – LV		Trigger	Tip					
Communications - LAST MILE ONLY	Trigger	----	Tip					
DSR - Products remotely control loads					Trigger	----	----	Tip

It can be observed that five smart solutions reach their tipping point during ED1; and six trigger points are identified including one for a smart solution that tips in ED2. There are no high business-impact solutions (red) reaching their tipping point during ED1 but two are moderately high impact (yellow). This indicates a reasonably material set of new challenges for DNO's to address in ED1. This is further addressed in the analysis below.

Table 5 Smart solutions deployed in ED2

Solution Name	2023	2024	2025	2026	2027	2028	2029	2030
DSR - DNO to residential					Trigger	----	----	Tip
Generator Network Support - HV					Trigger	----	Tip	
Generator Network Support - LV	Trigger	----	Tip					
RTTR for EHV/HV transformers					Trigger	----	Tip	
RTTR for HV Overhead Lines	Trigger	----	Tip					
RTTR for HV Underground Cables					Trigger	----	Tip	
RTTR for HV/LV transformers	----	Tip						
Temporary Meshing - HV	Trigger	----	Tip					
Advanced control systems - HV	Trigger	----	Tip					
EHV Circuit Monitoring		Trigger	----	Tip				
HV/LV Tx Monitoring			Trigger	----	Tip			
LV Circuit Monitoring (along feeder)	Trigger	----	Tip					
RMUs Fitted with Actuators	Trigger	----	Tip					
Dynamic Network Protection 11kV	----	Tip						

It can be observed that in ED2 fourteen solutions reach their tipping points and there is a range of business challenges represented here including one 'red' and six 'yellow' categories. This indicates a potentially highly challenging context in ED2. Further insight can be gained if we also examine the projected capex outlay by regulatory period and the year of first deployment for each of these solutions. Note that comparing the first year of deployment and the tipping point year provides an indication of the rate of take-up for each solution. Note also the co-incident years of first deployment, indicating the potential for high workload peaks in ED1. See the table below:

Table 6 Capex and first deployment for smart solutions in ED1 and ED2

Smart Solution	Year First Deployed	Tipping Point Year	Ramping Period	Capex ED1 £M	Capex ED2 £M
Communications - LAST MILE ONLY	2013	2017	4	17	135
Switched capacitors - LV	2015	2017	2	34	0
LV Circuit Monitoring (along feeder)	2015	2025	10	8	82
Generator Network Support - LV	2017	2025	8	2	129
HV/LV Tx Monitoring	2017	2027	10	1	32
Permanent Meshing - LV Urban	2018	2018	0	38	99
RTTR for HV Overhead Lines	2019	2025	6	3.4	61
EHV Circuit Monitoring	2019	2026	7	1.6	27.5
Permanent Meshing - LV Sub-Urban	2020	2020	0	69	750
RTTR for HV/LV transformers	2022	2024	2	2.5	87
DSR - Products remotely control loads	2022	2022	0	33	202
DSR - DNO to residential	2022	2030	8	2	17
Generator Network Support - HV	2022	2029	7	1.4	29
Temporary Meshing - HV	2022	2025	3	4	42
Advanced control systems - HV	2022	2025	3	1	12.5
RMUs Fitted with Actuators	2022	2025	3	2	21
Dynamic Network Protection 11kV	2022	2024	2	3	31
RTTR for EHV/HV transformers	2027	2029	2	0	61
RTTR for HV Underground Cables	2029	2029	0	0	14

It is important to note that almost all the smart solutions deployed in ED1 and ED2 are shown to have their first deployment during ED1. This suggests that ED1 will be a period of significant learning for the DNOs for deployment of new smart technologies. Also, a very large number are projected to be deployed in 2022 which may be too late for learning from operational experience to be capture in ED2 business plan submissions.

It should be further noted that some technologies reach their tipping point very quickly following deployment (and in some cases in their first year of deployment) whilst others take many years to reach their tipping points. This is shown in the table as the ramping period. Understanding the speed of this cumulative deployment may help the DNOs further develop their plans for handling the build up of resources and manpower for deploying these technologies.

Finally it is clear that there are some ambitious assumptions surrounding these technologies and the figure for investment in permanent meshing in ED2 is particularly challenging. It was demonstrated in section 3.3 that the projections for spend are not dependent on individual technologies and the list above should be treated as an indication of possible solutions to consider rather than as a prescribed menu of solutions.

4.5 Cost implications for ED1 and beyond

The chart below shows the non-discounted cumulative Totex spend in each ED period looked at firstly in the boundary conditions, that is to say highest electrification (Scenario 3) together with the least attractive spending strategy (BAU) versus lowest electrification (scenario 4) with best spending strategy (smart incremental for scenario 4).

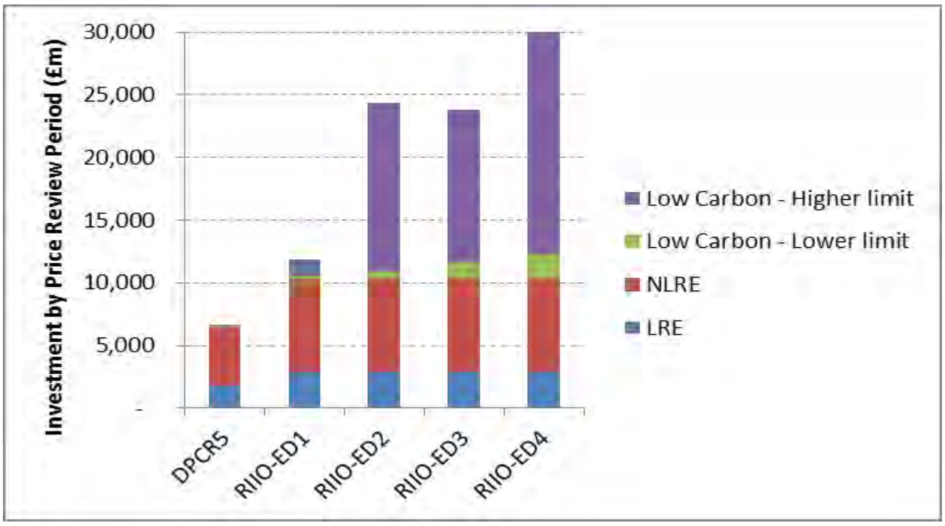


Figure 13 Non discounted cumulative Totex for the best and least attractive spend strategies for the next four RIIO periods[4]

This shows a very significant range in possible spend profiles for ED2. It is perhaps unrealistic to compare these two extremes, so below we look at the same chart but compare

[4] **Load related expenditure** (LRE) – investment driven by changes in demand, i.e. that in response to new loads or generation being connected to parts of the network (connections expenditure) and investment associated with general reinforcement. LRE was £1.8bn in DPCR5. **Non-load related expenditure** (NLRE) – other network investment that is disassociated with load. The dominant area of investment in this category is asset replacement (76% of the NLRE for DPCR5). NLRE was £4.6bn for DPCR5. **LRE and NLRE** have been simply scaled by 8yrs/5yrs to correlate to the longer Price Control Periods for RIIO in this illustration.

the best spending strategy in the highest and lowest electrification scenarios. So we compare Scenario 3 Selective Top Down to Scenario 4 smart incremental:

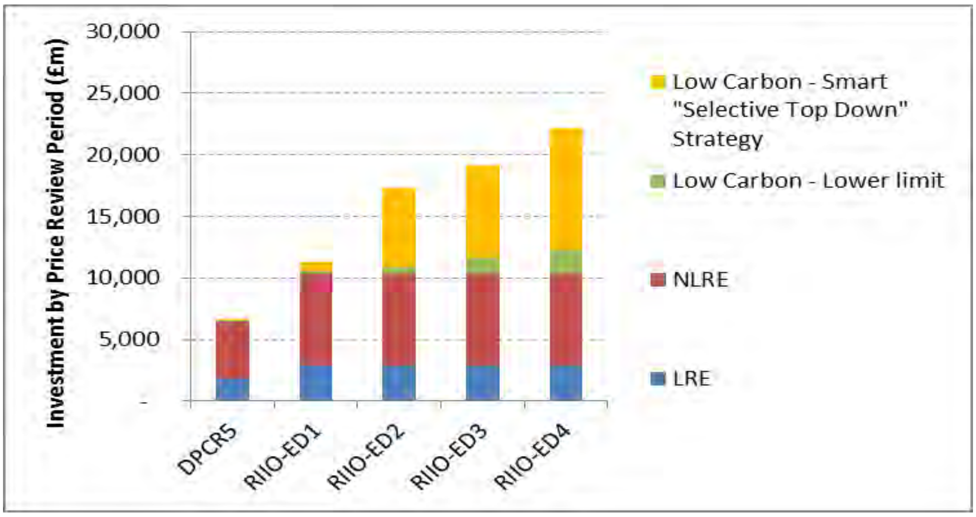


Figure 14 Non discounted cumulative Totex for best possible spend (using the two most extreme scenarios)

We still see a very large differential in spend in ED2 and beyond. This provides some insight to the range in possible investment required dependent upon the uptake rate of LCT's. This demonstrates the level of uncertainty that must be addressed and the sensitivity to the current level of understanding of future use of LCTs.

4.6 Comparison to WS3-Phase 1

In the first phase of WS3, the report "Developing Networks for Low Carbon" was released (October 2011). This identified a number of potential investments "ahead of need" and it is interesting to look at whether the current analysis provides support for these. The table below is from p 61 of the above report:

	Initial Thoughts – Strategic Investment Ahead of Need
1.	Discontinue LV tapering; note that loss-savings can be expected; however, new network infrastructure may be provided in a competitive environment, so additional costs would probably have to be socialised through DUoS (not paid for by a developer)
2.	Make provision for rich communications links (e.g. optic fibre)
3.	Revise LV planning methodologies including ADMD assumptions, especially in the interim period towards 2020 while smart meter data is incomplete; consider the planning assumptions now needed for DG and voltage rise; consider the fundamental change of demand profiles arising from HP and EV loads
4.	Enlarge the layout/footprint of LV substations for additional equipment, including storage, intelligent controls, provision for sensors; however, note here the pressure for minimum footprints (and the fact that new substation provision for new developments is subject to competition)
5.	Reconsider pole-mounted substations and their adaptation for smart facilities (e.g. land space at the foot of pole mounted substations)
6.	Reconsider the specification of package substations
7.	Full review of P2/6 methodology including intentional islanding (off-grid operation) and system operating standards
8.	Revise network design policies including P2/6 (incorporate DR, DG, Storage, and Resilience)
9.	Note the importance here of resolving standardisation issues (see the proposed next steps action)
10.	Commence review and development of the architecture evolution for network company Intelligent and Dynamic System Platforms to ensure that they enable the future applications of Smart Grid 1.0 and Smart Grid 2.0 (see next steps action)

Figure 15 Initial Strategic Investments proposed in the Phase 1 report

Overall, the model outputs give good support for the early actions identified in phase 1, although much of this work will be preparatory for a larger effort in ED2 dependent on proliferation of LCTs meeting the data suggested in DECC Scenarios 1-3, rather than the lower numbers in Scenario 4.

Specifically the recent analysis gives support to most of the issues raised in points 1-4 and 6-8 of the table. However it is important to emphasise that, for instance, the current lack of support for electricity storage in the Transform™ outputs does not mean that this is a poor technology and research should stop. It simply reflects that, using the cost assumptions in our model, more work needs to be done to make this technology cost competitive.

5 Conclusions

This report has reviewed the impact of the changes made to the GB Transform™ model during the period September 2012 to March 2013.

These changes have resulted in the following outputs from the model:

- The analysis continues to show a strong cost benefit in adopting a smart investment strategy over a purely conventional investment strategy for all the DECC scenarios considered to 2050; this benefit is of the order of 25-30% of total investment costs to 2050;
- The conclusions are not sensitive to the availability of any one individual smart solution; the model continues to show that a mix of smart and conventional solutions is likely to provide the optimum investment strategy for GB;
- The model can therefore be expected to provide helpful guidance for the estimated investment trajectory whilst not being prescriptive of specific smart solutions;
- Turning off the most highly selected smart solutions in the model only increases spend by 2% to 2050;
- The model now includes Tipping Point analysis that provides early warning to DNOs for the anticipated preparation timescales and the severity of likely business impacts of specific smart solutions on a distribution company’s processes and systems;
- Incorporating the impact of Tipping Points on smart solutions, where the increasing scale of deployment offers the opportunity for procurement efficiencies, gives a further predicted investment benefit of around £1billion in Totex to 2050;
- An important conclusion from the revised model, that now includes closer analysis of enabler costs, is that a “Full” top down investment strategy no longer shows a financial benefit over an incremental investment strategy;
- However, further investment benefits can be obtained through implementing a “Selective” Top Down strategy where only the enablers required for the top-ranked solutions are deployed; this results in a benefit of up to £2billion in Scenario 3 (high electrification of heat and transport) compared to a smart incremental strategy;
- These benefits are not realised in Scenario 4 (where credit purchase is used to achieve de-carbonisation);
- Modelling of the Selective Top Down strategy suggests that the optimum timing for this will be early in ED2. Added to the fact that Selective Top Down introduces additional cost in scenario 4, it would appear sensible to wait until ED2 or the mid ED1 review point before committing to this strategy.

In summary, the key messages from this work are as follows:

1. The Transform model has been significantly enhanced, in regard to both its analysis capabilities and the presentation of results to assist user interpretation;
2. A material cost-benefit continues to be indicated by adopting innovative ‘smart’ technologies in conjunction with traditional network investment;

3. While confirming the economic advantages of adopting smart solutions, the model is demonstrated to be broadly insensitive to specific solutions, which reinforces the message that it should not be used as a detailed ‘solution picker’, rather it should be used to inform strategic investment decisions;

4. A ‘Full’ Top Down strategy is no longer indicated as being beneficial now that the costs of enablers are better modelled, but the alternative ‘Selective’ Top Down strategy is shown to be beneficial; commencing this strategy in ED2 appears to provide the best investment option at this stage; and

5. The deployment of innovative solutions in ED1, while of significantly lower scale than that forecast for ED2, is nevertheless expected to create material challenges for the DNOs; this report identifies the likely solutions appearing in ED1, their deployment numbers, which of these reach their Tipping Points, and the Tipping Points anticipated for ED2 that are likely to need preparatory action to be taken in ED1.

6 Annex 1: Review of Enablers, Solutions and Top-Down Modelling in TRANSFORM

Lead Organisation: Smarter Grid Solutions

Report Number: 200109-05C

Date: 13th February 2013

Issue: Version C (Final Issue)

7 Annex 2: Review of Enabler Mapping

Lead Organisation: EA Technology

Report Number: 84170_3.4

Date: 11th March 2013

Issue: Final 1.0

8 Annex 3: Tipping Point Analysis Report

Lead Organisation: Grid Scientific

Report Number: GSWS3.3DOC06

Date: 13th February 2013

Issue: 1.0 Issue

9 Annex 4: Review of Tipping Point Analysis

Lead Organisation: EA Technology

Report Number: 84170_3.5

Date: 11th March 2013

Issue: Final 1.0

10 Annex 5: Governance Period 1 Review Documentation

Lead Organisation: EA Technology

Report Number: 84170_1

Date: 11th March 2013

Issue: Final 1.0

11 Annex 6: Development of a licence area level feeder model

Lead Organisation(s): EA Technology / Element Energy

Report Number: 84170_2

Date: November 2012

NB. This report also includes a 5 page Addendum “Modifications to the WS3 Phase 2 methodology and assumptions”, issued December 2012

12 Annex 7: Brief Summary of all other Changes made to the Model

This document captures the changes that have been made to Transform™ since the Phase 2 release in July 2012. In all cases the scale of the change has been recorded by showing whether it increases the costs predicted by the model (represented by one, two or three ↑ depending on the magnitude of the increase), decreases the costs (again shown by one, two or three ↓ depending on scale of change) or if it makes no change to the model output costs (**━**).

The changes to the model are grouped in the following three sections:

1. Changes made under 'Phase 3' activity (tasks 3.2, 3.4 and 3.5)
2. Changes made under governance (task 3.1)
3. Changes made to fix elements of the model that were found to contain bugs

The following tables summarise these changes.

Table 7 Changes made under tasks 3.2, 3.4 and 3.5

Change	Effect
Solution costs refined through Task 3.4 (Opex and Capex)	↑↑↑
Optimism bias revised down	↓
Apportionment of conventional solutions across feeders revised (e.g. pole mounted transformers)	↑
Solution/Enabler Mapping enhanced	↑
Tipping points now available for enablers as well as solutions	━
Tipping points now allow solutions to be moved to 2 different cost curves and be subjected to 2 different multipliers.	━
A summarising tipping point report is integrated into the model	━
Feeder loads have been regionalised into the fourteen licence areas	━
Spreadsheet created for generating regionalised scenarios automatically from revised scenario data	━
Average GB feeder loads very slightly adjusted as a result of detailed analysis while conducting regionalisation	↔
Added capability to make strategic investments effectively removing certain enablers and directly injecting cost to the model.	━
Added capability to set time at which enablers start/stop being charged for.	━
Increased substation intervention threshold in GB model for HV4 to 75% in line with slightly increased loads from re-regionalising data	↓
Adjusted structure for generating top down costs	━
Adjusted the mechanism used to calculate the required deployment of enabling technologies for a top down strategy and simultaneously refined the costs of using a top down strategy	↑↑

Table 8 Changes made under governance

Change	Effect
Addition of LV generation other than PV at LV	—
Different DG/PV /PiV(low) dataset	↑
Explicit handling of Wind at HV/EHV	—
Different energy efficiency scenarios availible through drop down menu	—

Table 9 Changes made to resolve bug fixes

Change	Effect
Housing profiles now contain correct amount of electric heating	↑
Function to enter different DSR uptake scenarios to local Network Model added	—
Removed anomalous multiplier for transformer costs	↓
Energy efficiency applied to wet appliances	↓
Enablers now applied correctly in all instances	↓
Opex optimism bias no longer hard coded	—
Opex optimism bias no longer compounded with capex optimism bias for merit order purposes	—
Credit Purchase scenario adjusted such that it is now composed correctly of all low scenarios	↓↓↓
Automatic carry through of adjusted discount rate	—
Correction of GB model bug causing apparent changes in investment within same scenario	—

ANNEX 21: REINFORCEMENT MODELLING

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Contents

1. Executive Summary

Our network is designed to cope with the peak demand on it, such that it remains able to supply electricity even when demand is at its highest point. Demand fluctuates significantly through the day and the year such that there is often significant spare capacity not being used.

As demand for electricity grows in the future, we have to ensure that the network is adapted to cater for these additional demands. The forecast need to adapt the network is set against the regional economic forecast for our operating area and the wider context of the UK fourth Carbon Budget Plan that seeks to reduce CO_2 emissions by 35% (from 1990 levels) by 2023 and by 80% by 2050.

To deliver the fourth Carbon Budget, it is anticipated that demand for electricity will increase, with a doubling of demand by 2050 possible; however there is significant uncertainty as to when and where the increase in observed demand will materialise.

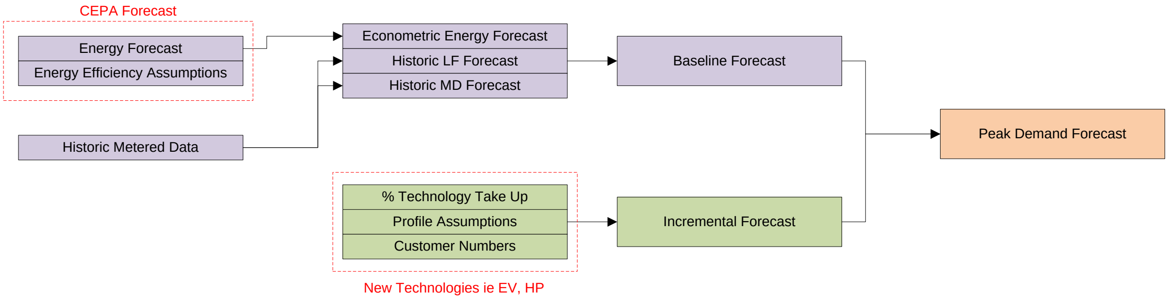
The Department of Energy and Climate Change (DECC) have prepared four potential scenarios for the impacts of de-carbonisation and forecast take-up rates for Low Carbon Technologies (LCTs) such as Electric Vehicles (EVs).

Within the RIIO-ED1 period, our stakeholder engagement and analysis shows that our region is likely to emerge more slowly than others from the economic recession and that its record of new technology adoption lags other areas. As a result, the forecast adoption rates will be relatively lower than other areas such as the south east. We therefore believe that the DECC Low scenario represents the most likely scenario for LCT adoption for our region.

2. Demand Forecasting

In order to identify those parts of our network that require future reinforcement, we need to develop an approach that forecasts future demand and can model the impact of any additional demand on the existing network.

Our demand forecasting methodology delivers a peak demand forecast that consists of a baseline forecast and an incremental forecast as shown in the figure below.



The baseline forecast predicts the annual peak demands that we would expect to see based on the typical types of demands connected today and as affected by forecast economic activity.

The incremental forecast predicts the impact of known large new connections, and perhaps more significantly, the impact of achieving the fourth Carbon Budget.

2.1 Baseline Forecast

We commissioned external experts CEPA to produce a background (or 'business-as-usual') energy forecast to 2023 from a base position at 2011. The forecast used several economic growth and electrical appliance efficiency saving assumptions to produce a load growth forecast.

The economic factors, and their source data, which have an impact on electricity demand in these scenarios are:

Factor	Source
Economic growth (GVA)	North West Economic Forecasting Panel
Household Income	equated to productivity figures
Housebuilding rates	Office of National Statistics
Price of Electricity	DECC central case for domestic/commercial prices

Non-economic factors which affect electricity demand are energy efficiencies brought about by policies on lighting, product efficiency and smart meters.

In overall terms, we anticipate that the UK economy will recover from the current recessionary state, however the North West region of England typically lags behind other areas of the UK in respect of economic performance. For the purpose of the RIIO-ED1 forecast, we have therefore adopted the CEPA central scenario as the appropriate balance between strong growth and a stalled economy.

Since our original submission we have revisited the assumptions underlying our forecast and are confident that they remain valid. We have also examined winter 2012 load data and whilst at the micro level some symmetrical changes are evident, the net effect within the overall uncertainty of the forecast is negligible.

The ratio of average load to maximum load gives the Load Factor (LF) on a piece of equipment. For a constant Load Factor (LF), the energy forecast is directly proportional to the power forecast. However, it has been observed that LFs have been reducing in recent years, ie the difference between average and maximum has been growing and the load is getting more 'peaky'. To convert the energy forecast into a power forecast, a forecast of LF is required for each Bulk Supply Point (BSP). The LF forecast is produced using regression analysis techniques operating on cleansed historical LF data.

A second power forecast is produced using regression analysis techniques operating on cleansed BSP historical annual peak demands.

The two power forecasts are combined into a single baseline forecast of power disaggregated by BSP.

2.2 Incremental Forecast

The incremental forecast addresses demand growth caused by known significant new connections (those not covered by the background factors considered by CEPA) and by the increasing connection of new low carbon technologies (often driven by external atypical factors such as government incentives), which cannot be predicted by a forecast based on historical data. In particular, during RIIO-ED1 we anticipate a potentially significant take up of EVs and HPs that will impact on peak demands, particularly beyond 2020.

The incremental forecast is added to the baseline forecast to produce the peak maximum demand (MD) forecast.

Having established a regional forecast, we then need to break this down further, as not all parts of our region will behave in the same way. To reflect more adequately the sub-regional adoptions of LCTs within our network; for example EV adoption rates in Manchester versus Ulverston, we have assumed EV and HP penetration levels consistent with DECC's Carbon Plan nationally but at levels appropriate to each Local Authority (LA) within our area.

The Tyndall Centre (part of the University of Manchester) has advised us on the take-up of these LCTs by Local Authority area based on known uptake and clustering observed with the take-up of PV cells. For EVs, we have based the sub regional forecast on the Transport Research Laboratory forecast for our region.

Our 'best view' reinforcement expenditure forecast assumes a peak demand forecast that is aligned to DECC scenario 4 (Purchase of international credits).

3. EHV and 132kV General Reinforcement

3.1 LI methodology

In order to measure performance in respect of efficient management of 132kV and EHV network capacity and delivery of reinforcement projects that provide increased capacity, we use a Load Index (LI) measure that ranks the ability of the parts of the network to supply maximum demand.

In order to establish the Load Index for all parts of the network, our network is sub-divided into groups. All groups which consist of a single substation are included in the analysis. Where the group is formed from a number of substations, only those that are considered material are identified.

To model the LI, the Firm Capacity (FC) of all the groups is calculated. This represents the maximum load that the site can provide. Where the group is a single substation this is a relatively easy task that relates to plant capacity and transfer capability, and is constant annually (for a fixed network configuration). Where the group is formed from a number of substations, the FC can only be calculated by network modelling techniques.

The 2023 forecast peak demands are applied to the groups and compared against the calculated FC to establish the groups' Load Index (LI).

The Load Index classification corresponds with that required by Ofgem and uses the following five point scale;

LI band	Descriptor	MD/FC	Time over 100%
1	Significant Spare Capacity	0-80%	n/a
2	Adequate Spare Capacity	80%-95%	n/a
3	Highly Utilised	95%-99%	n/a
4	Fully Utilised – Consider mitigation	>=100%	<9 hours
5	Fully Utilised – Mitigation required	>=100%	>9 hours

For all groups with a forecast 2023 peak demand greater than 100MW, an additional N-2[1] compliance assessment is also carried out and any non-compliance identified.

A desktop exercise develops high level reinforcement solutions for all identified network issues. These solutions take into account the overall system performance and the status of

[1] That is, the ability of the network to withstand two simultaneous incidents

neighbouring parts of the network to ensure efficient and economic development of the network.

Having identified the issues and preferred solutions, the resulting projects are costed using the assumed construction costs in the RIIO-ED1 period. This includes an assumption for ongoing efficiency reductions through the period.

In order to ensure that a single integrated programme is planned, the requirements of the reinforcement programme are matched against those from other drivers to ensure that any duplication is removed and that the proposed solution meets the needs of all relevant drivers on that site or portion of network.

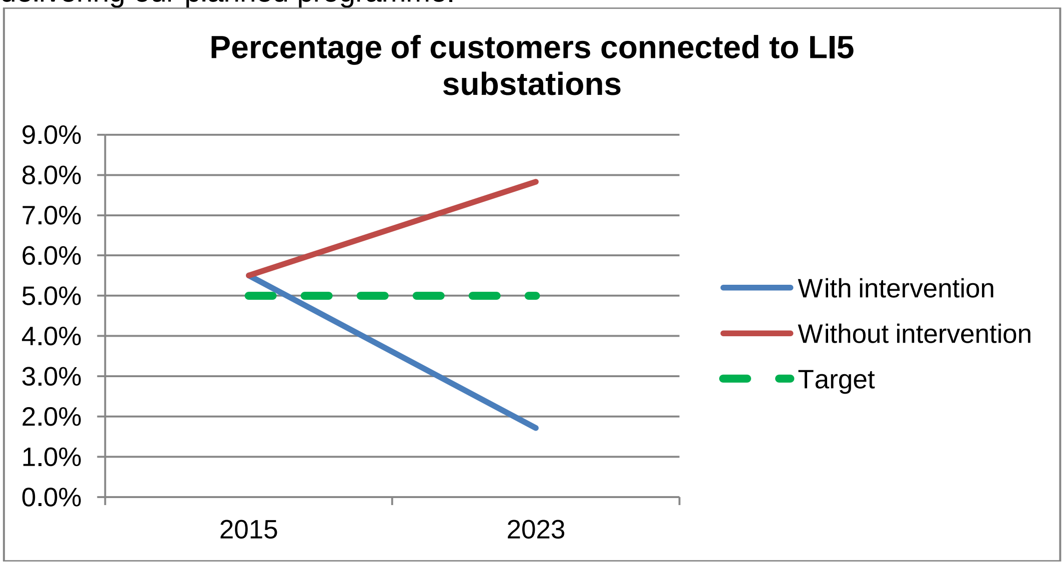
The profiling of expenditure takes into account the most heavily overloaded demand groups, demand groups with limited alternative feeds and deliverability constraints. Other considerations include avoiding simultaneous projects in the same area of the network to avoid operational difficulties obtaining the necessary outages and ensuring a smooth, efficiently deliverable programme.

The peak demand forecasting methodology intrinsically includes new demand brought about by new connections. Therefore, the identified reinforcement projects include reinforcements under the Low Volume High Cost (LVHC) Connections category. A reduction in general reinforcement expenditure is included to address this forecasting overlap. The size of this reduction is equal to the gross (of contributions) amount of connections related reinforcement specified in the connections submission.

3.2 LI strategy

Using a weighting of the LI grades (1-5) against each other and the customers supplied by each substation as an aggregating factor, we can total the overall 'loading risk' at a point in time and see how this changes in the future, both with and without the impact of proposed investment.

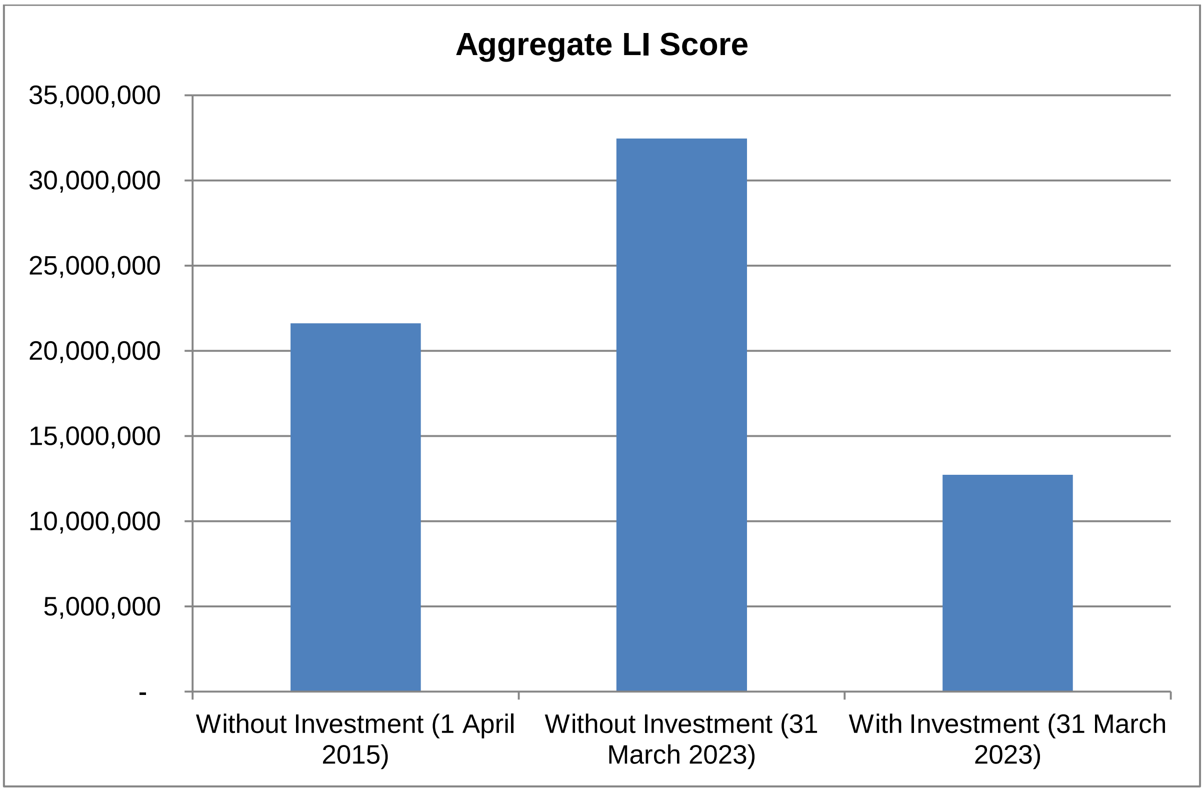
We can also articulate this in terms of the numbers of customers connected to overloaded substations. We forecast that this will be around 5.5% at the end of DPCR5. If we make no further investment, this will increase to 9% by 2023, however, we will reduce this to 1% by delivering our planned programme.



The actual needs and requirements of the network depend on future load growth, which is uncertain and difficult to predict. Therefore we do not propose to commit to specific LI targets for this programme as it could incentivise unnecessary investment. In RIIO-ED1, a re-opener mechanism will operate to share the financial risk if the pattern of demand growth and consequent investment requirements are substantially different from forecast.

We plan to reinforce 21 major sites and five groups during RIIO-ED1 at a cost of £39.3 million.

In overall terms, the weighted LI risk will halve from its projected 2015 level following the proposed investment rather than double as it is otherwise projected to do. This is due to the planned reinforcement of a small number of sites in the LI=5 category with large numbers of connected customers in the RIIO-ED1 period.



4. LV and HV General Reinforcement

We have developed a software model for the whole of the HV (feeders from the primary substations) and LV network that allows network overloads at these voltages to be identified. This model is termed the Future Capacity Headroom (FCH) model.

Inputs to this model are plant ratings and existing loading levels derived from corporate data, and the peak demand forecast. The same baseline forecast is used for loading on a particular asset as that calculated for its supplying BSP and the same incremental forecast is also used; however additional assumptions are made about the distribution/clustering of the incremental forecast, ie the distribution/ clustering of the penetration of the LCT take-up.

Outputs from the model are counts of assets that are loaded beyond their thermal rating. The uncertainty in exact location of LCT penetration means that the results for future overloads are only valid as counts in aggregate and cannot be asset specific.

The FCH model also counts assets where the installed thermal capacity of LCT (including PV) exceeds an indicative threshold of thermal rating indicating when voltage/harmonic issues are likely to occur at the LV network level.

Modular solutions and associated costs have been developed to address the following issues on the HV and LV networks:

- Thermal overloads – HV feeders
- Thermal overloads – LV feeders
- Thermal overloads – distribution (HV/LV) transformers
- Over-voltages – LV feeders
- Harmonic issues – LV feeders/Distribution substations

Some older properties, typically terraces and townhouses, are supplied by a looped service cable where a single cable is taken from the low voltage main cable and is 'looped' from one property to the next to provide the electricity connection. This means that the electrical demand of a number of properties is supplied from service rather than mains cable.

Historically this has been acceptable because of limited demand and diversity across demand. However in the future, LCT devices such as electric vehicle chargers will require large amounts of electricity and there will be a high probability that they will be simultaneously used in a number of properties. If these properties are fed from a looped service cable, that cable will quickly overload and fail. We are therefore proposing to address this issue by removing looped services and providing discrete services to each property.

The profiling of this expenditure over the RIIO-ED1 period reflects the expected uptake of LCTs over the period.

For completion of our secondary network LCT driven reinforcement submission, we have used the Transform model developed by EATL for all the GB DNOs to assess the impact of Low Carbon Technologies on GB electricity distribution networks (See Annex 20) with appropriate regional settings as detailed in our submission tables. The FCH model has been used to both verify the outputs of the Transform model against 'traditional' solutions and to derive the forecast for elements such as harmonics not covered by Transform.

5. Smart Grid and Smart Meter benefits

We have carried out considerable work on smart grid (see Annex 29) and smart meter (see Annex 28) based solutions as an alternative to traditional network reinforcement techniques for both demand and generation customers. This work has been led by ourselves in areas such as DSR, active voltage management and meshed network techniques but also done by or in collaboration with other DNOs through various industry working groups and other DNO projects. Whilst it is not possible to define the exact smart grid / meter solution that will be applied to every intervention required in RIIO-ED1 we have ensured the forecast benefits of this work are appropriately included within our forecasts and hence accrue to our customers.

For secondary network expenditure we have based the majority of our forecast on the Transform model. Certain investment drivers such as service un-looping and power quality are not covered within the Transform model and for these we have modelled the required volume using our Future Capacity Headroom model and priced using modelled unit costs. Transform contains details of all known smart solutions and incorporates all solutions contained within our smart grid strategy. In particular, we would expect to deploy network meshing, voltage management and DSR on secondary networks and have included this smart grid discount within our forecasts.

For the 132kV and EHV system we have calculated our base reinforcement requirement on traditional solutions priced using efficient unit costs and then discounted the price by 20% to reflect the value we expect to deliver from deployment of smart solutions such as C_2C DSR developed by ourselves and techniques such as active network management pioneered by SSEN.

In addressing our forecast reinforcement programme we have also closely examined the likely challenges presented by Distributed Generation customers. We have included a modest forecast for DG-driven reinforcement as we intend to utilise C_2C managed connection contracts at EHV and HV and connect and manage techniques at LV. These approaches we believe will enable significant amounts of DG to be connected at lower costs on already congested networks. In specific areas we envisage deploying site- based Active Network Management solutions; however our overall strategy for DG is to develop and deploy centralised active network optimisation. We have included costs for this as part of our NMS replacement project (see Annex 18).

Smart metering will bring further benefits to customers and assist in reducing network load-related expenditure. In particular we expect to see the information from smart metering advising loading levels on existing assets and hence allowing us to run assets closer to their operational limits. Again such techniques and benefits are included within the portfolio of smart solution sets within Transform and hence are already included within our forecast. We would envisage smart meter benefits to become much more significant during the RIIO-ED2 period and have outlined these out of period savings in Annex 28 – Smart Meter Benefits.

6. Demand Side Response (DSR)

We have been looking at the role that DSR contracts can play in mitigating reinforcement investment requirements in DPCR5 and have instigated a number of contracts with industrial customers in the period. DSR contracts are a possible option where there is some doubt over the sustainability of load growth and hence a risk of under-utilised investment if additional capacity is installed, or where the load characteristics driving the loading issue are related to a single customer. They are also useful mechanisms to buy some time where proposed network solutions that may solve multiple loading issues are in development. As such, we see them as a useful intervention strategy.

The actual number and value of contracts signed will depend on the economic case in each instance, and the willingness of customers to sign up to such an agreement.

Our CBA analysis of techniques such as C_2C shows a strong benefit of such DSR approaches – for further details please see Annex 3. For secondary network investment, DSR is one of the smart solution sets within Transform and hence is included appropriately in our submission. As noted, we have discounted our plan for Grid and Primary reinforcement by 20% to reflect the anticipated DSR benefits of solutions such as C_2C, CLASS and other learned approaches from smart trials.

7. Fault Level Reinforcement

The equipment that forms the electricity distribution network has to be able to cope with the large amounts of electrical energy that flow when faults occur. The amount of energy that would flow in a particular part of the network under worst case conditions is known as the fault level.

Some areas of our network have older items of equipment connected which have a limited ability to cope with high levels of fault energy (a lower fault level rating). We have designed our network to limit the fault energy to be as low as possible at this equipment in order to maintain safety, but this does constrain our ability to connect new sources of electrical energy like distributed generation, as well as the widespread adoption of LCTs, in a particular area.

In RIIO-ED1 we are proposing to remove equipment that we have identified as not having a fault level rating consistent with modern standards and that is potentially constraining new LCT connections and the way we operate the network. Replacement of this equipment typically has long lead times of up to two years and hence to facilitate the prompt connection of LCTs by customers it is proposed to remove this sub standard switchgear from the network over two price control periods.

7.1 Modelling

Calculation of 132kV, 33kV and HV (at primary substation busbars) fault levels is undertaken through network modelling. We use the IPSA+ network analysis tool and maintain an IPSA Network Model (INM) of the 132kV, 33kV and HV network. The model also incorporates a reduced representation of the transmission network, which is set up for maximum fault level operating condition.

The INM has been updated with the 2023 peak demand forecast and the corresponding G74 motor in-feed contributions. The transmission system is assumed to remain constant. Fault 'make and break' calculations are undertaken for three-phase and single-phase short circuit faults. Switchgear calculated to have a fault level in excess of its fault rating has then been identified for replacement or reinforcement.

A desktop exercise developed high level reinforcement solutions for all identified fault level issues. These solutions take into account the overall system performance and the status of neighbouring parts of the network to ensure efficient and economic development of the network.

Costs were developed for the preferred solutions based on our projected view of unit costs and consistent with future efficiency assumptions. As was the case with the reinforcement programme, any overlap with the asset replacement programme was reviewed and duplicated units removed from the fault level forecast.

7.2 Options

Fault level management is a critical network safety factor and at this time we do not consider that alternate technology solutions such as fault current limiters will be economically viable at EHV in the RIIO-ED1 period. All solutions selected are therefore based on proven techniques and we have identified the construction delivery risks (equipment outage risk, consents acquisition risk etc) and designed what is believed to be a deliverable solution within the RIIO-ED1 period.

Our CBA analysis indicates that use of alternate solutions such as fault current limiters is currently uneconomic for several reasons:

- The capital cost of such solutions is comparable with traditional solutions however such devices have a relatively high operating cost;
- The plant concerned is generally towards the end of its operating life and will require replacement on HI grounds before the end of RIIO-ED2; and
- The technology risk arising from the present embryonic manufacturing base for these devices precludes a rapid and reliable deployment programme.

We will monitor ongoing smart technology developments and where possible incorporate these into our actual delivery plan. This is an area of active research in our innovation plans and we have included two new potential techniques within our innovation strategy to manage future fault level issues on EHV networks (see Annex 23). These techniques are revolutionary in nature and consequently at a low technology readiness level hence we have not factored them into our forecast.

7.3 HV and LV Fault Level Reinforcement

The conurbations within our operating area have HV networks operating predominantly at the 6.6kV level. A proportion of the switchgear in these areas is fault rated below the present UK design standard of 21.9kA. This equipment often represents a significant barrier to the connection of LCTs such as heat pump motor load and DG. Replacement of this equipment typically has long leads times of up to two years and hence to facilitate the prompt connection of LCTs by customers it is proposed to remove this sub standard switchgear from the network over two price control periods.

The criteria used to identify and prioritise 6.6kV secondary network switchgear for replacement are:

- Fault level rating of switchgear is less than 20kA
- Current feeding primary substation HV fault level greater than 13.1kA
- Current feeding primary switchgear greater rated greater than or equal to 20kA.

The above criteria identify all 6.6kV switchgear rated less than 20kA where there is a likelihood of the fault level rating exceeding equipment rating and allows for the grouping of switchgear changes by primary substation. This strategy allows us to certify that a particular primary is unlikely to have fault level issues for connection of LCTs and hence release the maximum amount of capacity in the shortest time.

We have examined all present innovation work in the area of HV fault level management. Our analysis shows that for the particular issues we face; namely HV Ring Main Unit ratings remote from primary substation sites, then the optimal intervention given the asset age and condition is to replace with modern equipment.

Costs for replacing the 6.6kV switchgear are based on a like-for-like replacement using standard unit costs and any overlap with the non-load programme has been removed as stated above.

ANNEX 22: LONG TERM STRATEGY

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Contents

1. Background

In forming our plans for RIIO-ED1, we have been careful to take account of the longer term context in which those plans will be delivered.

To help us do this, we have explored the potential longer term impact of moves to a low carbon economy with our stakeholders and also considered the requirements of the existing network over the next few decades. For the last three years, we have published annual Strategic Direction Statements which outline our current thinking in these areas and the future impacts we expect.

The overall backdrop is provided by government-instigated moves towards de-carbonisation of the energy sector as part of the plan to achieve legally-binding national reductions to overall carbon emissions by 2050. This is likely to result in a significant increase (potentially 60%) in electricity demand due to the decarbonisation of the transport and heat sectors. In addition to this, we will have to take account of the needs of an extensive and ageing existing asset base and ensure that we continue to comply with all our current obligations.

Long-term forecasting is always fraught with uncertainty, particularly where the future may hold a very different pattern of energy usage from that of today. However we have constructed a range of plausible forecasts rooted in currently available information and analysis of our current network.

We have broken down our longer-term forecasts into four key areas;

- Asset Renewal;
- Other Non Load investment;
- Low Carbon Reinforcement; and
- General reinforcement.

In addition, we have included consideration of a particular issue in terms of the proposed construction of a new nuclear power station at Moorside on the west coast of Cumbria in the period to 2023.

2. Approach

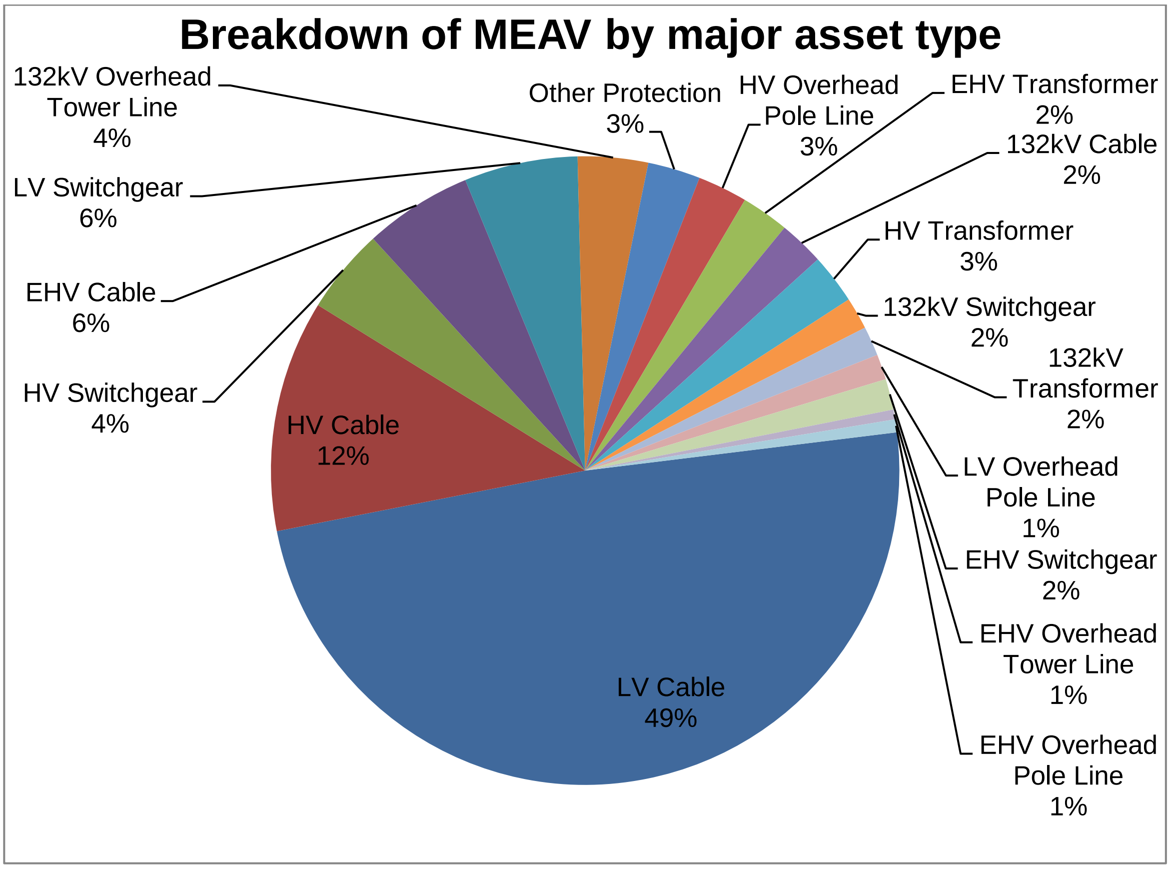
Detailed forecasting models become increasingly unreliable as their time horizon is extended so for longer-term planning we have used a more strategic approach for each area as set out below. In each case, the results are presented in terms of the total forecast for a RIIO price control period (eight years). These costs relate to the forecast direct construction costs of the work. We have not included ongoing maintenance costs or the indirect costs of running our business over the forecast period in these projections.

3. Asset Renewal

Historically, the major component of our network investment programme has been the replacement and refurbishment of our existing electrical and civil assets as they reach the end of their useful life. Much of the asset base was installed in the 1950s and 1960s and hence renewal rates have been relatively low over recent decades as the overwhelming majority of the assets have been within their design lives. However, we have already seen the start of an increase in renewal requirements in DPCR5 as a large number of assets start to approach the end of their useful lives.

Modern asset management and condition monitoring techniques assist in effectively prioritising replacement requirements and identifying where additional asset life can be achieved. This can help constrain investment from the levels that would otherwise be required; however the background pattern of investment in this area is that of an inexorable rise over the next few decades.

We do not believe that the future increase in investment will replicate the originally-installed profile, but will be much more incremental over time. The pattern will also differ significantly by major asset type. The chart below shows the composition of the current network Modern Equivalent Asset Value (MEAV), ie the current cost of replacing the whole network;



The valuation is dominated by the LV and HV underground cable networks (including services). These assets have been extremely reliable historically and there are no current indications that overall performance levels are worsening. These assets are however very difficult to inspect and condition assess hence it is difficult to build predictive models. Assumptions on the future replacement rates of these cable networks are the biggest variable in long-term renewal projections.

For the other asset types, it is possible to undertake condition assessments which can be used to inform future replacement requirements. We utilise a suite of Condition-Based Risk Management (CBRM) models to enable us to identify these requirements. Annex 2 gives further details on the development of this approach and details the results for the RIIO-ED1 period.

For the longer-term projections, we have reviewed the overall replacement percentages in RIIO-ED1 and used these as a baseline for assessing future periods, taking into account the deterioration trends suggested by the CBRM models.

The results by major asset type are set out below with further details in Appendix 1;

		RIIO-ED1		**RIIO-ED2**	**RIIO-ED3**	**RIIO-ED4**	**RIIO-ED5**	**Total by 2055**
	Total Number	Volumes	% replaced					
Transformers	34,475	1,784	5%	12%	10%	10%	10%	**47%**
Switchgear	85,729	11,076	13%	11%	10%	10%	9%	**53%**
Overhead Lines	12,923	620	5%	10%	11%	11%	11%	**48%**
Underground Cables	44,193	542	1%	2%	3%	4%	4%	**15%**

This shows that, even with planned increases over future periods, around half of the current switchgear, transformer and overhead line assets will still be in service in 40 years' time. In terms of the cable network, it is likely that around 85% of the current inventory will still be in use. Increased use of refurbishment and life extension techniques, together with the replacement of assets due to other investment drivers will contribute to these being credible projections; however they are likely to be towards the bottom of the potential range of future renewal investment.

One key conclusion from this is that much of the additional functionality required of the network in a 'smart' world will have to be enabled by retrofitting technology to pre-existing assets.

4. Other Non-load Investment

In addition to asset replacement, there are a range of additional drivers which result in the replacement of existing assets, whether due to legislative drivers or responding to demands for increased resilience of and performance from the network.

Predicting future requirements in this area is difficult as such changes are often made in reaction to unforeseen or extreme events. The table below sets out our forecast spend in these areas, together with the outline assumption for each. In general terms, we have not included speculative provision for currently unknown requirements and hence the forecast shows a decrease over future periods as areas of current concern are addressed.

2012-13 prices	2016-2023	2024-2031	2032-2039	2040-2047	2048-2055	Assumptions
	RIIO-ED1	RIIO-ED2	RIIO-ED3	RIIO-ED4	RIIO-ED5	
Diversions	27.2	30.0	30.0	30.0	30.0	No new requirements
Legal & Safety	43.0	25.0	20.0	20.0	20.0	Current security & safe climbing programmes complete. Continuation of mitigation measures only thereafter
Resilience	20.7	15.0	25.0	15.0	25.0	No material new requirements following CNI & Black Start implementation in ED1. 10 year battery replacement cycle
Rising & Lateral Mains	14.5	30.0	20.0	5.0	5.0	Resolution phased over ED1, 2 & 3. Provision thereafter
Losses & Environmental	16.2	20.0	5.0	5.0	5.0	Implementation of new transformer spec over ED1 & 2. Residual provision thereafter
Other Non-Load	**121.6**	**120.0**	**100.0**	**75.0**	**85.0**	

5. Low Carbon Reinforcement

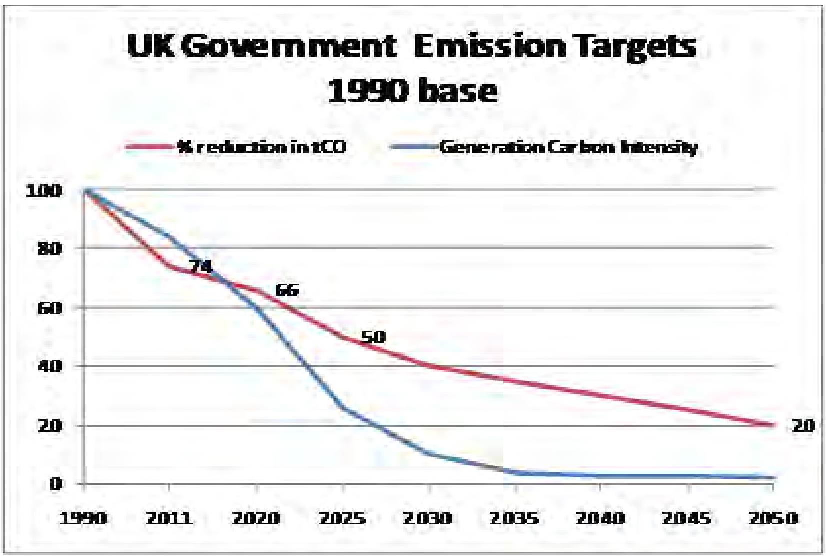
One of the most uncertain future factors to consider in long-term planning is the future network implications of the wide scale adoption of Low Carbon Technologies (LCT) such as Electric Vehicles, Heat Pumps and domestic PV generation.

These are particularly important as their demand patterns are completely different in scale and character to existing domestic level loads and this has the potential to render much of the current lower voltage network unable to connect such devices.

In order to make a meaningful forecast, we have to a) consider the likely network impact of varying scales of LCT penetration and b) consider the likely timeframe for the roll out of these devices.

In terms of assessing the network impact, we have used the Transform model developed collectively with the industry and third party experts. This looks at the ability of different types of network to accommodate LCTs and selects from a range of potential solutions when it considers the network's ability to have been exceeded. Using this approach means we can model the potential implications in a consistent way across the industry.

In terms of the likely roll-out timeframe for LCTs, our forecasts for RIIO-ED1 have been based on one of four scenarios articulated by DECC. Our 'Best View' aligns with the 'Low' scenario. We have continued this projection over future periods and calibrated it by RIIO period using the target rate of CO_2 reduction (see chart below).

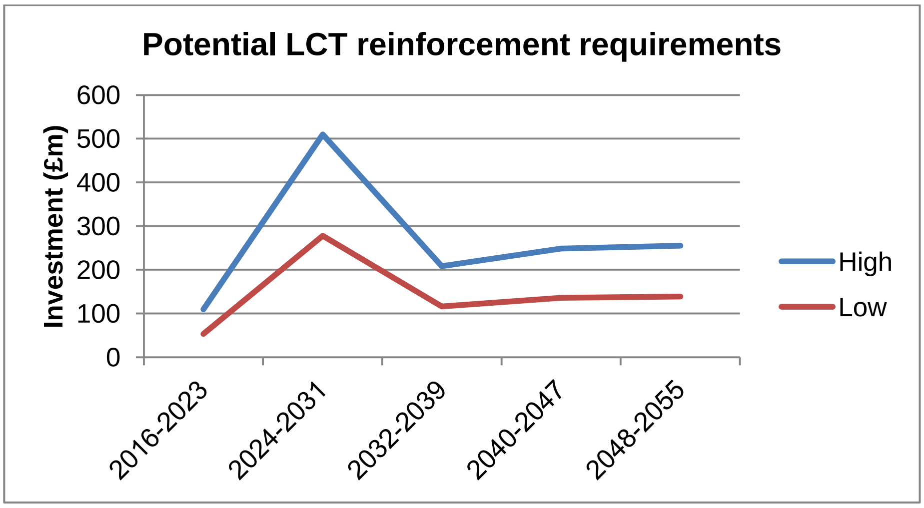


This results in a significant increase in the RIIO-ED2 period as that is when the rate of decarbonisation will be at its most rapid.

We have taken two further factors into account in constructing the forecast. Firstly, we consider that the current research effort and technology trials will reveal new and cheaper solutions to the emergent demand issues. We do not currently know what these will be, but we have discounted our projections by 25% in each period on the assumption that new technologies make these reductions possible.

Secondly, as the scale of investment grows, so does the potential overlap with other programmes of work, particularly the asset renewal programme. We will not know the specific locations where this overlap occurs (and hence where multiple needs can be solved by a single project) until the detailed planning phase of the programmes but we have assumed a further 20% discount on the costs of responding to decarbonisation due to the likely overlap with other work.

For comparison, we have also looked at the potential impact of LCT technology take-up if the future resembled the 'High' DECC scenario for our region. We believe that this is less likely, but it gives an illustration as to the range of investment that might be required in this area.



6. General Reinforcement

Every year, we undertake reinforcement of the existing network to accommodate increases in demand. This may require the upsizing of assets that were otherwise still serviceable, or the re-configuration of part of the network (eg through installing new cables interconnecting circuits) to enable us to manage load more flexibly.

Patterns of demand growth are not consistent through time and across our region. They do however generally follow economic activity and it is possible to make near-term projections of the impact of this at quite a detailed level. As such, our RIIO-ED1 forecast is comprised of projects at specific sites for the higher voltage networks, together with overall forecasts at the lower voltages based on trend analysis.

The recent economic recession has resulted in a drop in overall demand, however in our region, we experience localised load growth ranging from 4%-5% per annum in central Manchester through to sustained decline in a number of former mill towns. Even if overall demand is falling, we will still need to respond to these localised needs.

Our long-term forecast is that economic growth will slowly return to pre-recession levels resulting in an enduring demand growth of 1%-2% per annum (similar to the last 20 years). Continuation at this rate will result in a doubling of demand by 2050. As a result, our forecasts for general reinforcement show an incremental period-on-period rise out to RIIO-ED5.

7. Cumbria Nuclear

NuGen has applied to National Grid Electricity Transmission for the connection of a 3.6GW nuclear power station, at Moorside near Sellafield. To enable this connection National Grid will need to provide 4 x 400kV transmission circuits. At present, no firm commitments on the timing of the connection works or the route for the transmission circuits have been made.

National Grid has considered six options for this connection. One of these has a significant impact on our 132kV distribution network, whereby National Grid's proposals would mean displacing our existing lines to establish a 400kV overhead line double circuit around the west coast of Cumbria.

We have included a total estimate for this work within the RIIO-ED1 period. We do not expect our customers to meet any part of National Grid's costs or the consequential costs of accommodating their chosen route. It is likely though, that we will have to upgrade or replace some of our assets as a result. Our current estimate is that around 45% of the £207m estimated cost will be funded by our customers, with the remainder being recharged to National Grid.

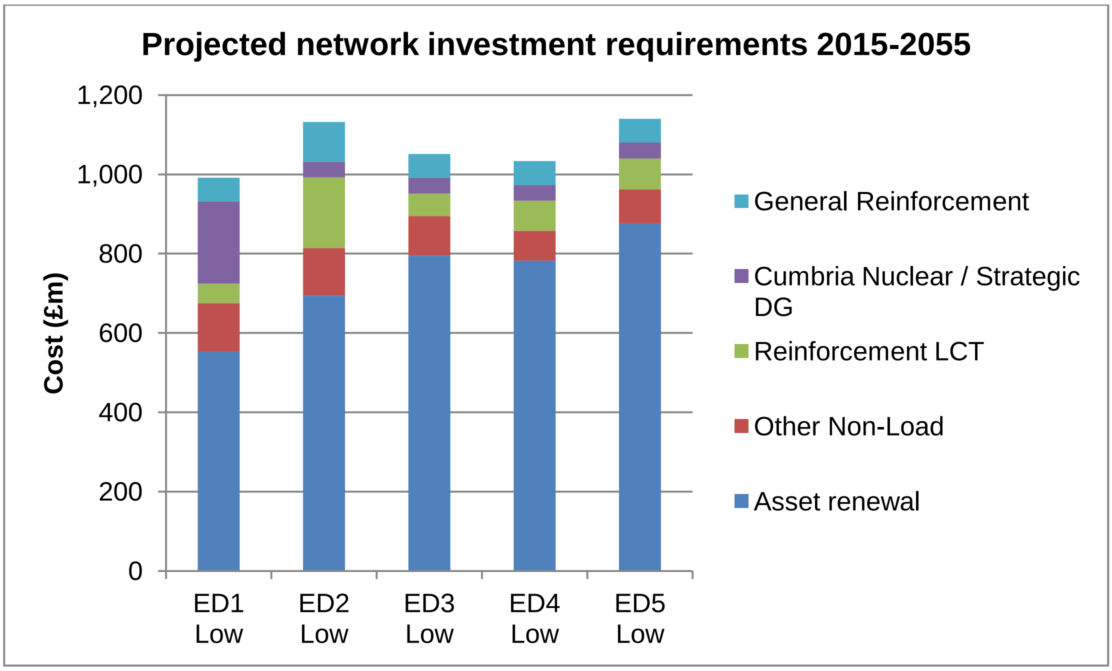
8. Strategic Reinforcement

As the pattern of future demand requirements becomes clear, it is likely that it will be economically advantageous to undertake a small number of strategic network reinforcement projects where this is more efficient that responding to issues on a piecemeal basis. At the moment, it is impossible to identify where these may be required but our previous experience of areas such as South Manchester is that it can be possible to solve multiple emerging issues with a single wider-scale reinforcement project.

As such, we have included an assumption for future such works in our forecast.

9. Overall Summary

The total forecast network investment requirements over the next forty years as a result of the drivers noted above is as follows;



10. Implications

This analysis has a number of important implications for our RIIO-ED1 plan. These fall broadly into three separate categories, namely:

- The level of reinforcement investment that can be brought forward into RIIO-ED1
- The resource capability development that can commence in RIIO-ED1
- Ensuring the appropriate contracting strategy

11. Level of reinforcement investment that can be brought forward into RIIO-ED1

Our stakeholders place a higher priority on ensuring affordability of customers' bills than they do on facilitating the move to a low carbon future. We have been very conscious of this in developing our plan. The scale of the potential increase in reinforcement expenditure that we forecast for RIIO-ED2 and RIIO-ED3 is such that we have considered very carefully whether we should bring forward some of this work into RIIO-ED1. If it were possible to do so we could mitigate the cost pressures that outage congestion and competition for contractor resources will inevitably bring. These benefits would potentially have a positive impact on customer prices over the long-term; however we need to remain mindful of the risk of building assets that are not utilised in the near term.

The need for the reinforcement levels we have predicted will only arise if there is a significant change in the current package of Government stimulus to the heat pump and electric vehicle markets. Beyond the implementation of the revised Renewable Heat Incentive, at the current time we are not aware of any evidence that Government are contemplating further revisions to their stimulus package within the RIIO-ED1 period. Our stakeholders also tell us that they do not expect changes in this period.

In five years' time we may have much more information and the picture may be much clearer. If this is the case, we anticipate that the Government will enact the necessary legislative changes to introduce new stimulus packages or we will be asked to provide additional, specific Outputs to support the move to a low carbon future. These occurrences may trigger the need for a mid-point review of the remainder of RIIO-ED1.

We are very conscious that to ensure maximum efficiency we must avoid the risk of unnecessary investment wherever possible. Our key dilemma in assessing reinforcement expenditure targeted at supporting the growth in Low Carbon Technologies (LCTs) is determining the precise location for this reinforcement. Given this we have included a relatively modest plan in addressing low carbon-driven reinforcement during RIIO-ED1, but one that can ramp-up quickly when required in RIIO-ED2.

11.1 EHV and 132kV networks

On our EHV and 132kV networks, we see a continually shifting pattern of peak demands. Overall demand has been falling, but at localised hot spots we have significant reinforcement requirements. The overall impact of LCTs on this network is hard to predict without good data on the likely clustering of their adopters and an accurate forecast of when the technologies will be adopted in significant numbers.

We do not believe that the increase in reinforcement needs we have forecast for the RIIO-ED2 period will occur at the end of RIIO-ED1 and is more likely to be needed from the middle of the period onwards. Therefore, during RIIO-ED1 we have focussed on addressing the most heavily overloaded demand groups and separately those demand groups with limited alternative feeds.

11.2 HV and LV networks

The urban conurbations within our operating area have HV networks operating predominately at 6.6kV. A proportion of the switchgear in these areas is fault rated below our design standard of 21.9kA. Although the standing fault level may not exceed this rating, it often represents a significant barrier for significant load or generation increases, such as LCTs or urban DG. It is proposed to remove this sub standard switchgear from the network over two price control periods to coincide with increased penetration of LCT which may otherwise be constrained or unacceptably delayed. The volumes for intervention in RIIO-ED1 are forecast to cost some £14m with the remainder of the switchgear to be changed in RIIO-ED2. The fault level on the primary HV busbar coupled with the rating of the primary HV switchgear is used to prioritise intervention. This strategy allows us to certify that the whole network emanating from a particular primary substation will not have fault level issues that would impede the connection of LCTs.

The electrical nature of LCT connections will increase harmonic levels on the distribution system. This is of particular concern to the LV network as the penetration of photovoltaic generation, heat pumps and electric vehicle chargers increases. Using analysis we commissioned from Parsons Brinckerhoff, we will commence a programme of fitting LV harmonic filters to substations identified as having harmonic issues during RIIO-ED1, ramping up into RIIO-ED2.

Our work on looped services shows that these are not compatible with persistent LCT loads such as heat pumps due to thermal heating effects and voltage drop. We therefore propose to address looped services that constrain the connection of LCT to the network. In RIIO-ED1 we will also remove all looped services where we have another driver to work on these assets.

12. Resource capability development that can commence in RIIO-ED1

Our delivery strategy is to use a blend of direct labour and contractor resources. We are developing the future capability and capacity of both of these resource pools in anticipation of the growing investment programme our long-term strategy sets out.

In designing our delivery model for our business plan we have been mindful of the need to be able to flex resources in the event that LCT adoption rates are higher than anticipated. Our delivery plan shows how we will be able to increase our contract resources and flex our less time-critical investments to accommodate any reasonably foreseeable level of LCT adoption up to and including the highest of the DECC scenarios.

We also note that much of the RIIO-ED2 and RIIO-ED3 reinforcement will require considerable cable-laying activity which presents fewer delivery challenges in terms of available market capacity than, for example, overhead lines work.

12.1 Work Force Renewal

Our Work Force Renewal (WFR) recruitment and training strategy is a key element of our resource capability and is based on a strategic view of the workforce requirements we will have over the next 15 years. During this period, the demographic profile of our workforce will change dramatically, presenting challenges in terms of replacing an aging workforce, developing our delivery capacity and developing a new range of skills.

We are meeting the challenges by recruiting apprentices, A level, HNC and graduate trainees; this will be further supplemented by an upskilling/re-skilling programme for existing employees.

As a result of our long-term network planning, we have used our strategic resource model during DPCR5 to determine our requirements for RIIO-ED1 and beyond. Our strategy is aligned to, and we are working very closely with National Skills Academy for Power (NSAP) and the other DNOs on utilising a WFR Planning Model.

Our new training academy was opened during 2013 and provides the infrastructure necessary to cater for the increase in recruitment and training. Our A level, HNC and graduate programmes have recently received IET accreditation and improvements to our craft apprentice programme were introduced in September 2012.

12.2 Contracting Strategy

Our delivery model is based on retaining a core of direct labour for reactive customer work and tree cutting with flexibility provided by contractors for other investment areas. This ensures security of fault response, retains key skills within our business and provides efficient cost delivery whilst maintaining flexibility for the business.

The balance of work will be completed by external contractors, procured through either framework arrangements or, for larger projects, via a formalised tender process. The approach of undertaking the additional volume by utilising external contractors is appropriate as we anticipate there will be sufficient flexibility in the market to accommodate the increasing work programme at an efficient cost and without the risk of building a stranded workforce.

We have assessed the potential increase in activities and volumes required when moving from a ‘Low’ to a ’Medium’, or even to a ‘High’ carbon reduction scenario. The difference in scenario outputs has been assessed using our resource analysis tool and the inbuilt flexibility within the delivery strategy can cope with these additional demands and changes should they be encountered during the course of RIIO-ED1.

Our only area of concern is that some specialist resources become limited in a stretched market and as a consequence command a premium price. It is therefore essential that early indicators are monitored regularly to determine the scenario developing.

We are already building closer links and exploring partnering arrangements with some of our contractors and supply chain to secure the future resources needed.

		Total Asset Length	RIIO-ED1 Volumes	%age replaced - RIIO-ED1	RIIO-ED2	RIIO-ED3	RIIO-ED4	RIIO-ED5	By 2056	Assumptions
LV	Overhead Pole Line	2,224	188	8.5%	15.0%	15.0%	15.0%	15.0%	68%	ED1 reduction due to ESQCR programme in DPCR5. Flat thereafter
LV	Cable	28,529	201	0.7%	1.5%	2.0%	3.0%	4.0%	11%	Gradually increasing to reflect age of asset base
LV	Services (OH, UG, RLM)	1,965,377	24,910	1.3%	11.0%	12.0%	13.0%	14.0%	51%	Replacements driven by a mix of condition and increased loading due to LCT take up for heat pumps, EVs etc.
HV	Overhead Pole Line	7,746	238	3.1%	10.0%	12.0%	12.0%	12.0%	49%	ED1 reduction due to ESQCR programme in DPCR5. Pick up thereafter
HV	Cable	13,105	249	1.9%	3.0%	4.0%	4.0%	5.0%	18%	Gradually increasing to reflect age of asset base
EHV	Overhead Pole Line	1,015	101	9.9%	8.0%	8.0%	8.0%	8.0%	42%	Reduction from ED1 programme
EHV	Overhead Tower Line	338	3	0.9%	2.0%	3.0%	9.0%	12.0%	27%	Very low volumes of activity in RIIO 1 - 3 will result in a large number of lines being very dilapidated toward the middle of the century, hence requiring increase in investment as lines will require total replacement.
EHV	Cable	2,207	108	4.9%	10.0%	15.0%	8.0%	8.0%	46%	Reflects planned phase out of assisted cable over medium term
132kV	Overhead Pole Line	4	-	0.0%	0.0%	0.0%	100.0%	0.0%	100%	This equates to approximately 40 structures which for the sake of completeness should be considered for replacement/refurbishment within the next 20 - 25 years.

132kV	Overhead Tower Line	1,595	90	5.6%	5.0%	5.0%	5.0%	5.0%	26%	Likely to be fundamentally based on ongoing refurb rather than replace
132kV	Cable	352	12	3.3%	10.0%	25.0%	1.0%	1.0%	40%	Reflects planned phase out of assisted cable over medium term
Total		**2,022,493**	**26,099**	**1.3%**						
HV	Transformers	33,602	1,680	5.0%	12.0%	10.0%	10.0%	10.0%	47%	Age profile suggests near term increase in replacement
EHV	Transformers	715	87	12.2%	10.0%	10.0%	11.0%	11.0%	54%	Reports show that newer transformers will fail more rapidly than older units hence need to continue with high levels of asset intervention, also LCN will result in increased loadings hence reducing life expectancy of existing fleet.
132kV	Transformers	158	17	10.8%	8.0%	8.0%	10.0%	10.0%	47%	Reports show that newer transformers will fail more rapidly than older units hence need to continue with high levels of asset intervention, also LCTs will result in increased loadings hence reducing life expectancy of existing fleet.
Total		**34,475**	**1,784**	**5.2%**						
LV	Switchgear - Cut Outs	1,965,377	40,497	2.1%	5.0%	5.0%	5.0%	5.0%	22%	Estimated run rate post Smart Meter roll-out
LV	Switchgear - ex. Cut Outs	37,049	3,624	9.8%	10.0%	10.0%	10.0%	10.0%	50%	Carry on at existing levels
HV	Switchgear	45,644	7,338	16.1%	12.0%	10.0%	10.0%	8.0%	56%	Reduction from planned ED1 peak in activity
EHV	Switchgear	1,917	69	3.6%	5.0%	9.0%	10.0%	8.0%	35%	Rise anticipated in ED3 due to longevity of current plant mix as many units will be approaching 100 years old.

132kV	Switchgear	1,119	45	4.0%	3.0%	5.0%	8.0%	10.0%	29%	Significant ramp up to reflect age profile and current low level of activity
Total		**2,051,106**	**51,573**	**2.5%**						
HV	Protection	3,176	1,776	55.9%	25.0%	20.0%	20.0%	20.0%	122%	Assumed near term major replacement programme then lower levels
EHV	Protection	816	648	79.4%	25.0%	20.0%	25.0%	30.0%	100%	The general assumption is that electro- mechanical relays will need replacement because their bearings will be too old to operate correctly, and then the replacement micro processor relays will only last between 20 and 25 years so population replacement rates will rise markedly over the period.
132kV	Protection	192	177	92.2%	25.0%	20.0%	25.0%	30.0%	100%	The general assumption is that electro- mechanical relays will need replacement because their bearings will be too old to operate correctly, and then the replacement micro processor relays will only last between 20 and 25 years so population replacement rates will rise markedly over the period.
Other	Protection	5,589	113	2.0%	5.0%	5.0%	5.0%	5.0%	22%	Provision for replacement of pilots etc.
Total		**9,773**	**2,714**	**27.8%**						

ANNEX 23: INNOVATION STRATEGY

Electricity North West Limited
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Registered no: 2366949 (England)

electricity north west

Bringing energy to your door

Our Innovation Strategy

March 2014

Our innovation strategy

Welcome to Electricity North West's innovation strategy document. This document describes how innovation plays a key role in helping Electricity North West deliver a responsive and sustainable business for our customers, stakeholders, and the millions of people who depend on us every day.

Innovation is one of our core values and we are leading the industry in developing innovative solutions that challenge and improve the way we do things for our customers and stakeholders. Our innovation strategy sets out why we innovate, in what areas our efforts are focused and most importantly the benefits to customers from our past and future innovation plans. Our track record in developing industry leading technologies and techniques within DPCR5 continuing into RIIO-ED1 has enabled us to commit to £131 million customer savings in our RIIO-ED1 business plan through cost avoidance and efficiency improvements.

Our innovation work spans the entire range of our activities; our work on condition based asset management techniques has fundamentally changed the way network assets are managed delivering tens of millions of £s of savings for customers; our smart grid work has pioneered new commercial and technical approaches that will deliver the transition to a low carbon economy at an affordable cost to customers. Our future innovation programme builds on this, encompassing both smart grid and smart metering to deliver benefits across customer service, asset management and network resilience. Over the past four years we have developed world leading network automation technologies to improve the reliability of supply to our customers. These systems automatically restore power to hundreds of thousands of customers every year and we are continuing to develop this technology.

At the heart of our innovation strategy is the principle of maximising the use of existing assets via innovative solutions to deliver greater value for customers. Whilst new technologies will be required to supplement existing assets we believe this approach is the key factor in delivering value across the entire service range. If it is possible to encompass our smart grid strategy in its most simple form it is to: "Reliably transport the optimum amount of energy through our network whilst ensuring the effects of aging assets are managed to deliver optimum service for our customers and value for Electricity North West and our stakeholders".

Our industry leading Capacity to Customers (C_2C) and Customer Load Active System Services (CLASS) projects, funded under the second tier Low Carbon Networks (LCN) Fund are examples of applying additional low cost smart technology to existing assets to maximise their utilisation. C_2C combines a revolutionary development in network management with innovative commercial contracts to maximise the amount of capacity available to customers, whilst CLASS aims to revolutionise network voltage management to deliver a demand response without customers being affected. The recently awarded eta project (renamed Smart Street) aims to transform the operation of the low voltage network enabling customers to quickly and cheaply connect Low Carbon Technologies.

We will invest over £26 million in innovation in DPCR5 and propose to invest at least £24 million in RIIO-ED1 that will deliver £133 million of customer savings in RIIO-ED1 and an anticipated £180 million in RIIO-ED2. We are seeking an innovation funding rate of 0.8%, equivalent to £3.0 million per annum, for RIIO-ED1. Our plan is detailed in this document, the main aim being to continue the preparation for the transition to a low carbon economy by developing tools, techniques and equipment that make more use of existing assets, already funded by our customers. As a single DNO we are not able to leverage group innovation funding ie multi DNO allowances. Whilst we will maximise use of other DNOs' R&D work, failure to secure the full 0.8% would place our business in a position of being unable to deliver the level of innovation benefits we have forecast in our business plan and hence increase costs to customers.

This document is for all our stakeholders. We'd welcome comments on any aspect of our innovation strategy and we will continue to seek stakeholder input into our innovation strategy and plans on a bi-annual basis as they are amended to reflect external influences through the period 2015 to 2023.

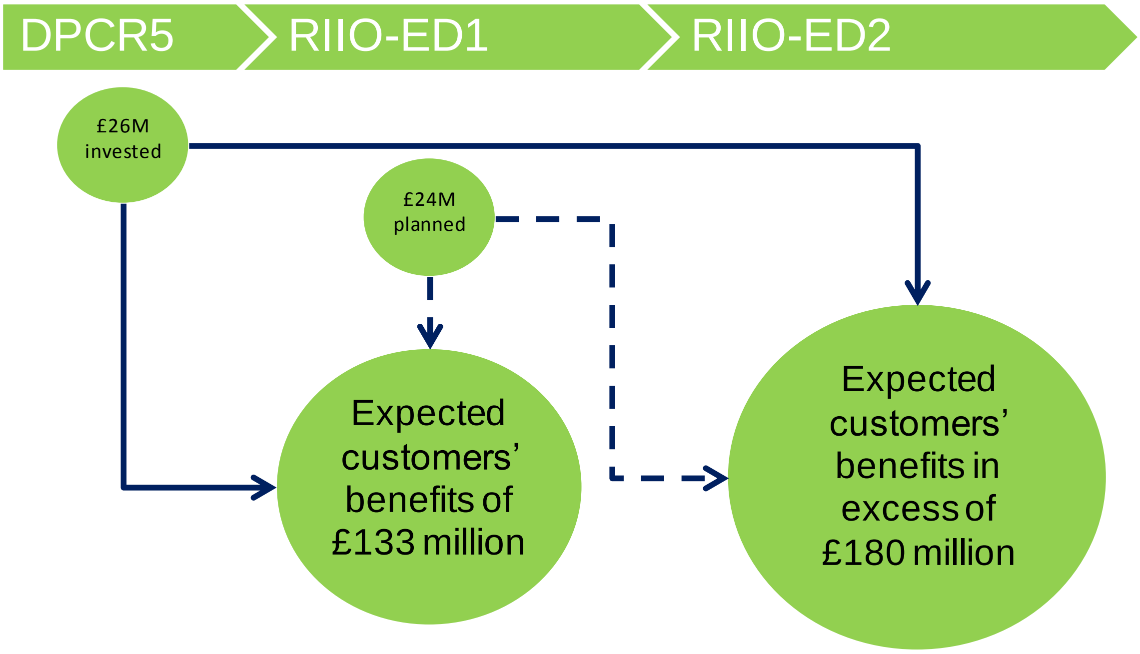
Steve Johnson, CEO

Contents

1. We are delivering benefits to our customers

In DPCR5 we expect to invest over £26 million in innovation, this combined with our innovation plan for the RIIO-ED1 period will enable us to deliver about £132.5 million of benefits for customers in RIIO-ED1 and predict to deliver in excess of £180 million benefits in RIIO-ED2. Figure 1 illustrates the customer savings that are directly enabled through our innovation plan. This is a significant return on investment.

Figure 1: Predicted customer savings from previous and future innovation spending compared against traditional techniques



Our work with stakeholders shows that their requirements centre around three consistent themes, namely reliability of supply, sustainability of operations and affordability of service. Figure 2 below shows diagrammatically their priorities centred on the key requirement of providing excellent customer service.

Figure 2: Our stakeholders' priorities

Our innovation plan is driven by these stakeholder priorities and our focus for the remainder of DPCR5 and RIIO-ED1 is split correspondingly into three broad areas which are illustrated below and described in more detail through a sample of case studies in the following sections.

Table 1: Key innovation themes

Affordable reliability	• Optimise the life of assets to keep costs down whilst maintaining reliability through refurbishment and monitoring.
	• Operate networks in new ways to deliver more capacity or value to customers though real time automation.
Customer Service	• Improve customer reliability through better understanding of macro asset performance and intervention timing.
	• Offer new services and choice to new and existing customers.
	• Keeping our customers better informed
Sustainability	• Enable customers to adopt low carbon technologies at an affordable cost.
	• Allow low carbon / renewable DG customers access to network capacity for less.
	• Reduce the carbon cost of our operations and investments

We are seeking an innovation funding rate of 0.8% for RIIO-ED1 which equates to an annual investment of £3.0 million on our innovation portfolio. This is a slight reduction in the level of investment we made in DPCR5 but above the default value of 0.5% for a licensed distribution network operator.

The reduced funding proposed in the RIIO-ED1 period is the result of two factors. First, we anticipate that more learning will be available from the wide range of projects being delivered by others or developed collaboratively with other partners. This allows us to identify and implement best practice solutions without the full cost burden of extensive research and development being passed on to our customers. Second, we have already funded a number of of innovations from the efficiencies they yield in our expenditure plans, such as Connect and Manage and our work on promoting energy efficiency. We will continue to utilise this approach in RIIO-ED1.

The additional 0.3% requested above the default value, which equates to £1.1 million per annum, is sought to fund the full scope of our proposed innovation programme; without this funding we will be unable to deliver the expected customer savings through RIO-ED1 and ED2. Over £50 million of customer benefits are at risk, which if the funding was not granted would increase costs to customers.

We also understand that we may not be able to predict the scale and complexity of future innovations. For larger scale innovations we will apply for additional funding through the Network Innovation Competition (NIC) with our partners. Plus we will seek funding from the Innovation Roll-out Mechanism (IRM) that will also allow us to deliver RIIO - ED1 innovations with our partners for our stakeholders. We are committed to sharing our knowledge and experience with other DNOs through our continued chairmanship of and contribution to industry forums and working groups.

2. Real value from innovation

Our customers should be confident that our innovation journey is aimed at continuously improving networks so that they are reliable, affordable and sustainable whilst delivering excellent customer service. In DPCR5 we have already shown that our innovation can deliver real performance improvements and benefits for our customers.

Innovation in reliability

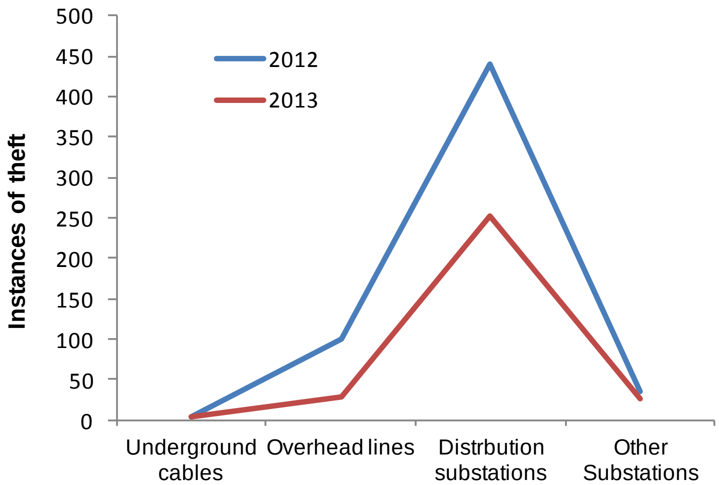
Knowing when to invest in replacing, refurbishing or retiring our assets has a fundamental effect on the reliability of our network and the quality of service experienced by our customers. We have developed best practice asset management strategies through the development and extension of Condition Based Risk Management (CBRM) and Condition Data Capture, which allows greater visibility of the health of our assets. Once we understand the health of our assets we can then determine the appropriate intervention and investment required. We have led the industry in pioneering this approach and it is now widely used and referenced by all DNOs.

CBRM helps us develop whole life asset management strategies based on analysis of current and expected future performance. We have invested £0.5 million in this initiative so far and have realised approximately £50 million in benefits through cost and delivery efficiency and scope optimisation. CBRM is now a business-as-usual activity and has played a major part in supporting our business plan.

We partnered with the University of Manchester to research the benefits of in-situ oil regeneration for our transformers. We can now regenerate transformer oil on-site through this pioneering technique, reducing the need for removal and replacement and significantly extending the operating lives of our transformers. Extending the life of existing transformers also has significant carbon benefits reducing the consumption of steel, copper and other resources. We have used the Innovation Funding Incentive (IFI) investment of £0.2 million to defer significant non-load related investment during RIIO-ED1. In RIIO-ED1 we plan to use this technique to avoid the replacement of over 12 Grid and 77 Primary transformers, which will save customers an estimated £33 million.

We have worked extensively with local police forces and specialist security advisors to develop a number of innovative techniques to complement more traditional security strategies in order to secure our network and reduce the number of customers suffering supply interruptions due to criminal activity. These initiatives have been successful in both stopping further increase in metal theft and in helping deliver a 46% reduction in theft instances.

Figure 3: Trend of instances of theft from distribution network



Examples of innovative techniques include:

- *Metal theft* – A marking system for copper earth tapes and cables that allows positive identification of the materials rendering them extremely difficult to dispose of without detection;
- *Active tracking* – New technology adapted from military applications where tracking devices are attached unobtrusively onto most types of substation assets and materials. The equipment can then be monitored and tracked when moved, allowing recovery from theft; and
- *New security measures* – A number of initiatives specifically targeted to limit the impact of theft at substations including a £3.2 million implementation of new electrical mechanical locking systems across 500 sites to prevent illegal access to secondary network substations.

Innovation in sustainability

We play a lead role in the Smart Grid Forum and development of the Transform model that is used by all Distribution Network Operators to quantify the needs and benefits from smart grid solutions. We have also used IFI funding to develop a more granular network capacity management model which we call our Capacity Headroom model. This model supplements Transform and allows us to understand how our customers use our network now and forecasts the future impact of adopting Low Carbon Technologies (LCT) such as electric vehicles and heat pumps on the LV network individual feeder-by-feeder level. Whilst this model tells us where our load carrying capability has to increase we also use it to more accurately target our future requirement for smart grid or network reinforcement solutions. This ensures that we can deliver low carbon solutions whilst minimising the cost of network reinforcement for our customers.

Our stakeholder engagement has clearly shown that in order for customers to adopt LCTs, the connection experience must be streamlined and simple. We have led the ENA heat pump and electric vehicle group to implement customer-friendly connections processes.

We have developed Demand Side Response (DSR) solutions to ensure we can support more sustainable technologies whilst maintaining reliability and affordability. DSR involves customers agreeing to shift their consumption patterns away from times of peak demand. This gives us more options to optimise network capacity and less reliance on reinforcement work. We have developed new technologies and commercial options under our Second Tier LCN Fund innovation projects to allow us to connect more renewable / low carbon generation and demand to our networks. These technologies will be developed further under our RIIO-ED1 innovation plan and we have included over £10 million of savings for customers in reinforcement costs through RIIO-ED1 under the DECC Low scenario.

Innovation in affordability

The cost of connecting to our network can be prohibitive for some customers. We have invested in the development of innovative commercial arrangements under our LCN funded Capacity to Customers (C_2C) programme to make this service more affordable.

New commercial arrangements allow customers to connect to the network using latent network capacity and offer voltage managed contracts for Distributed Generation customers. The real-time network voltage is used to control the use of existing assets, enabling us to minimise the connection costs of new generation connections. We are the first DNO to enter into these types of commercial arrangements with customers.

We recognise that developing solutions to address fuel poverty and help our vulnerable customers is extremely important. We have been working with a range of charities and government bodies to truly understand the issues around fuel poverty and how we as a DNO can make a positive difference. We have worked with Save the Children and National Energy Action (NEA) and have hosted a working dinner on fuel poverty with MPs from the North West at the Houses of Parliament. By focussing on the price impacts of every decision we have put together a business plan that proposes the largest reduction in distribution charges of any DNO to ensure we play our part in reducing fuel poverty.

We have implemented Connect and Manage strategies for low voltage domestic micro generation, such as solar panels. In Stockport we transformed our processes for connecting large numbers of solar panels on the roofs of social housing by introducing this Connect and Manage approach. This has reduced costs for Stockport Council considerably, as it negated the need for costly and time-consuming investigations into scenario and load planning. Instead, we simply connected all the solar panels, deployed inexpensive LV monitoring and dealt with a very small number of resulting problems. The trial was so successful that this Connect and Manage approach has replaced our existing process for all solar panel connections enabling benefits of lower energy costs and improved amenity in social housing across our network.

We are currently conducting a feasibility study with NEA and Stockport Council on an innovative project to upgrade their social housing stock and tower blocks to renewable heat. Rather than spending money to reinforce the local electricity network we have taken the innovative approach of improving the energy efficiency and insulation of the properties instead. The energy efficiency reduces the amount of energy required to run the properties and therefore reduces the need to reinforce our network. We will trial this approach later in the year alongside other techniques for reinforcement avoidance such as Demand Side Response. We and NEA believe that this sort of innovative approach not only saves money, and is environmentally friendly, but more importantly directly helps those most in need of support by reducing household energy bills.

Innovation in customer service

When we talk to customers they tell us that repeated supply interruptions are unacceptable. Analysis of the performance of our LV network revealed that transient cable faults produce many repeat faults and have a very significant adverse affect on our customers. These intermittent faults disrupt customers' supplies and often have no readily identifiable cause and can occur a number of times before the fault is localised and repaired.

To solve this problem, we have worked with Kelvatek, a UK technology manufacturer, to develop a number of devices such as the Modular Re-Zap (a unit that switches loads on low voltage networks) and the Bidoyng smart fuse (a device that can automatically restore customer supply in under three minutes). These devices have transformed the management of LV network cable faults. We will continue to implement this technology on our network and assist other DNOs by passing on our learning. Our initial £0.4 million innovation investment has resulted in over £2.3 million of price reductions on equipment purchases from our suppliers, a benefit that is passed on to our customers through cost reductions and more importantly improved supply reliability.

Almost 50% of the visitors to our website used a Smartphone or Tablet to access key pieces of information and over 25% of our website visitors access our website specifically looking for power cut information. With input from our customers we have developed a mobile friendly website that fits customer needs by giving customers accessibility irrespective of the mobile device they are using. This is ideal when customers are looking for information during a power cut and the use of a desktop personal computer is not an option.

In 2014 mobile internet use is expected to take over from desktop internet use, making this service crucial to enhancing our customers' interactive experience with us. Additional information on our track record of delivering customer value from our innovation projects is contained later in this document in the section titled "Our track record".

3. Innovation strategy

3.1 Why innovate?

Innovation is one of our core values and we are leading the industry in developing innovative solutions that challenge and improve the way we do things and deliver savings for our customers and stakeholders. This is our culture; it's about continuous improvement in everything we do to deliver our commitments of customer service, affordability, sustainability and reliability for our network services. Innovation is a good way of ensuring that customers continue to enjoy a value for money service. As we have demonstrated during DPCR5, modest amounts of investment in innovation projects can when successful realise material savings to customers.

Innovation funding is therefore essential to allow this work to continue and for the associated benefits to be realised by our customers and stakeholders. Innovation creates many benefits across customer service, reliability and cost reductions, depending on the nature of the benefit some are shared with customers and some accrue solely or in the main to customers. For example reductions in investment volumes, through transformer regeneration or CBRM accrue directly to customers. Other examples include Connect and Manage or new connection techniques that reduce connection charges. Where we do not receive a material share of the benefits then without innovation funding we would therefore be unable to fund the developments necessary to achieve these improvements. Some areas of innovation create shared benefits, for example network supply restoration automation. In such instances where our share of the benefits enables us to fund the work we have not requested innovation funding, this is a continuation of our policy in DPCR5. Where the benefits are shared but insufficient value accrues to enable us to fund the work we have included costs in our innovation plan to allow customers to receive the benefits.

There are significant challenges from transition to the low carbon economy, so we have a Future Networks team, within our Network Strategy directorate, focussed on finding value for money innovative solutions to these problems. We see our relationship with customers changing as we develop and offer innovative technical and commercial solutions. As we start to provide greater choice to customers and in some instance seek services from customers we will become a smarter network operator and take the first steps towards becoming a distribution system operator.

We have a demonstrable track record of delivering smart grid solutions targeted at key issues that affect our customers and network. Examples include:

- the installation of the first UK network demonstration of a super-conducting fault current limiter, which allows fault level constraints to be managed without resorting to traditional expensive switchgear replacement,
- Connect and Manage approach to the installation of micro-generation to the LV network;
- the development and deployment of the smart fuse, aimed at enhancing customer service by eliminating a high proportion of transient fault interruptions; and
- first UK installation of capacitors to the LV network for voltage regulation and optimisation.

These projects were designed to deliver real benefits to customers that could be measured and compared with traditional approaches. In addition to these, we have delivered a number of projects that have had measurable benefits for customers such as voltage control monitoring and finding ways of connecting the increasing DG without incurring reinforcement. We have delivered high levels of 'Connect and Manage' connections, facilitated through finding innovative approaches. Our work on design standards for smart grids shows that it is not in the interests of customers to always design for network extremes; rather we should operate for anticipated conditions that appropriately balance risk and infrastructure. As a part of introducing new techniques such as DSR we have most recently through our C_2C project proposed revised guidelines in ETR130 for the management of DSR. Allied to this, we have used our leadership in the ENA and in the Distribution Code Review Panel to initiate a fundamental review of the ENA Engineering Recommendation P2/6 Planning Standard.

We believe innovation in standards will continue to be a consistent theme throughout the remainder of DPCR5 and ED1. Our challenge of and leadership in the development of European codes and the evolution of GB standards will continue as a means of delivering additional value and security for customers.

3.2 Innovation principles

Our continuous improvement journey is led by the needs of our customers. Our approach to innovation is described in the three guiding principles we apply when considering innovation:

1. We aim to understand and respond to the changing needs of customers;
2. Collaboration with partner organisations find innovative solutions; and
3. Involving customers in our innovation work ensuring potential innovative solutions deliver customer benefits.

Before committing funds to a project we validate that the technology is likely to be economically viable and that the problem is within the timescale of our business plan. This ensures that we focus on projects most likely to deliver actual value to customers in the near to medium term. Whilst we do support technology that has a very long term development period such as storage, we do this through collaboration with other DNOs through the Energy Innovation Centre and EA Technology's Strategic Technology Programme. We chair EA Technology's Strategic Technology Programme.

Where appropriate, we have drawn upon the work of other DNOs to inform and enrich our own work:

- WPD's LV network templates have been of considerable assistance in our work on LV network solutions;
- Previous work by UKPN on network meshing and LV sensors has informed our view on micro DG connections;
- We have also drawn upon the work of Scottish Power Energy Networks in Active Network Management to inform our strategy on network balancing automation;
- Our work with National Grid on the strength of DSR signals from industry participants was instrumental in the formulation of our DSR projects and load-related business plan;
- We also note the work of Smarter Grid Solutions with Scottish and Southern Energy, amongst others, on DG scheduling integration into control room operations; and
- We have also worked collaboratively with other DNOs on the development of the Transform model which contains the cost benefit analysis for all known smart solutions; we used Transform to price our load related investment plan including this additional value for customers in our business plan.

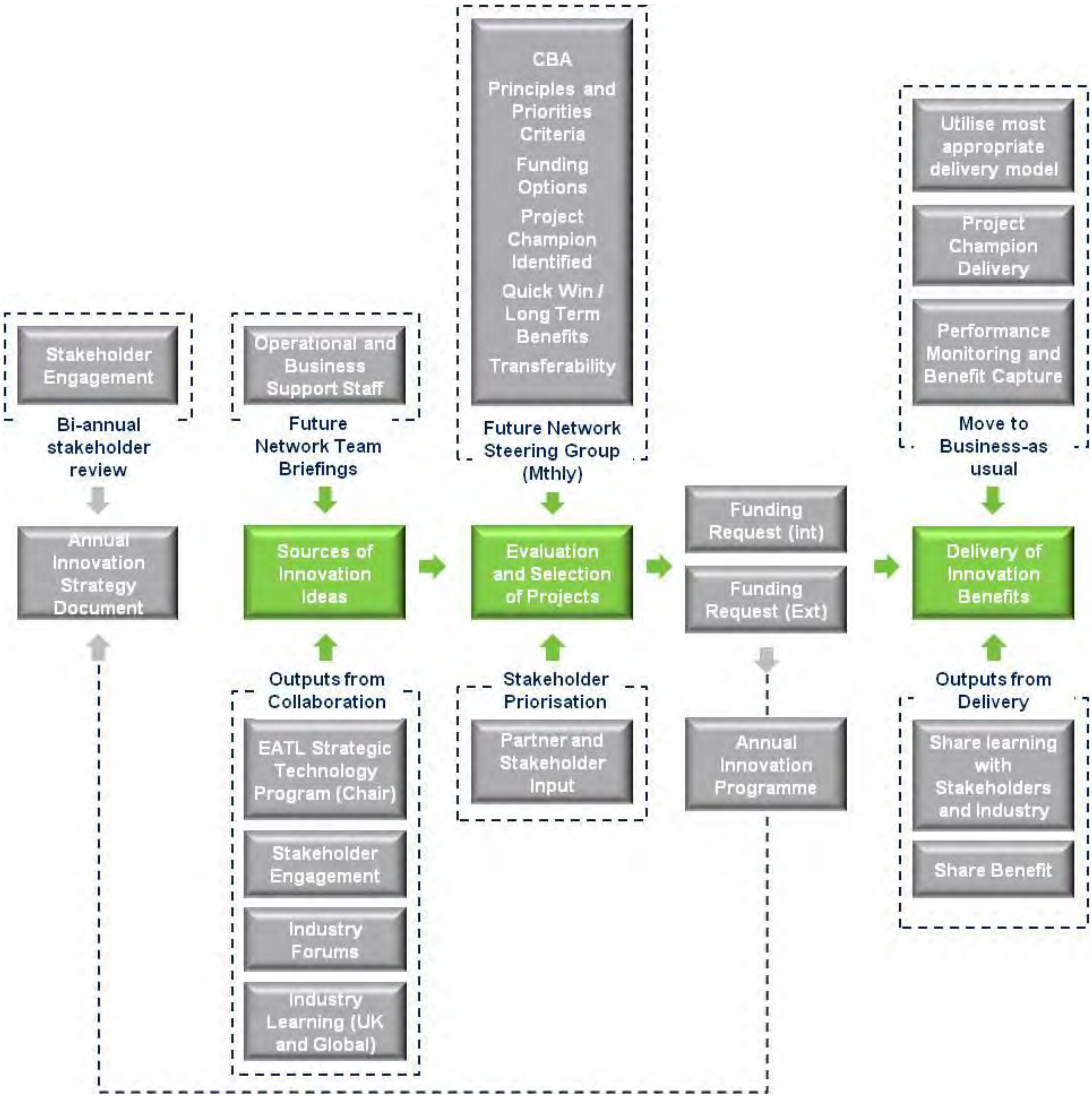
It is clear that the value arising from collaborative work on smart grids and smart meters is significantly greater than that which could be achieved in isolation.

3.3 Innovation governance

We apply robust governance to the process for identification, selection and delivery of innovation projects. Our Future Networks Steering Group, which is co-chaired by our Network Strategy and Regulation directors, is responsible for setting and overseeing our portfolio of innovation projects; whilst our Future Networks team is responsible for driving forward the innovation programme and managing the creation and delivery of innovation projects with partners.

Figure 4 overleaf shows the process for sourcing ideas, developing projects from the ideas, and evaluating and selecting projects, as well the process for transitioning innovation solutions into business-as-usual. This process has been developed to ensure our investment in innovation is tested and validated and the impacts understood prior to rolling out as a business-as-usual activity.

Figure 4: Governance process for innovation programme



We recognise that innovative ideas can come from diverse sources so the Future Networks team regularly engage with managers and teams from across the business and engage with partners eg manufacturers, academics etc and attend industry groups to listen to their issues and ideas and understand technological developments and bring these internal and external views into one place within the business.

An idea is developed into a project, including a business case, which describes the aims, objectives and expected outcomes and where in the development cycle the project is positioned therefore aiding the selection of the innovation funding source. Each project is then grouped within an innovation theme and the Future Network Steering Group will then evaluate the project against the innovation strategy and programme. If approved the project forms part of the innovation programme and is delivered with monitoring its progress against timescales, budget, objectives and outcomes on a monthly or quarterly basis. These combined processes give evaluation at a project level and provide oversight at a programme level to deliver the expected outcomes.

Our innovation strategy and the associated innovation programme are approved annually by the Future Network Steering Group. The portfolio of innovation projects is continuously under review as projects are created and submitted for funding monthly. Our Innovation strategy will be updated bi-annually with input from stakeholders via consultation.

3.4 Managing uncertainty risk

Innovation projects by their very nature contain risk in terms of funding requirement, timing and technology / commercial success. All of our projects are managed in accordance with Prince 2 project management principles with progress against all KPIs being reported monthly to our Head of Future Networks and Future Networks Steering Group.

Risk management on innovation work is more challenging than traditional projects due to the delivery uncertainty from the low technology readiness levels versus business as usual. It is therefore critical to manage this risk so as to use customers’ money wisely. To this end, risk is considered from the project concept stage where we ensure that the project is designed to deliver a clear outcome whether that is a specific piece of learning, a device or technique. This focus allows us to tightly contain the scope of the project and exclude non value add tangential areas of work which are not strictly necessary and would simply add risk and cost.

Once designed the project is subject to a robust sign off process including:

- Review by the Head of Business Finance to test the validity of the business case and the contribution of each work module to the learning;
- Review by the Head of System Control to validate the operational acceptability of the technique and to approve commitment of field staff resources where required;
- Review by the Head of Future Network to ensure sufficient resources are available to deliver the project objectives, it does not duplicate work by other DNOs and the learning is valuable and transferable to our stakeholders; and
- Finally review by our Network Strategy director to ensure fit with our innovation strategy and innovation programme.

There is uncertainty in the outcome for each innovation project, irrespective of whether it is in the research, development or deployment phase. We have oversight at the programme and project level through the monthly Future Network Steering Group meetings and recently we have enhanced the internal governance and risk management approaches specifically for managing the uncertainty risks associated with delivering innovation projects.

By careful design at the concept stage we have £20 million of Second Tier LCN Fund projects in flight and have successfully delivered against every single project milestone.

3.5 Stakeholder engagement

We are able to articulate the network problem and we use strategic partnerships to generate a range of hypothetical solution options which will solve the problem and stakeholders' input to help us decide which solution option to adopt. For example in the development of our Connect and Manage approach we approached a range of stakeholders; and specifically in the case of clustering of solar PV we consulted all those affected by our proposals, including the local authority, the Registered Social Landlord (Stockport Homes) and the installer; and in the case of voltage managed connections we discussed this proposal with the generation developers active within Electricity North West's area, including their trade associations.

Throughout RIIO-ED1 and beyond we will consult formally on our innovation strategy on a bi-annual basis allowing our stakeholders to comment on the direction of travel and the range and type of innovation projects. The consultation on our innovation strategy will form part of the wider stakeholder engagement planned throughout the RIIO-ED1 period.

3.6 Transition to business as usual

Managing the transition of an innovative solution based devices, technology or new operating arrangements into business as usual is the most important stage in delivering benefits to customers. To ensure we are successful we develop innovations from a low technology readiness level using IFI funding to test components or concepts, we then use First Tier LCN funding where necessary to conduct small scale live trials and where necessary utilise Second Tier LCN funding to conduct large scale tests, measure customer acceptability and develop the codes of practice, operational policies and procedures required to deploy as business as usual.

A recent example of this approach in practise is the Smart Street project, where:

- Early development of the concept and manufacture of the low voltage vacuum circuit breaker were funded by IFI;
- Work under our First Tier LV Network voltage project tested the voltage control devices in our networks and developed policies and procedures for their deployment; and
- In the Second Tier project only actual deployment at scale was funded.

Throughout the life cycle of the IFI and First Tier projects the project manager and Steering Group regularly reviewed progress and confirmed that the objectives are both still valid and attainable.

If any project is unlikely to deliver benefits due to say technology difficulties or the emergence of a more favourable approach then it is reviewed and where necessary stopped. An example of this would be the line tracker device originally developed collaboratively through the EIC which was overtaken by new commercial products from manufacturers.

3.7 Knowledge transfer

We have taken a proactive role sharing knowledge with other DNOs through the development and delivery of the annual LCN Fund conferences and taken every opportunity to attend learning and dissemination events hosted by other DNOs. A specific example of knowledge transfer into Electricity North West is the adoption of a low voltage circuit breaker developed by Tyco Energy for UKPN under a First Tier LCN Fund project that is being used as part of our own low voltage automation project.

We have also hosted events for our C_2C and CLASS projects, and we see these events as being important for knowledge transfer through the remainder of DPCR5 and into RIIO-ED1.

When thinking about knowledge transfer we involve our project partners, suppliers and even our trial customers in our dissemination events. We attend supplier trade conferences to explain our work and regularly hold briefings with our local companies on particular techniques or technologies. We utilise a wide range of dissemination techniques in addition to presentations to share the learning from our projects; we have successfully delivered Webinars, created Video Podcasts and video materials and posted them through social media channels in addition to the standard production and publication of formal white papers. Our website (www.enwl.co.uk/the-future) is the repository for sharing information, learning and knowledge created from our innovation projects.

We will continue to find new ways to share knowledge with our stakeholders. In choosing our audience we go beyond other network operators, targeting our customers, academia, manufacturers, energy suppliers, DECC and a number of trade bodies and stakeholders, such as BEAMA. These parties are all part of the overall technology adoption plan and hence critical to delivering on our commitment to share innovation opportunities with others throughout RIIO-ED1 and ED2.

4. Challenges which Electricity North West is facing

4.1 Understanding the potential challenges within RIIO-ED1 and ED2

In addition to the day-to-day challenges faced by Electricity North West, there are longer term challenges common to all UK DNOs. The challenges are not just climate change, they alos include security of supply and fossil fuel energy costs. . The following challenges are detailed as:

1. Climate and energy landscape
2. Increasing customer expectations
3. Economic climate
4. Ageing assets

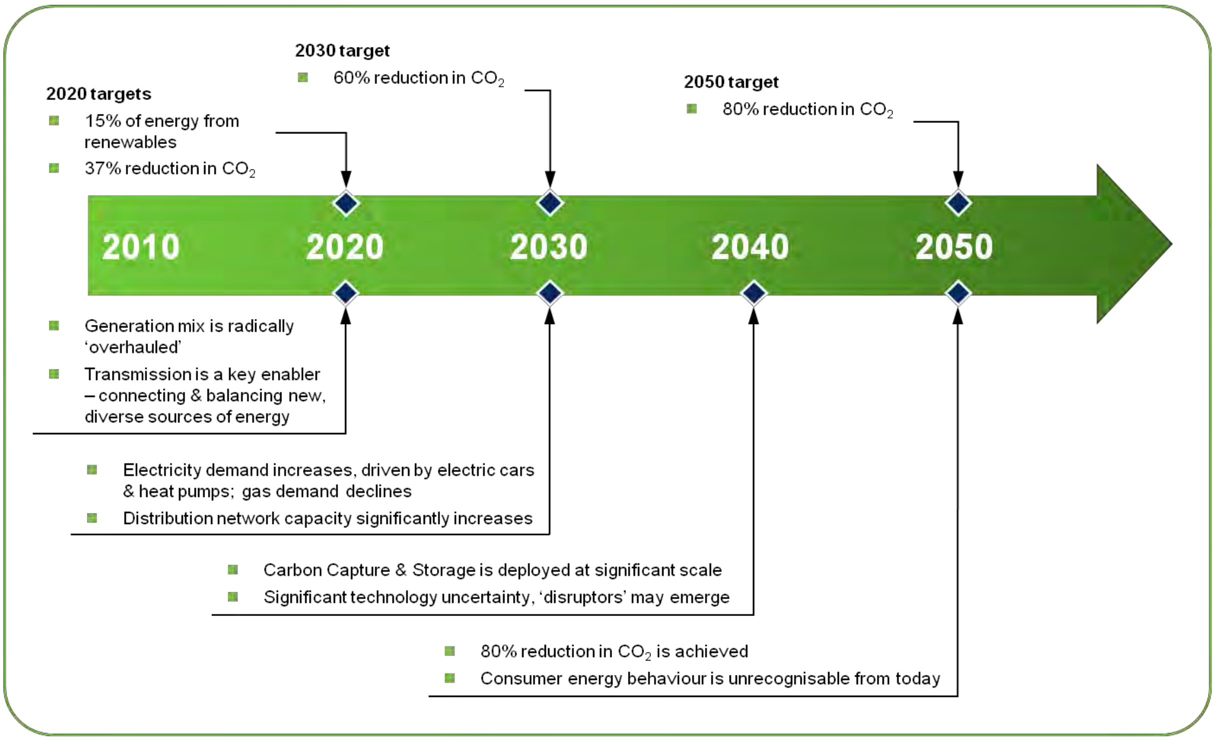
The role of UK electricity distribution network businesses has traditionally been asset centric, providing a secure and reliable service to the homes and businesses of the UK. With the advent of the fourth carbon budget, the industry is now facing one of its biggest ever challenges and needs to adopt and manage radical changes to ensure we can play our part in the migration to an affordable low carbon economy.

Climate and energy landscape

According to the DECC Energy Roadmap[1] published in July 2011 to meet the requirements of the fourth carbon budget, the key challenge for electricity distribution networks within RIIO-ED1 will be the connection of additional renewable energy distributed generation (DG). Our network already has DG equal to over 50% of maximum demand and networks in areas rich in renewable resources such as wind are already at saturation point.

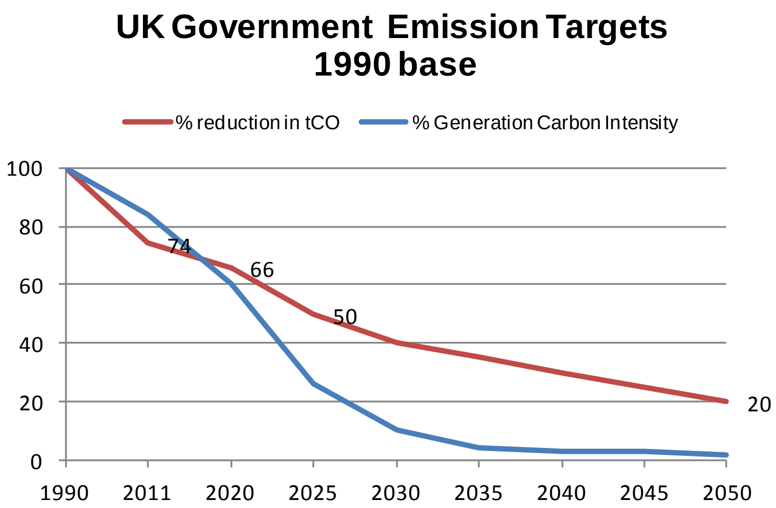
[1] http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/re_roadmap/re_roadmap.aspx

Figure 5 – UK energy roadmap



As can be seen from Figure 6, the projected rate at which the energy generation sector is to decarbonise (or the rate at which renewable energy generation is to replace fossil fuel plants) needs to accelerate over the next ten years to meet both emission reduction targets and large combustion plant directive[2] commitments.

Figure 6: Rate of decarbonisation of energy



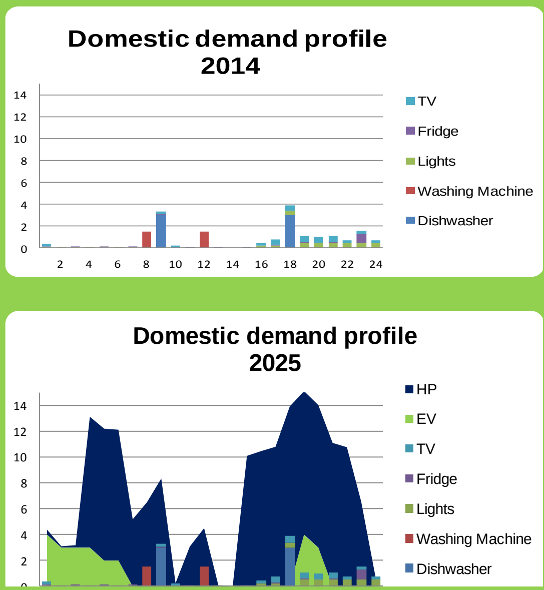
The intermittent nature of several leading renewable energy generation technologies (in the absence of mass market ready storage) has the potential to radically de-couple the link between maximum demand and prices paid to generators. For example the highest prices are now paid to generators at times of peak demand but if a significant amount of wind energy were to be available during peak demand period then obligations to purchase

2 http://eur-lex.europa.eu/LexUriServ/site/en/oj/2001/l_309/l_30920011127en00010021.pdf

renewable energy over fossil fuel generated energy could result in unpredictable fluctuations in wholesale energy prices. This phenomenon has already been observed in Ireland with one of the richest wind energy resources in Europe where the emergence of wind following in pricing has resulted in suppliers and the TSO placing price signals into the market at time of peak demand forcing even more demand onto already congested networks.

One of the greatest challenges facing network operators is the future customer adoption of devices such as PV micro generation, heat pumps and electric vehicles fed from legacy networks. Incentives schemes have driven the introduction of intermittent generation on networks where it was never originally envisaged. installed on our LV network. The Renewable Heat Incentive is also expected to drive a similar level of customer activity leading to substantial additional demand from heat pumps.

Figure 7: Forecast changes to domestic demand profiles



As an example, solar PV feed-in tariffs introduced in 2011 resulted in a number of significant clusters of panels The majority of our customers are domestic and are fed from our secondary LV networks which for many years have followed predictable and stable demand domestic customer in 2012 and 2025 are contrasted in Figure 7 which graphically shows that the adoption of devices such as heat pumps and electric vehicles by customers will change the daily loading patterns and magnitude of their power consumption. Our domestic demand is expected to grow from 3GW to around 6GW by 2050 even with optimal scheduling. 20% of this growth is forecast to occur by 2023. To meet UK government targets some 700,000 domestic heat pumps will be fitted by 2030 adding 2 GW to our demand.

31% of the UK's 12 million vehicles are forecast to be EV/hybrid by 2030. For Electricity North West this equates to some 720,000 domestic EVs and 80,000 e-vans charging from our network adding ≈ 2GW to our demand.

By 2050 the charging demand of EVs in Manchester could exceed the city's present electricity demand of 400MW.

Increasing customer expectations

The adoption of low carbon technologies will mean that customers increasingly derive their heat and transport energy needs from electricity networks and hence the reliability of supply will be ever more critical. It simply will not be acceptable for customers to lose electricity supplies for protracted periods when homes and businesses are heated by electricity and electric vehicles are in common use. Delivering ever higher reliability levels from an ageing asset base will require innovation in network management, energy management, active automation systems, fault detection and repair technologies. Customers will also require improved information on any network outages and enhanced support.

Economic climate

The general economic challenge facing the UK coupled with sustained rises in raw fuel prices is leading to increased concerns regarding fuel poverty amongst customers. Figures published by DECC[3] show that between 2004 and 2009 domestic electricity prices rose by over 75% leading to a 5% rise in fuel poverty. These figures further indicate that over this same period electricity prices rose faster than income levels. Although distribution network costs are only a small element of the final bill paid by customers the pressure has never been greater for network operators to reduce costs and increase efficiency. Smart grids will play a critical role in enabling efficiencies across the whole range of network operator activities.

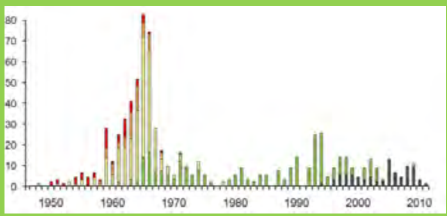
Ageing assets

DNOs manage an increasingly ageing asset base with many of our assets now approaching their traditional end of life.

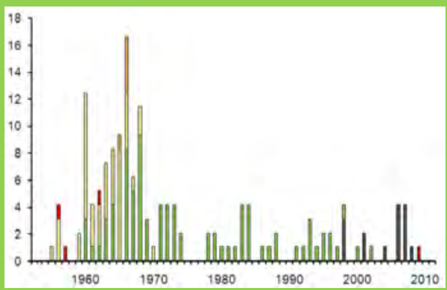
Even if it were possible to fund the replacement of these assets according to their age profile the scale of the replacement programme would be prohibitive. To improve the management of such assets and keep costs down for customers, we pioneered the industry move to Condition-Based Risk Management (CBRM) strategies. These strategies have resulted in a much more informed understanding of assets allowing their lives to be extended whilst managing risk to customers. CBRM will continue to evolve as we develop new techniques for assets such as large power transformers, switchgear, protection and civil assets. Innovation in these asset management techniques is vital to enable assets to be safely managed well beyond their design life. We are leading several major projects seeking to both better understand asset reliability and increase their load carrying capacity. Whilst such projects focus benefits on individual assets they are further enhanced by our belief that the development of criticality analysis techniques is a key component in the evolution of smart grids to ensure risk and commercial positions are appropriately balanced. These compatible technologies allow large populations of assets to be more efficiently managed with risk and investment better targeted for the benefit of customers.

Figure 8: Age Profiles

Age profile of 33kV transformers



Age profile of 132kV transformers



4.2 Challenges aligned to RIIO-ED1 framework

In our guiding principles we explained that our work plan is geared to the needs of customers in the short to medium term; specifically in the periods RIIO - ED1 and ED2. Our work with Cambridge Economic Policy Associates (CEPA) and Tyndall Centre at University of Manchester has shown that that the DECC Low scenario[4] is the most appropriate base case

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3 http://www.decc.gov.uk/en/content/cms/statistics/fuelpov_stats/fuelpov_stats.aspx

4 Need reference to the correct Annex in WJBP

for the RIIO-ED1 period. Table 2 below describes the challenges and the associated symptoms we will see over the next 10-15 years under the DECC Low scenario grouped under the innovation themes of Networks, Carbon & Social and Customers.

Table 2: Symptoms of the challenges faced by Electricity North West in RIIO-ED1

Affordable reliability	Adoption rates for LCTs driving Network loads beyond existing capacity coupled with ageing infrastructure and a need to improve reliability of supply.
	Continued unpredictability in economic growth in the region
	High levels of DG necessitating optimisation of output or alternative methods for the storage of excess energy and greater flexibility in network loading and capacity
Customers	Customers demanding greater transparency over the way in which they are charged for electricity and more control over their own electricity consumption
	Demands for improved quality of service
	Extensive smart meter roll-out
Sustainability	Greater demands for electricity as more customers switch from gas
	Domestic use increasing by up to 20% through the connection of Low Carbon Technology (LCT) to the network
	Continued upward pressure on energy prices

Meeting these challenges with traditional techniques is unaffordable to UK energy bill payers and so to mitigate these costs we are maximising the utilisation of the existing assets through the incremental installation of new and smart technology along a path to create a smarter distribution network.

In table 3 below the challenges faced by DNOs are linked in matrix format to the priorities of our stakeholders and our innovation themes; this shows that our innovation themes map to the challenges faced and the expected outputs link directly to the key priorities identified by our stakeholders and the Ofgem outputs. This provides us with reassurance that the identified challenges aligned with the RIIO-ED1 framework.

Table 3: Innovation strategy linked to challenges and stakeholder priorities

	Challenges			
	Climate and energy landscape	**Increasing customer expectations**	**Economic climate**	**Ageing assets**
Ofgem Outputs				
Reliability and availability	●	●		●
Safety	●	●		●
Social obligations	●	●		●
Environmental Impact	●	●		●
Customer Satisfaction	●	●	●	
Connections	●	●	●	
Stakeholder Priorities				
Reliability	●	●		●
Sustainability	●	●		
Affordability	●	●	●	●
Customer service		●		
Initiative themes				
Affordable reliability	●			●
Sustainability		●		●
Customer Service	●	●	●	

5. Our response to the challenges

5.1 Understanding how the future challenges manifest themselves

The challenges outlined in the previous section manifest themselves as a range of network problems that in the past would have been solved using traditional techniques, namely investing in more assets.

The technical and physical attributes of these challenges are identical to those observed today as the physics of electricity has not changed. For example increased load requirements from a group of domestic customers will create thermal and/ or voltage issues as the capacity level of network assets are met and in some cases exceeded; or the proposed connection of a new generation facility will potentially exceed the fault level capability of the local network assets.

But the potential solutions to these challenges need a different approach utilising the latest commercial and technical innovations. Our aim is to facilitate our customers' aspirations and to do so in a manner which is in most instances unseen. Where customer interaction is necessary our aim is to make it simple as we want to avoid hindering their choices or delaying them meeting their aspirations. We aspire to deliver a reliable, sustainable and affordable service to our customers who know we are there to help them and trust us.

Therefore we must understand the scale and timing of the challenges. This means we must anticipate the expected quantities and the expected speed of adoption; recognise that some development will occur in clusters but the majority will occur randomly across the network; and develop the retrofit equipment and techniques to rapidly upgrade the network.

Climate and energy landscape

International agreements were reached through the United Nations Convention on Climate Change that committed developed countries to reduce their emissions of greenhouse gasses with the aim of "stabilisation of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system"[5]. These international agreements to act on climate change were translated into EU commitments through a range of different mechanisms and in the UK resulted in the 2008 Climate Change Act which created a legally binding target to reduce the UK's emissions of greenhouse gases to at least 80% below 1990 levels by 2050. In addition to the binding emissions targets, the Committee on Climate Change, an independent body of recognised scientific and technical experts, was also created. Its remit is to inform and drive government policy enacted through the Department of Energy and Climate Change. This advice takes the form of a number of reports and 'carbon budgets' which are in effect the limit on the amount of carbon emissions permitted on the path to 2050 to achieve the agreed targets. The first three carbon budgets were released in 2008 and set the level and pace of emission reduction to set a ceiling on emissions of greenhouse gases in the UK for the three periods 2008-2012, 2013-2017 and 2018-2022. They also promoted a range of measures to achieve a path to the 2050 target. The fourth carbon budget was enacted by secondary legislation in May 2009, passed by Parliament in June 2011 and set the pace of emission reduction for the period 2023 to 2027.

Two recommendations were made that have a specific impact on Electricity North West:

- Electricity Market Reform which aims to add 30-40GW of low carbon generating plant by introducing new arrangements to promote competitive tendering of long-term contracts for investment in low carbon capacity; and

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[5] *The United Nations Framework Convention on Climate Change.* http://unfccc.int/essential_background/convention/background/items/1353.php. Retrieved 15 November 2005.

- Funding and policies to support development of technologies and new markets, key technologies being demonstrated now for deployment in the 2020s including carbon capture and storage in power generation and industry, electric cars and vans, and electric heat pumps.

As part of its ongoing commitment to these internationally agreed targets on greenhouse gas emissions reduction, the UK government has launched a number of initiatives on energy efficiency, carbon costs, renewable energy generation and electric vehicle incentives. All of these coupled with a general increase in awareness of 'energy' issues are expected to impact significantly upon electricity consumption in terms of patterns and overall levels.

The key challenges for electricity distribution networks within RIIO-ED1 will be the connection of additional renewable energy distributed generation (DG). Our network already has DG equal to over 50% of maximum demand and networks in areas rich in renewable resources such as wind are already at saturation point. As an example, solar PV feed-in tariffs introduced in 2011 resulted in a number of significant clusters of panels installed on our low voltage (LV) network leading to the presence of intermittent generation on networks where it was never originally envisaged. The Renewable Heat Incentive is also expected to drive a similar level of customer activity leading to substantial additional demand from heat pumps. One of the greatest challenges facing network operators is the future customer adoption of devices such as PV micro generation, heat pumps and electric vehicles fed from legacy networks.

Commercial mechanisms such as demand side response (DSR) and generation side response (GSR) are key commercial components of smart grids and will play a pivotal role in helping network operators meet these challenges. We have been consistently at the forefront of DSR development and usage, and were the first UK DNO to sign such contracts to defer reinforcement. We continue to innovate in this area with our C_2C project which seeks to introduce new forms of low intrusion DSR/GSR contracts for customers to both stimulate the embryonic DSR market and dramatically reduce connection costs to customers. We can also expect to see a stronger market within RIIO-ED1 for DSR and GSR across the supply value chain with demand and generation response being used to simultaneously balance networks, system frequency and commercial positions.

Our research work with Pöyry and National Grid clearly illustrates the relative strengths of DNO, TSO and Supplier balancing signals and the dominance of the latter two in current commercial trading markets. DNOs must therefore find new ways of balancing their networks both technically and commercially. Our C2C and CLASS projects are specifically designed to respond to this challenge by unlocking significant additional capacity from existing network assets and offering flexible network management tools to DNOs. Our work to date on smart grid DSR has been successful in securing a number of major DSR customers who have already begun to realise the benefits of smart grid solutions for their own cost base and will act as flagships for other commercial customers.

We believe that the above complexities, coupled with the increasing demands placed on networks in RIIO-ED1 will necessitate the emergence of DNOs as distribution system operators (DSOs). Whilst the full scope of DSO services is yet to emerge, what is clear is that DNOs will need to embrace a wide range of smart meter data services and smart grid technologies such as energy management systems to meet customers' future needs.

The current structure of electricity transmission, distribution and supply has been based on being able to balance demand with supply in real time. This is achieved by both being able to reliably predict forward demand based on a range of known factors and being able to call on highly controllable fossil-fuelled generation at times of high demand and fast acting reserve generation for short term peaks in demand. Historically, long term investments in generation capacity could be made due to a predictable understanding of forward prices and fuel costs, however, the way in which future electricity will be generated will require this approach to be radically changed. As can be seen from Figure 6, the projected rate at which the energy generation sector is to decarbonise (or the rate at which renewable energy generation is to replace fossil fuel plants) needs to accelerate over the next ten years to meet both emission reduction targets and large combustion plant directive[6] commitments.

Projections for domestic customer load growth have upper and lower projected limits but it is clear that to facilitate the migration of heat and transport to a low carbon economy, electricity network loads will increase. New commercial and technical solutions will be required to mitigate the potentially prohibitive cost to customers of traditional reinforcement-based solutions.

Figure 9 – DECC projections for increasing domestic load

Peak domestic electricity demand increases significantly...

≈2.5kW peak appliance demand for an average house

\+ ≈3kW charge for an electric car

\+ ≈8kW demand for a heat pump

= ≈10-12kW potential total demand

Distribution networks may need to more than double their capacity...

	2010	2030	2050
Household demand*	≈2.5kW	≈4.7kW	≈7kW
Number of homes	26m	31m	36m
Embedded generation	≈8GW	≈15GW	≈20GW
Network loading (kW/km)	≈75	≈170	≈300
Network scale		X2.3	X4.0

* After diversity average peak demand

Network scale vs 2010 levels

The majority of our customers are connected via typical LV networks which have been historically designed on a ‘fit-and-forget’ basis to accommodate a narrow range of loading conditions based on an average demand taking into account the diversity of customer activity. Our work has shown that whilst the performance parameters of these LV networks are not currently fully understood, there are significant opportunities to operate them in smarter ways to increase the capacity available for existing assets.

This will involve new operating regimes, real time sensing technologies, advanced network modelling and simulation techniques and the challenging of historic standards. Our Smart Street project has been born out of this challenge and incorporates LV network meshing technologies, active voltage management and conservation voltage reduction. This project will deliver direct cost reductions to customers through reduced energy charges, reduced DUoS charges and higher FiT revenues.

Economic climate

We have seen domestic electricity prices rise by over 75% between 2004 and 2009; and this trend is expected to continue as GB develops low carbon and/ or renewable generation as

[6] http://eur-lex.europa.eu/LexUriServ/site/en/oj/2001/l_309/l_30920011127en00010021.pdf

part of the plan to reduce its carbon footprint. UK energy bill payers will face increasing cost pressures, so network operators must innovate to help reduce these energy costs and increase efficiency. Smart Grids will play a critical role in facilitating efficiencies across the whole range of network operator activities.

Increasing customer expectations

We know from our stakeholder engagement in DPCR5 that our customers believe repeated supply interruptions are unacceptable; and so part of innovation programme in DPCR5 has been focussed on fault location and management – this will continue and accelerate in RIIO-ED1. As we anticipate that as customers become more reliant on electricity for their heating and transport needs then their expectations of resilience and reliability will increase. Part of the RIIO-ED1 innovation programme aims to develop the tools, techniques and equipment to operate our network in a manner making it more reliable.

With the general capability increase of mobile IT and handheld devices within domestic premises we anticipate that customers expect to access Electricity North West's services through both real and virtual channels; and when loss of supplies do occur our customers expect to be provided greater information through these real and virtual channels. Our innovation programme will look how to deliver these services using information retrieved automatically from our systems and packaged up for the customers.

Ageing assets

As the owner and operator of a significant asset base that provides a vital service to our customers it is critical that we employ cost effective tools and techniques that manage the assets and keep costs down for customers. Our pioneering move to Condition-Based Risk Management has resulted in a much more informed understanding of the assets. We will continue to develop CBRM techniques to enable assets to be safely managed well beyond their design life. This work seeks to better understand asset reliability and develop criticality analysis techniques to ensure the operating risks are understood and appropriately balanced.

These developments will enable asset solution investment and commercial service solutions investment be better targeted for the benefit of customers.

5.2 Phased approach to delivering innovation initiatives

We have broken down the key innovation areas of focus across the three time periods of DPCR5, first half of RIIO-ED1 (2015 to 2019) and the second half of RIIO-ED1 (2019 to 2023) as we develop incrementally the smart distribution networks to meet our customers' changing needs.

For example the early years of RIIO-ED1 will focus on extending the smart grid capabilities we are developing in DPCR5; for example LV network automation, active voltage control and extracting value from the network and customer data generated thereby. We will also commission a replacement network management system in this period, which will unlock additional system capacity from the wide scale deployment of C_2C, CLASS and Smart Street, which are also being developed as projects in DPCR5. The new network management system will also provide the foundation for extracting value for customers from smart meter data in the later years of RIIO-ED1, whilst we start to develop our understanding of the future transition from an asset centric distribution network operator to a distribution system operator.

6. Our track record

We are one of the few DNOs to have successfully spent their DPCR5 IFI funding of £2 million per annum. The success of our LCN Fund and IFI-funded initiatives means our customers will share in around £63 million of savings which we will deliver by the end of DPCR5. Table 4 below the right highlights our funded innovation projects and the benefit delivered in DPCR5 and projected for RIIO-ED1.

Table 4: Range of innovations undertaken in DPCR5 delivering value for customers and stakeholders

Stake-holder Priority	Innovation Initiative	Funding Type	Project Cost	Benefit	Saving Projection DPCR5	Benefit/ Saving Projection RIIO ED1
Customer	**Network Operation** - Development of a time domain reflectometry approach to LV fault finding	IFI	£7,000	Delivers faster repairs with less time and excavations to locate the fault saving repair costs and CML	**£3.6m**	**£14.4m**
	Network Operation - Delta V Developments & Trial - Development of a voltage gradient approach to LV faults finding	IFI	£63,000			
	Network Operation - Modular/Master Slave Rezap - Development of an LV autorecloser that will fit into all ENWL's LV fuse pillars and boards	IFI	£316,000	Reduces impact of transient faults by autoclosing post fault		
	Network Operation - FuseRestore/Bidoyng - Development of a device to automatically restore a fuse after a transient fault	IFI	£453,000			
	Network Operation - Smart Fuse	LCNF Tier 1	£350,000	Reduces impact of transient faults by autoclosing post fault		
	Network Operation/Investment Planning - Chromatic Analysis of Insulating Oil - Non-intrusive testing of Insulating Oil	IFI	£116,000	Removes the need for oil samples to be remove from transformers for analysis and allows more frequent oil monitoring		**£50k pa**
	Network Operation - Wide Area Data Gathering - Installation of a Power Line Carrier System	IFI	£95,000	Reduces the reliance on third party telecoms providers and reduces costs and increases security of communications		**£100k**
	Network Operation - Next Generation LV Board/Link Box - LV Network Automation	IFI	£579,000	Release additional capacity from distribution transformers and reduce network losses, load/generation connections at lower cost, improved power quality		**£5.5m**
	Network Operation - Customers - Research into the customer/ DNO interface and how it can be improved	IFI	£283,000	Faster more accurate information provided to customers - improved customer experience		**Qualitative**
	Network Operation - Demand control - Investigation of DNO's capability to offer technical solutions to support transmission network stability	IFI	£31,000	Allows distribution networks to be used to assist with national objectives for the adoption of renewable energy generation without customers being impacted		**Qualitative**
	Network Operation - Composite Link Box Lids - Investigation of composite materials	IFI	£11,000	Provides faster restoration times following faults		**Qualitative**

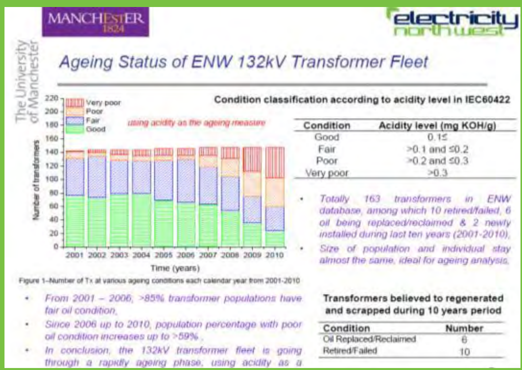
Stake-holder Priority	Innovation Initiative	Funding Type	Project Cost	Benefit	Saving Projection DPCR5	Benefit/ Saving Projection RIIO ED1
Reliability	**Investment Planning** - Oil Regeneration - Testing the capability of oil regeneration to improve health index	IFI	£270,000	Study with Manchester University into benefits of regenerating Transformer oil on site to extend their asset life		**£33m**
	Investment Planning - CBRM - Developing the ability to use CBRM outputs to define non-load investment programmes	IFI	£540,000	CBRM was initially developed for DPCR4, we have continued to develop this technique which has become the industry standard approach to asset management - improved asset decisions reliability	**>£50m**	**£65m**
	Investment Planning/Network Operation - Vegetation Management - Identification and definition of vegetation growth rates as affected by climate	IFI	£298,000	Enables targeted preparation for the affects of climate change	**-**	**Qualitative**
	Safety Network/Operation - Transient Resonance Study - Investigation into the effects of switching transformers with long cables	IFI	£70,000	Eliminates the need to provide high voltage switching devices on long cables (avoiding costs)	**£8.7m**	**-**
	Investment Planning - Network Resilience - Investigation into the potential impacts of climate change on network resilience	IFI	£24,000	Enables targeted preparation for the affects of climate change		**Qualitative**
	Safety/Investment Planning - Polymeric Investigation - Forensic Investigation of failed and new insulators	IFI	£56,000	Improves the reliability of high voltage switchgear		**Ongoing requires quantificat ion**
	Network Planning - Harmonic Cabling Modelling - Analysis of the technical requirements for the connection of non linear loads	IFI	£9,000	Allows the connection of higher levels of generation without network reinforcement	**Avoided Costs**	**Avoided Costs**
	Investment Planning - Stay Rod Testing - Non intrusive testing of below ground structures	IFI	£17,000	Testing completed and proved inconclusive and therefore will not proceed, alternative techniques will be investigated	**-**	**-**
	Network Protection and Control - Fit Calibrate HAT's - Forensic investigation of network load measurement systems	IFI	£24,000	Allows more targeted investments and facilitates connections based on available information	**-**	**Qualitative**
	Network Performance - Nafirs - Academic Investigation of fault data	IFI	£27,000	Used to develop Quality of Supply Investments and their likely effectiveness	**-**	**Qualitative**
Affordability	**Investment Planning** - Expansion Planning V2 - Development of network models for demand forecasting and pricing	IFI	£372,000	Allows more targeted investments in reinforcement for load growth	**-**	**Qualitative**
	Network Design - Earthing - Investigation of transfer potential under fault conditions	IFI	£5,400	Reduces investments in underground electrode systems	**-**	**Qualitative**
	Network Operation/Design - Fault Current Limiter - Development and installation of a super conducting fault current limiter	IFI	£540,000	Avoidance of network reinforcement to mitigate fault levels exceeding equipment safety ratings	**-**	**£3m**

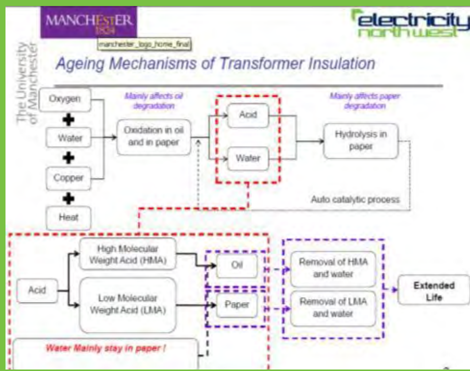
Stake-holder Priority	Innovation Initiative	Funding Type	Project Cost	Benefit	Saving Projection DPCR5	Benefit/ Saving Projection RIIO ED1
	Safety/Investment Planning - OLTC Monitoring - Acoustic monitoring of OLTCs	IFI	£277,000	Enhances safety of operatives following high profile OLTC failures and is also used to assess health of asset for more targeted investments	**£750k**	**£500k**
	Network Capacity - Dynamic Line Rating - Weather related overhead line ratings	IFI	£323,000	Allows the connection of wind turbines to remote overhead lines	**-**	**Avoided Costs**
	Network Capacity - Storage - Defining the economic and regulatory benefits of energy storage	IFI	£183,000	Facilitates the connection of low carbon technologies allowing demand management	**-**	**Qualitative**
	Network Planning - Load Related Risk - Development of load- related output measures to succeed the current Load index (LI) methodology	IFI	£20,000	Allows more targeted investments in reinforcement for load growth	**-**	**Qualitative**
Sustainability	**Demand Side Management** - DSM Signals - Assessment of DSR price signals	IFI	£15,000	Understand benefits of ENWL's Low Carbon Network Tier 2 project, C_2C-realised through avoiding investment in network reinforcement and Demand Side Response	**-**	**£10m**
	Network Capacity - Load Allocation - Development of software to project and identity overloads due to the projected take up of low carbon technologies	IFI	£460,000	Improved modelling of inherent capacity on the network as required by local conditions of increased demand and generation	**£1m**	**£600k**

A significant element of our strategy is aimed at investigating a range of issues relating to our asset management and utilisation strategy. We believe that a fuller understanding of asset condition and hence risk is a pre-requisite of a smart grid and we have developed world-leading asset management strategies through the development of condition-based risk management and condition data capture which allow greater visibility of the 'health' of our assets. These techniques, coupled with the development of criticality indices have allowed us to reduce the scope of our investment programmes whilst maintaining visibility of the increasing risk. The savings from these techniques offer substantial value for money for customers measured in tens of millions of pounds.

Case Study 1 - Oil regeneration

We have carried out research into the benefits of oil regeneration treatments for large transformers and the ability of these treatments to improve the asset health index. Manchester University carried out the investigation which included on-site regeneration of transformers under load and a definition of the life extension. This approach has allowed up to substantially reduce the number of primary transformers due for replacement during the RIIO-ED1 period.



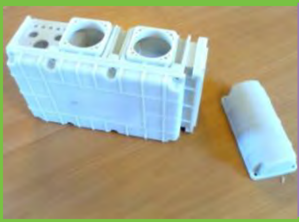


We have combined this condition information with life cycle modelling and now clearly understand how assets change condition over time and the factors that drive these changes. We have developed failure mode analysis to a high degree and have used this information to develop whole life cycle management strategies resulting in a close correlation between condition and performance both now and in the future. Our work with the University of Manchester is an example of how we have brought new transformer regeneration techniques to production readiness. This technique allows ageing grid and primary transformers to have significant life extension. The benefits of this will be realised by customers throughout RIIO-ED1 where we plan to use this technique to avoid the replacement of 12 Grid and 77 Primary transformers saving customers over £39 million.

Our work to further develop asset management techniques will continue throughout RIIO-ED1 and we plan to incorporate asset connectivity, security of supply management and more fully understand how interconnected assets in a smart grid interact to form an overall asset risk service profile.

Case study 2 – Modular Rezap

The Rezap device was initially introduced as a trial in 1997 and has since become a standard means across UK distribution networks to manage intermittent faults which may repeatedly operate fuses and disconnect customer's supplies but which cannot be easily located and repaired. The units are routinely used to switch loads on low voltage networks and are often used to switch high fault currents leading to an onerous duty on the device. One issue restricting the use of the Rezap was its size leading to it being unable to fit in a number of outdoor ground mounted substations so it was agreed to partly fund a project to resolve this issue.



Our focus in DPCR4 and 5 has been to focus on macro-performance, whereby we analysed overall trends, developed industry leading network automation software and developed leading inferencing software systems. These have allowed customers to enjoy real performance improvements in the reliability of their supply and the quality of information and support they receive during major events such as storms.

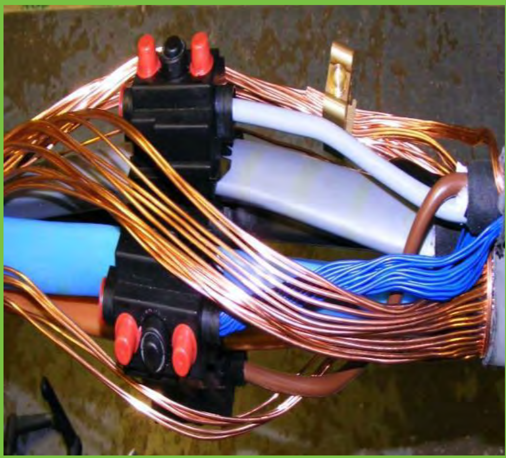
Our transmission restoration software is a particular example where we have successfully implemented the only multi voltage level self healing smart grid application. This system alone has avoided hundreds of thousands of customer interruptions.

On our LV network, we have worked with manufacturers to develop a number of devices such as the Rezap, the modular Rezap and the Bidoyng fuse restorer. These devices have transformed the management of LV network cable faults and prevent tens of thousands of customer interruptions due to transient network faults each year.

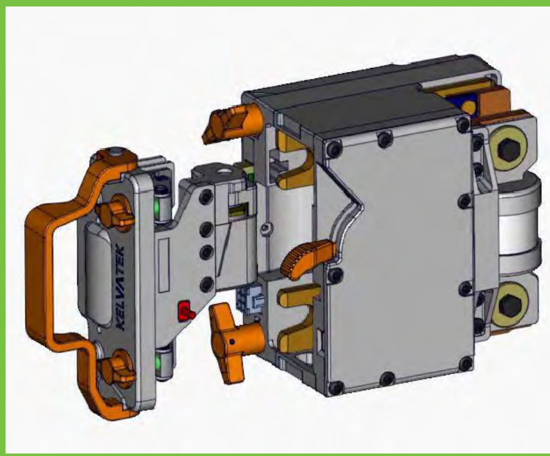
For our DG customers we have focused on allowing them to connect at the lowest possible cost. Our First Tier LCN Fund Connect and Manage project has shown that traditional network modelling techniques do not accurately predict the effect of devices such as micro-generation on network voltage. We have successfully connected over 33MW of clustered LV micro DG without any significant reinforcement.

Underpinning this connect and manage approach is the ability of the DNO to monitor the effects of DG. Prior to the advent of smart meters, we have had to develop and deploy new tools to allow us to effectively monitor DG and our smart joint is an example of innovation in this area. In addition, we have re-used Bidoyng units as advanced network sensors which coupled with the smart joints to provide a comprehensive monitoring package.

Low voltage smart joint



Smart Fuse



DG will remain one of greatest customer challenges in RIIO-ED1 and we will continue work started in our CLASS project on advanced network voltage management techniques.

We believe that the adaption of existing network assets for new services is central to any successful smart grid deployment and this approach will be core to our strategy. This asset optimisation approach allows us to respond more rapidly to issues such as the clustered adoption of new technologies whilst keeping costs to customers to a minimum.

As smart meters are deployed, these will be integrated into our control room systems allowing better management of network power flows and further improved fault diagnostic techniques. The realisation of smart meter benefits will require cleansing of existing data and these costs are detailed in our business plan.

In addition to our leadership of Workstream 3 and the development of our future capacity headroom model[7], we have invested significant time and resource in understanding and forecasting the impact of low carbon technologies on networks.

Our stakeholder engagement clearly shows that in order for customers to adopt these new technologies the connection experience must be streamlined and simple. We have already noted our leadership of the ENA work groups in this area. We will continue to work with stakeholders to develop new technical and commercial solutions such as C_2C and other flexible connection arrangements.

We have achieved a leading position on commercial innovation and commissioned a report by Pöyry Management Consulting to investigate the potential strength of price signals under various scenarios to drive customer behaviour.

The commercial models used to deliver services to our customers are becoming ever more important and we have recognised the opportunity to enhance the economic opportunity for new connections. Our C_2C project is a clear example of how connections can be facilitated at significantly reduced cost by adopting new commercial arrangements that exploit latent network capacity. Such arrangements are ideal for customers such as landfill DG sites which

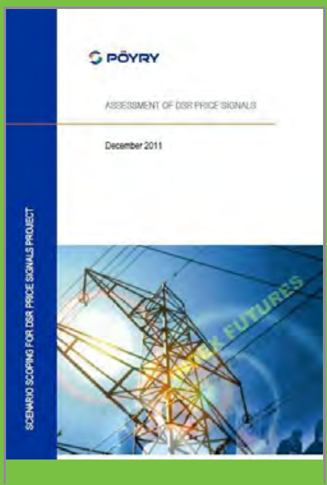
[7] This model provides a top to bottom model of the entire Electricity North West network and enables LCT penetration scenarios to be over laid onto various economic activity levels to produce an assessment of future network utilisation and hence reinforcement / Smart Grid technology intervention requirements.

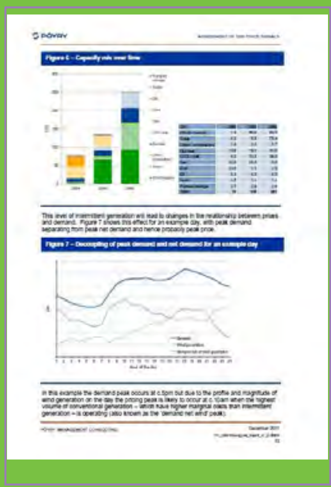
can store and use methane gas to generate electricity. These sites often only have enough gas to generate for 10 or 15 years therefore our new flexible connections are an ideal way of avoiding expensive reinforcement charges to build assets that may last for 40 years or more.

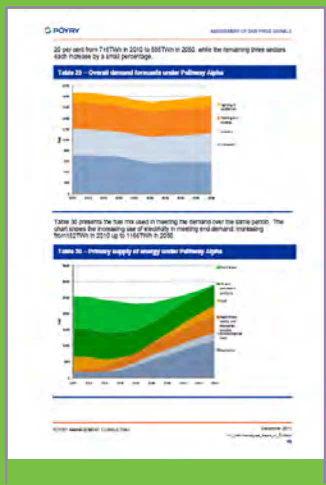
Case Study 3 - DSR

Pöyry Management Consulting was jointly commissioned by Electricity North West and National Grid to explore further the interactions of potential DSR use by Electricity North West (as a DNO), National Grid (as TSO) and suppliers as different key end users and to examine relative strengths of DSR price signals that each might be able to provide to the market.

The expectation is that a decarbonised generation sector will lead to the GB market containing large amounts of low marginal cost generation; much of this will be in the form of wind, which is also intermittent. Concurrent with the decarbonisation of electricity generation, further electrification of the heat and transport sectors is expected, particularly from the late 2020s onwards, in support of the 2050 emissions target.







We have invested time and effort in understanding the value to customers in our present service offerings and what will be required in the future.

We will bring new innovative commercial services to the market that reflects the requirements of connectees rather than the asset-centric view of our network that has dominated for many years.

The provision of consistent low cost and flexible connection offers will require further innovation work in areas such as harmonic filtering and storage to allow the benefits of these new technologies to be passed on to customers.

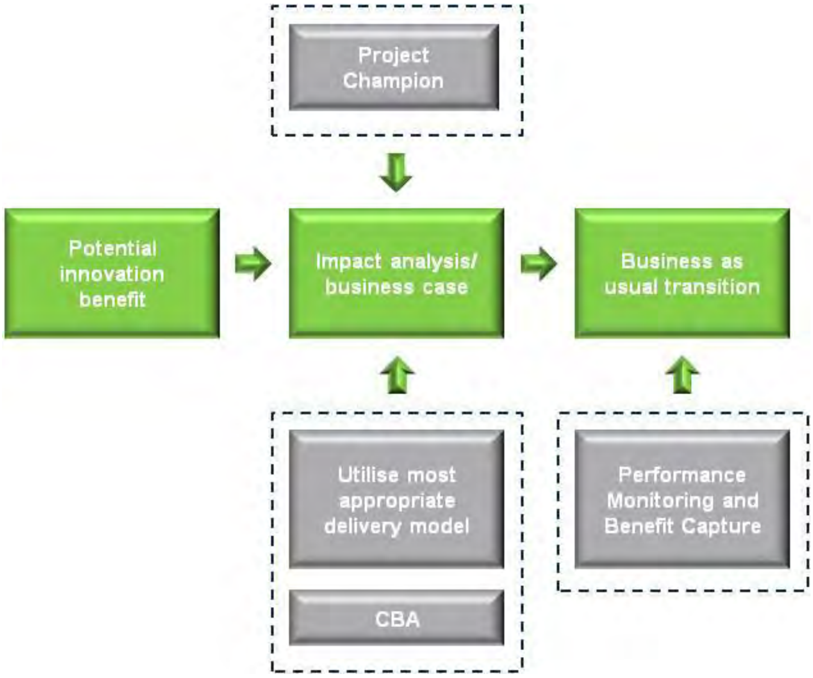
Our work in the CLASS project recently funded by Ofgem under the Second Tier LCN Fund funding competition will, in addition to reinforcement deferral, allow us to develop added value services for customers from techniques such as automated frequency response. The techniques that will be proven by CLASS will allow savings of hundreds of millions of pounds for UK customers in the future.

7. Rolling out successful innovation as business as usual

The critical step in delivering benefits to customers from innovating is managing the transition of a solution, device, technology or other innovation into business as usual. The governance framework, described earlier in the Innovation strategy section, showed our high level approach to taking a project output from an Electricity North West managed project or from an external source (whether domestic or international).

We track others' innovation activities alongside the delivery of our innovation projects. As projects move through their lifecycle and it becomes clear that the outputs have the potential to be embedded as business as usual a Project Champion is identified for each project. The Project Champion has the responsibility for evaluating the innovation and deciding whether the innovation should be transition into business as usual. Figure 10 overleaf shows the Project Champion has the responsibility to complete the business case for the innovation and evaluate the change required to implement the innovation in the business. At this stage the aligned with RIIO-ED1 programme will be confirmed and a go (or delayed go) or no-go will be determined.

Figure 10: Innovation strategy linked to challenges and stakeholder priorities



These activities will be completed with the support of the Future Networks team and will follow, where appropriate, the normal project management approval and delivery processes to ensure consistency.

Where there is a multi-directorate impact the Future Networks team will assist in the co-ordination of multi-directorate changes with the Project Champion leading and agreeing the implementation with the business managers. For example the introduction of a new piece of equipment will require some level of policy changes that could impact on a procurement process (ie development of a standard/ specification for supply change development) and/ or an operational process (ie development of a Code of Practice for the operation and maintenance arrangements) both which may require briefing and/ or training.

On implementation the Project Champion has the responsibility to monitor and confirm the identified benefits have been obtained.

8. Our innovation plan

8.1 Delivering innovation in RIIO-ED1 2015–2023

Our DPCR5 innovation strategy is focussed on discrete projects aligned with our key stakeholder priorities of reliability, affordability sustainability and customer service. Moving forward the RIIO-ED1 plan will shift focus to combine these areas, recognising that future smart grid needs will increasingly require a co-ordinated approach to the forecasted challenges and to meet broader stakeholder priorities.

Our RIIO-ED1 initiatives will require extensive third party collaboration for delivery. Almost 80% of our current IFI funding goes to third parties (such as universities and UK businesses) and makes a significant contribution to the regional Research and Development investment. We anticipate a similar apportionment of funds through RIIO-ED1.

Table 5 overleaf shows across the RIIO-ED1 timeline the range of innovation initiatives planned grouped within the stakeholder priorities. Further information on each of the initiatives is contained within Annex 1.

8.2 RIIO-ED1 2015-2019

Through 2015-2019 we will focus upon completing the network capability initiatives currently in development in DPCR5 (LV network automation and storage for example) and in the capture and use of the extensive amount of load and usage data that will be provided by smart meters to further enable the development of smart grids.

During this period we expect increasing customer demand and the clustered connection of low carbon technologies to push local network capacity to its limits. We will focus on understanding in greater detail the capability of our network to expand and meet demand increases whilst maintaining exceptional levels of reliability and customer service.

We will use innovative approaches to provide a smarter response from our current network:

- Focus on the collection of real-time data on network performance, capacity and load from automated data capture, including data from smart meters;
- Use advanced system simulation and modelling techniques such our Capacity Headroom Model to identify and quantify network capacity and identify areas of strain on our network in real time;
- Integration of smart meters into control room systems;
- Progress development of technologies currently in research through continued collaboration with our partners to achieve our stakeholder priorities;
- Develop and invest in our employees' core skills in the areas of commercial, financial and technical innovation;
- Focus on the delivery of priority services for vulnerable customers and those affected by fuel poverty;
- Continue our leadership in industry forums and working groups.

Testing the network smart grid capability is one discrete step in the on-going process of migrating to a more active network approach and a demand side response. We will also consider our post-2019 activity and how experience from this early stage affects the development timescale.

8.3 RIIO-ED1 2019–2023

Our focus in this period will be the delivery of our data strategy and use of smart meter information to drive further efficiency, reliability and low carbon capacity on our network:

- Micro level data management of network performance;
- Move from research and development to industrialisation of developed technologies;
- Response to stronger market demand within RIIO-ED1 for DSR and an increased requirement to manage network constraints and balance network supply;
- Development of RIIO-ED2 investment plans based on real time data and Demand Side Response outputs;
- Roll-out of solutions supporting the increased level of heat and transport load on our network.

Once we have developed the smart grid techniques to 'drive' the network in this way it will be possible to fully define the financial benefits in measurable terms for our stakeholders.

Real time operations will necessitate a revision in our approach to data management and communications; data will become a key asset and we will use it to inform our overall network operations, asset management and service performance across all elements of our business. We will use data to drive innovation.

- Completion of our innovation delivery plan and the realisation of the potential from these systems will underpin our RIIO-ED2 investment plans. The ED2 period is forecast to see a dramatic increase in the rate of heat and transport load on electricity networks and industrialisation of the developed technologies. Readiness for this uptake will be a key priority between 2019 and 2023.

Table 5: Timeline for RIIO-ED1 Innovation Initiatives 2015-2023

Stakeholder Priority	Innovation Project Initiative	Year\ Voltage	2015	2016	2017	2018	2019	2020	2021	2022	Projected Project Expenditure (£m)
Reliability/ Sustainability	Load Impact Modelling	LV									**£0.82**
		HV									
Reliability/ Affordability	Thermal Capability	LV									**£1.2**
		HV									
Reliability/ Affordability	Asset Management	LV									**£1.2**
		HV									
Reliability Customer service	Automatic Fault Restoration	LV									**£1.5**
		HV									
Reliability/ Sustainability	Development of Autonomy	LV									**£0.82**
		HV									
Affordability/ Sustainability	Network Configuration	LV									**£1.2**
		HV									
Affordability	Reference Networks	LV									**£1.2**
		HV									
Affordability	Network Modelling	LV									**£1.65**
		HV									
Affordability/ Customer service	Feeder Operational Modes	LV									**£1.2**
		HV									
Sustainability	Voltage Management	LV									**£2**
		HV									
Sustainability	Feeder Design	LV									**£1.5**
		HV									
Sustainability	New Materials	LV									**£1.2**
		HV									

Stakeholder Priority	Innovation Project Initiative	Year\ Voltage	2015	2016	2017	2018	2019	2020	2021	2022	Projected Project Expenditure (£m)
Sustainability	Data Clouds	LV									**£1.2**
		HV									
Customer service	Demand Side Response	LV									**£2**
		HV									
Customer service / Affordability	New Connections	LV									**£1.2**
		HV									
Customer Service	DSO Services	LV									**£2.92**
		HV									
Customer service	High Performance Computing/ Data Manipulation	LV									**£0.82**
		HV									
										Total	**£23.63M**

8.4 Innovation initiatives aligned to RIIO-ED1 framework

Each of the initiatives have been developed to ensure the expected outcomes deliver benefits in the areas identified by our stakeholders ie their key priorities; and the whole innovation programme has been reviewed to ensure the initiatives collectively fulfil in both breadth and depth the Ofgem outputs expected from the RIIO-ED1 framework. Table 6 below shows the cross-referencing of the each initiative to the Ofgem outputs and our stakeholder priorities confirming our proposed RIIO-ED1 innovation programme aligns with our stakeholders' priorities and Ofgem six outputs. As described earlier in the innovation governance section we will manage and monitor the delivery of each innovation project and the delivery of the whole innovation programme as this is key to the realisation of our stakeholders' requirements and the expected Ofgem outputs.

Table 6: Innovation initiatives linked to Ofgem outputs challenges and stakeholder priorities

Innovation Project Initiative	Ofgem Outputs						Stakeholders' Priorities
	Reliability and availability	Safety	Social obligations	Environmental Impact	Customer Satisfaction	Connections	
Load Impact Modelling	●			●	●	●	Reliability/ Sustainability
Thermal Capability	●	●		●	●	●	Reliability/ Affordability
Asset Management	●	●	●	●	●	●	Reliability/ Affordability
Automatic Fault Restoration	●				●		Reliability/ Customer service
Development of Autonomy	●	●	●	●	●	●	Reliability/ Sustainability
Network Configuration	●	●	●		●	●	Affordability/ Sustainability
Reference Networks	●			●		●	Affordability
Network Modelling	●		●	●			Affordability
Feeder Operational Modes	●		●	●	●		Affordability/ Customer service
Voltage Management	●	●		●	●	●	Sustainability
Feeder Design	●	●	●	●	●	●	Sustainability
New Materials	●	●	●	●	●	●	Sustainability
Data Clouds	●			●	●		Sustainability
Demand Side Response	●		●	●	●	●	Customer service
New Connections	●		●	●	●	●	Customer service / Affordability
DSO Services	●		●	●	●	●	Customer Service
High Performance Computing/ Data Manipulation	●	●	●	●	●	●	Customer service

8.5 The consequences of not innovating

Innovation is an essential part of our RIIO-ED1 business plan and preparation for the expected increased uptake of Low Carbon Technologies in the latter part of RIIO-ED1 and into ED2. Not innovating will have a detrimental impact on our ability to deliver against our stakeholders' key priorities of affordability, reliability, sustainability and customer service. Not innovating would have the direct consequence of:

- Losing the opportunity to maximise the use of existing assets and reducing the cost of operating networks;
- Inability to develop and test alternative techniques instead of relying on traditional reinforcement solutions;
- Hindering the low carbon transition due to the lack of understanding of the impact of low carbon technologies and the portfolio of solution options;
- Hinder our ability to engage with customers in the operation of the network and offer a range of alternative connection and operational arrangements; and
- Hinder our ability to think through and test the roadmap from a distribution network operator to a distribution system operator.

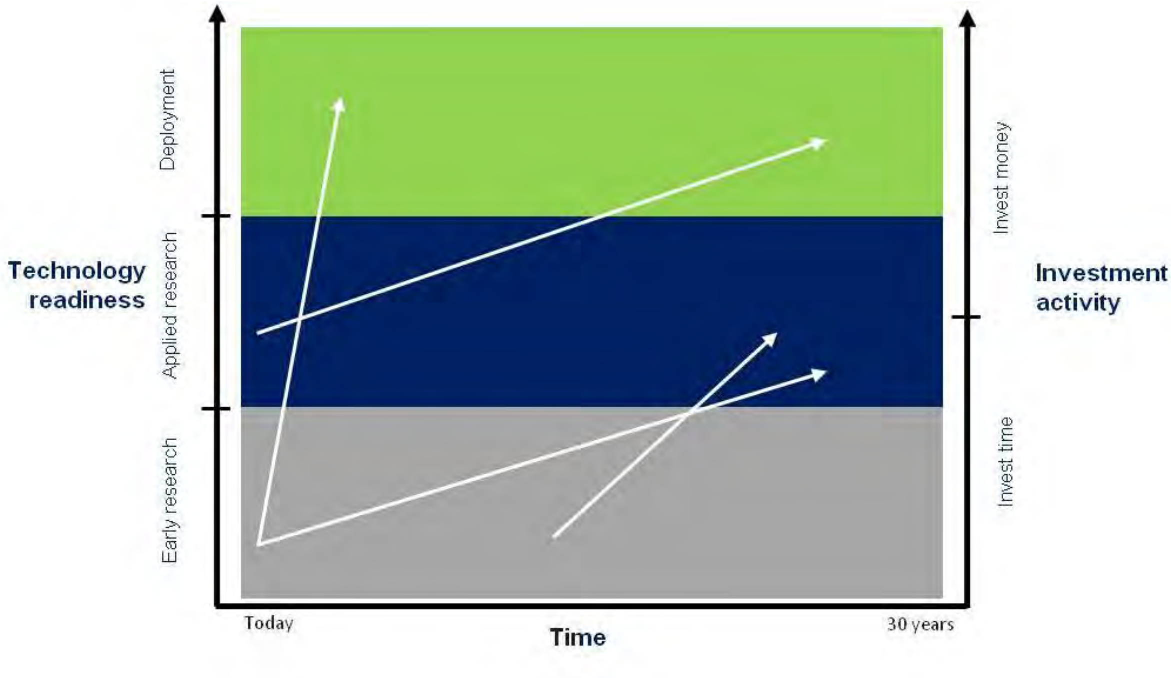
Further information on the consequence of not undertaking each of the innovation initiatives targeted for RIIO-ED1 is contained within Annex 1.

8.6 Ongoing strategy development

Our innovation strategy will evolve through 2015 to 2023. Each year we will review our strategy and the associated innovation programme and every other year we will seek input from our stakeholders on our approach and direction. The development of a deliverable smart grid strategy, contained in annex 13, for RIIO-ED1 requires rules to guide our innovation investment decisions. Our strategy needs to take into account new and emerging technologies that might today appear to be far from being commercially available but may have a significant effect if they did reach a high technology readiness level.

We need to ensure we have a proactive role in relevant product/ technical developments and keep all elements of these developments under surveillance. To enable this approach we have defined a technology development life cycle that is relevant to our businesses future needs. Figure 11 below illustrates our lifecycle approach to guide when we should support and when we should invest.

Figure 11: The challenge of predicting relevant technology development



For example our early stage support (of the technology development cycle) could be with technical specifications or target price points and in later stages support could be with appropriate financial investments. We see many new technologies that could be relevant to DNOs including carbon fibre cables, power electronic transformers and circuit breakers and nano-materials. The challenge is to look into the future and direct our limited resources at those developments to ensure the right pace of new technology development and adoption. We have developed clear rules that help us to rationalise decisions and define which areas offer the greatest benefits for our stakeholders. Our overarching objective is efficient delivery and use of our own network capacity. We also need to be clear where we expect the market to deliver innovations, but concurrently ensure we are fully aware of where new markets and opportunities arise for example retail market developments from greater customer engagement.

9. Glossary

BEAMA	British Electrotechnical and Allied Manufacturers' Association
CAPEX	Capital Expenditure
C_2C	Capacity to Customers – an LCN funded project
CBRM	Condition Based Reliability Maintenance
CHP	Combined Heat and Power
CLASS	Customer Load Active System Services – an LCN funded project
DECC	Department of Energy & Climate Change of UK Government
DG	Distributed Generation
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review period ie DCPR5 is 2010 to 2015
DSO	Distributed System Operator
DSR	Demand Side Response
EIC	Energy Innovation Centre
ENA	Energy Networks Association
EHV	Extra High Voltage, voltages greater than 11kV, up to and including 132kV
EV	Electric vehicle
ETR	Engineering Technical Report
FFC	Fluid Filled Cables
GB	Great Britain
HV	High Voltage, voltages greater than 1000V up to and including 11kV
IET	Institution of Engineering and Technology
IFI	Innovation Funding Incentive
IRM	Innovation Roll-out Mechanism
KPI	Key Performance Indicator
LCN Fund	Low Carbon Network Fund
LCT	Low Carbon Technologies
LRE	Load Related Expenditure
LV	Low Voltage, voltages up to and including 1000V
MP	Member of Parliament
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NLRE	Non-Load Related Expenditure
OPEX	Operational Expenditure
PV	PhotoVoltaic
QoS	Quality of Supply
RIIO-ED1	Revenue = Incentives + Innovation + Outputs (RIIO) – first electricity distribution price control (ED1)
RIIO-ED2	Second electricity distribution price control (ED2) under RIIO framework
RTU	Remote Terminal Unit
RTTR	Real Time Thermal Rating
TSO	Transmission System Operator
UK	United Kingdom
UKPN	UK Power Networks

10. Annex 1: RIIO-ED1 Innovation Initiatives

Load Impact Modelling

Area	Reliability/ Sustainability	**Objective**	• Develop load models • Investment planning • Capacity thresholds
Expected outcome		Improved design standards and investment decision	
Consequence of not undertaking		Reduced ability to prepare effectively for connection of new LCTs	

Background

The adoption at scale of low carbon technologies is forecast to increase the demand for electricity over the RIIO period. The effects of these demand increases in on distribution network capacity and investment planning need to be appropriately understood in order to optimise interventions and thus avoid potentially expensive reinforcement. Energy usage and peak load forecasting over the RIIO period is extremely complex with high levels of uncertainty owing to the unknown and at times random patterns of adoption of these new technologies. Appropriate visibility of the ongoing relationship between demand growth and associated network investment is a key issue underpinning network investment needs over the RIIO period.

Proposal

The objective of this project is to develop and deploy a suite of planning tools which aim to replace empirical techniques and which can be used to model the effects on the distribution networks with increases in electrical loads. It is proposed to construct a total system peak loading model to evaluate and quantify the relationship between demands and investment and allow us to better quantify the volume and value of network side response available.

Benefits

This project will bring benefits to customers in the form of improved distribution network capacity and investment planning. It will enable us to better model the relationship between the adoption of low carbon technology and the requirements for network investments.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional Specification	Internal	24	£0.82m
Development of network models	Academic/Tech Provider		
Produce demand forecast scenarios	Internal/Academic		
Technical Specification	Tech provider		
Design and build tools	Tech provider		
Test	Tech provider		
Deploy	Tech provider		
Analysis	Internal		

Thermal Capability

Area	Reliability/ Affordability	**Objective**	• Develop enhanced ratings • Investment planning • Capacity thresholds
Expected outcome		Improved system utilisation and updated operating standards	
Consequence of not undertaking		Opportunity lost to maximise utilisation of existing assets; likely requirement for additional network investments	

Background

A significant amount of work has been undertaken to establish the true ratings of electricity distribution network assets as opposed to standard nameplate ratings designated by original equipment manufacturers. This work has begun to establish the true link between loadings, ambient temperature and asset degradation or aging but to date it has been in the main limited to examining individual asset groups, particularly large and expensive transformers that can be monitored and examined with relative ease.

Proposal

It is proposed to take a more holistic approach to network thermal capability with the aim of enabling higher circuit ratings for the connection of low carbon generation and loads. The project will build on the work carried out to date but will examine and develop models for entire circuits and all components within those circuits. It will further develop the link between loads and asset degradation with the aim of moving away from traditional 'seasonal' circuit ratings. Initial work has shown that transformers for example can accept considerably higher loads (particularly in winter) with no negative effects and it is thought that this approach could be extended to entire circuit provided the necessary understanding could be developed. The approach could be used to enhance ratings at particular time of the year or to provide higher short term ratings under outage conditions.

Benefits

The benefits from this project will arise from being able to run networks to their actual limits (within thermal and ageing parameters) so releasing further network capacity across all voltage levels.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Establish priorities for circuit elements	Internal	36	£1.2m
Review work to date	Academic/Tech Provider		
Enhance available models	Internal/Academic		
Develop enhanced monitoring based on sensitivity analysis	Tech provider		
Install monitoring on selected circuits	Tech provider		
Develop IT hardware and links to Network Management System	Tech provider		
Measure increased capacity	Tech provider		

Asset Management

Area	Reliability/ Affordability	Objective	• Investment planning • Capacity thresholds • Asset life extension
Expected outcome		Improved condition based assessment and operating practises	
Consequence of not undertaking		Lost opportunity to maximise life of existing assets; likely requirement for additional network investments	

Background

Electricity distribution network asset management techniques have changed radically since privatisation, moving from time-based interventions according to manufacturers' instructions to data capture and condition-based management techniques. This change has led to significant improvements in asset reliability and life extension and enhanced efficiency and the techniques developed by this industry have been adopted by other utility industries both domestic and overseas.

Proposal

It is proposed to continue to enhance our approach to asset management to reflect the ageing nature of our network and the evolution of network running arrangements where networks will experience higher loadings. The investigation will include all aspects of asset management and broadly cover issues such as:

- An enhanced understanding of how different assets change condition (from healthy to requiring maintenance or intervention) and the factors that drive these changes;
- Further development of methods to design optimum intervention strategies;
- Development of a better understanding of materials and data analysis and data gathering; and
- Extending non-intrusive testing techniques.

Benefits

By common agreement the development of condition-based asset management techniques has resulted in significant financial benefits to our industry. The results of this project will allow us to employ the latest techniques and data analysis algorithms to ensure that we can meet the challenge resulting from long term changes to the role of distribution networks in supporting the migration to a low carbon economy.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Review of previous work and development of specific aims and objectives	Internal	36	£1.2m
Development of asset classes	Internal		
Development of enhanced data management and manipulation	Tech provider		
Sensitivity analysis of condition data capture	Academic		
Forward modelling and scenario analysis	Tech provider/ Academic		
Integration into BAU	Tech provider/Internal		

Automatic Fault Restoration

Area	Reliability/ Customer service	**Objective**	• Network automation • Improved QoS • Improved reliability • Improved availability
Expected Outcome		Enhanced fault restoration capabilities	
Consequence of not undertaking		Lost opportunity to improve system reliability; reduced customer satisfaction	

Background

Technical developments in the form of improved telecommunications, more advanced remote terminal units with enhanced battery performance together with advances in network control room management functionality has allowed operators to automate the restoration of supplies in the event of a faults. These techniques have been successfully applied to higher voltage networks significantly enhancing the quality of supply. In recent years, this technology has now begun to be deployed on lower voltage networks thus facilitating the potential adoption of automation on these networks.

Proposal

The project will look to trial the deployment of automated fault restoration on the low voltage networks. It will build upon the principles developed as part of higher voltage deployments and seek to leverage the integration of new smart grid technology on the low voltage network including automated low voltage substations and link boxes. The project will develop a number of alternative restoration algorithms.

Benefits

The project will benefit customers by significant enhancing the reliability of the low voltage networks and reducing the duration of low voltage interruptions. This is considered to be a particularly key development as customers become increasingly reliant on safe and reliability electricity as they adopt low carbon technology to heat their homes and power their cars.

Tasks

Tasks	**Resource**	**Duration (months)**	**Indicative Costs**
Functional specification	Internal	48	£1.5m
Development of network models	Academic/Tech Provider		
Select trial networks	Internal		
Technology selection	Internal		
Technical specification	Tech provider		
Procurement	Internal		
Design and build (Software)	Tech provider		
Test	Tech provider		
Deploy	Tech provider		
Analysis	Internal/Academic		

Development of Autonomy

Area	Reliability/ Sustainability	**Objective**	• Develop load models • Investment planning • Capacity thresholds
Expected Outcome		Optimised use of network assets	
Consequence of not undertaking		Reduced capability of network to host low carbon loads	

Background

In the most general sense Autonomy can be defined as the ability of a person or entity to make informed decisions. The concept is widely used in many physical sub-systems where sets of rules are developed and systems are enabled to follow and act on these rules without resorting to third parties for guidance or checks. Autonomy is already used at higher voltages to restore supplies to customers following faults on EHV networks through automatic restoration systems where 'healthy' parts of the network are automatically switched back in without any input from network control engineers.

Proposal

As automation is extended across the network to lower voltage levels through the development of low voltage circuit breakers and as thermal and enhanced ratings are developed it will be necessary to make an increasing number of decisions regarding network configurations to release the additional capacity required. The aim of this project is to recognise that it will become impractical to increasingly require control engineer intervention to manage networks and a greater level of network 'self-awareness' will be required. This could include automatic meshing of low voltage networks to manage loads based on thermal ratings of distribution transformers. The project will examine data links and command and control algorithms and will merge network protection and control functions into a single entity with the aim of removing the requirement for human intervention.

Benefits

It must be recognised that the scale of switching and network control decisions may increase exponentially in response to the deployment of new switching devices and the need for additional network capacity. The benefits of this project will result from a better ability to run the electricity network to its limits across ever greater areas and voltage levels and it will also eliminate the potential for errors.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Project scoping	Internal	36	£0.82m
Requirements definition	Academic/ Internal		
Sensing and data transmission	Tech provider		
Autonomy algorithm development	Internal/Academic		
Implementation	Tech provider		
Testing	Internal/Tech provider		
Deployment	Internal/Tech provider		

Network Configuration

Area	Affordability/ Sustainability	**Objective**	• Network design • Network operating standards • Commercial contracts
Expected outcome		Updated operating practises	
Consequence of not undertaking		Opportunity to maximise use of existing assets	

Background

Historically in the UK electricity networks have been designed to delivery electricity generated at scale in large out of town power plants to customers in load centres via interconnected transmission systems and radial distribution networks. The flow of energy was unidirectional from the point of generation to the load centres and the role of the customer was as consumer. However, the increases in embedded generation, the adoption at scale of low carbon technologies and the role of the customer as an active participant in energy markets is changing the characteristics of distribution networks resulting in increasingly dynamic, bi-directional power flows.

Proposal

The objective of this project is to develop and trial alternative distribution network configurations which aim to best address the emerging challenges of low carbon loads and the changing requirements of customers.

Benefits

This project will bring benefits to customers in the form of improved distribution network designs and configurations which facilitate the low cost adoption at scale of low carbon technologies.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Design	Internal	36	£1.2m
Develop commercial contracts	Academic/Tech Provider		
Specify and develop new technology	Internal/Tech Provider		
Procurement	Consultants		
Construction	Internal		
Analysis	Internal/Academic		

Reference Networks

Area	Affordability	**Objective**	• Reference networks • Modelling • Planning and design
Expected outcome		Improved network design and operating standards	
Consequence of not undertaking		Impaired ability to effectively manage networks with LCTs connected	

Background

The adoption at scale of embedded generation on HV and LV networks will increase the difficulty associated with obtaining appropriate voltage regulation across these networks throughout the seasonal load cycles. The addition of large electrical heating loads and vehicle charging will add to this challenge. Issues associated with phase voltage imbalance and harmonics are also of concern to operators.

Proposal

The objective of this project is to develop a small number of reference networks to support ongoing planning and design of future networks based upon common network and demand characteristics. The reference networks will be used to characterise the effects of the adoption of low carbon technologies and to support the development of a suite of mitigation measures to best address the emerging challenges of low carbon economies and the changing demands of customers. As both design and operation have a direct effect on end customers, there is a case for appropriate simulation and testing of new designs and changed operating practices before using such new approaches for real. Testing, modelling and simulation will allow approaches to be both de-risked in terms of customer effects and optimised in terms of customer benefits. Some modelling, such as the power system behaviour of individual new power system components is business as usual and for which well established test approaches exist. But many aspects of considerations beyond single components of the power system do not have well established assessment approaches, and a degree of development is required in many cases.

Benefits

This project will bring benefits to customers in the form of improved distribution network planning and design thus reducing overall costs and facilitating the transition to low carbon networks. Failure to be able to easily assess and test new design and operating approaches could reduce the benefits of possible network efficiencies available to customers, and in some cases expose them to new risks.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional specification	Internal	36	£1.2m
Technical specification	Academic/Tech Provider		
Design and build (Software)	Internal/Tech Provider		
Test	Consultants		
Deploy	Internal		
Analysis	Internal/Academic		

Network Modelling

Area	Affordability	Objective	• Operation and control • Modelling • Planning and design
Expected Outcome		Enhanced modelling tools	
Consequence of not undertaking		Inability to appropriately model the effects of the connection of LCTs	

Background

Historically in the UK electricity networks have been designed to deliver electricity generated at scale in large out of town power plants to customers in load centres via interconnected transmission systems and radial distribution networks. The flow of energy was unidirectional from the point of generation to the load centres and the role of the customer was as a consumer. However, the increases in embedded generation, the adoption at scale of low carbon technologies and the role of the customer as an active participant in energy markets is changing the characteristics of distribution networks resulting in increasingly dynamic, bi-directional power flows.

Proposal

The objective of this project is to develop network modelling tools which will provide the capability to assess the effects of the adoption of low carbon technology, support the analysis of the impacts of alternative network configurations, and provide optimisation of network investment versus commercial arrangements. Network models to be applicable in both operational and planning timescales.

Benefits

This project will bring benefits to customers in the form of improved distribution network models which will provide improved capability to assess the effect of emerging customer demand requirements and understand the need for associated network reinforcement.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional specification	Internal	36	£1.65m
Development of network models	Academic/Tech Provider		
Data collection, cleanse and load	Internal/Academic		
Technical specification	Tech provider		
Design and build (Software)	Tech provider		
Test	Tech provider		
Deploy	Tech provider		
Analysis	Internal/Academic		

Feeder Operational Model

Area	Affordability/ Customer service	**Objective**	• Operation and control • Configuration • Standards and design
Expected Outcome		Alternative network operating configurations	
Consequence of not undertaking		Lost opportunity to maximise use of existing assets	

Background

Increases in embedded generation, the adoption at scale of low carbon technologies and the role of the customer as an active participant in energy markets is driving change in the characteristics of distribution networks resulting in increasingly dynamic, bidirectional power flows. Traditionally low voltage feeders are designed and operated on a taper and forget configuration where the feeder is largely static with its configuration only being altered for maintenance activities or when customers complain of power quality. All feeders are protected by fuses and many are fitted with link boxes. Fuses and links can be replaced by retrofit smart devices such as switch fuses offering the capability to mesh networks or reconfigure in real time.

Proposal

The objective of this project is to develop alternative network operating modes which are better suited to the future demand characteristics of low carbon technologies and embedded generation. The project will consider the costs and benefits of the various options supported by field trials and simulation.

Benefits

This project will bring benefits to customers in the form of optimum power and energy transfer across the load cycle thus facilitating the connection of low carbon technology at lower cost. The alternative operational modes will result in improved power quality and reduced harmonic distortion.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional specification	Internal	36	£1.2m
Development of network models	Academic/Tech Provider		
Select trial networks	Internal		
Technology selection/ spec	Internal		
Procurement	Internal		
Design and build (Software)	Tech provider		
Test	Tech provider		
Deploy	Tech provider		
Analysis	Internal		

Voltage Management

Area	Sustainability	**Objective**	• Voltage regulation • Losses • Harmonics/Unbalance
Expected Outcome		New network voltage operating solution and standards	
Consequence of not undertaking		Lost opportunity to maximise use of existing assets and meet the emerging requirement of customers	

Background

The adoption at scale of embedded generation on the HV and LV networks will increase the difficulty associated with obtaining appropriate voltage regulation across these networks throughout the seasonal load cycles. The addition of large electrical heating loads and vehicle charging will add to this challenge. Issues associated with phase voltage imbalance and harmonics are also of concern to operators.

Traditional LV feeder design is based on a voltage standard as outlined in BS EN50160 which assumes stochastic loads and a demand of 1.5kW per customer. This gives a nominal feeder voltage drop of 7% at maximum demand with a slightly higher than nominal sending voltage. Studies indicate that existing networks can accept micro-generation penetration levels of up between 25% and 50% but that beyond these levels voltage standards cannot be guaranteed.

Proposal

The objective of this project is to develop new innovative techniques for achieving distribution network voltage management which are aim to best address the emerging challenges of low carbon economies and the changing demands of customers.

Benefits

This project will bring benefits to customers in the form of improved distribution network voltages and network efficiency which will have the effect of facilitating the low cost adoption at scale of low carbon technologies and the transition to a low carbon economy.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional specification	Internal	48	£2m
Development of network models	Academic/Tech Provider		
Select trial networks	Internal		
Technology selection	Internal		
Technical specification	Tech provider		
Procurement	Internal		
Design and build (Software)	Tech provider		
Test	Tech provider		
Deploy	Tech provider		
Analysis	Internal/Academic		

Feeder Design

Area	Sustainability	Objective	• Design • Planning • Reinforcement
Expected Outcome		New network design standards	
Consequence of not undertaking		Lost opportunity to maximise use of existing assets	

Background

The current design of the LV network effectively places the HV transformation point up to 1000m from the feeder end customer. This design drives a higher installed LV to HV network ratio than used in other designs such as in the USA. Installing a higher number of smaller transformers closer to the end customer has a number of technical advantages such as improved voltage regulation and power quality but at a potentially higher overall cost. A longer term objective is therefore to revisit this connection design with a view to optimising performance and costs on a smart grid.

Proposal

The project will consider alternative LV feeder designs which are better suited to accommodating higher penetration of low carbon technology. The project will consider a range of options including both tactical network addition and the designs to be deployed on totally new installations. The project will consider the cost and benefits of the alternative options.

Benefits

The project will benefit customers by ensuring that the low voltage networks can readily accommodate the connection at scale of low carbon technology such as PV, EV charging and electric heat pumps without the requirement for significant cable overlays.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Design	Internal	36	£1.5m
Develop designs	Academic/Tech Provider		
Procurement	Consultants		
Construction	Internal		
Analysis	Internal/Academics		

New Materials

Area	Sustainability	**Objective**	• Develop load models • Investment planning • Capacity thresholds
Expected Outcome		Knowledge of alternative materials for use in power systems	
Consequence of not undertaking		Hinder the ability to make decisions on the use of alternative materials in power systems	

Background

Generally assets installed on electricity networks originally consisted of copper conductors and steel tanks and containers and in the main cellulose and mineral oil-based insulation media. Recent decades have seen the introduction of polymeric-based insulation and gasses such as sulphur hexafluoride but mounting environmental awareness and raw material costs has served to increase the need to find more acceptable; alternatives, in terms of cost, reliability and environmental impact.

Proposal

Research has demonstrated that a range of new materials are under development that could offer considerable benefits to the design of electricity network assets. These include nano-engineered materials, Graphene, carbon nanotubes and room temperature superconductors. This project intends to examine the availability and applicability of these materials but it should be clearly stated that the project will not fund material development; rather it is aimed at working closely with materials scientists and developers both in industry and academia to ensure we influence appropriate developments.

Benefits

The benefits of this project will be in the long term and are hard to define. The rate of material developments is such that towards the end of the RIIO ED1 period in 2023 there is a remote possibility that literally revolutionary new materials may be available for commercial use. Any developments of these materials will not be funded by us but support for a broad range of near and longer term innovations must be a part of any balanced innovation strategy.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Research	Internal	36	£1.2m
Engagement with relevant experts	Academic/Tech Provider		
Financial modelling of potential benefits	Tech provider		
Trials	Tech provider		
Evaluation	Tech provider		

Data Clouds

Area	Sustainability	**Objective**	• Data management • Operations • Planning
Expected Outcome		Data storage and management specification	
Consequence of not undertaking		Hinder the storage and manipulation of smart metering data	

Background

The development of smart grids and the increased use of automated technologies on HV and LV networks have resulted in significant increases in the deployment of network sensors and monitors; a trend that will continue throughout the RIIO period. This together with the expected arrival of smart meters will result in extremely high volumes of loading and other analogue data which will be available to network operators to support future network operations. The management of these new high volume data sets presents a significant challenge to network operators who are likely to need this data (often in near real-time) to support network operation and planning.

Proposal

This project will investigate options available to the network operator for the capture, storage and extraction of network data. The project will consider the full range of data sets that will become available as outlined above and how best this data can be captured and stored. Storage options are likely to include consideration of cloud solutions as well as traditional physical media. The need to extract meaningful information from these large data sets is clear and the project will consider the business requirements and the most appropriate analytics and reporting methods.

Benefits

This project will benefit customers by allowing network operators to better utilise existing infrastructure owing to the availability of much richer data. This data will support the deployment of smart solutions which will in turn facilitate the adoption of low carbon technologies and the transition to a low carbon future.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Functional specification	Internal	36	£1.2m
Technical specification	Academic/Tech Provider		
Design and build (Software)	Internal/Tech Provider		
Test	Consultants		
Deploy	Internal		
Analysis	Internal/Academic		

Demand Side Response

Area	Customer service	**Objective**	• Commercial Innovation • Investment planning • Network Capacity
Expected Outcome		New commercial arrangements	
Consequence of not undertaking		Lost opportunity to develop a range commercial options for customers	

Background

The concepts of Demand Side Response (DSR) are well known following many years of academic investigation both in the UK and abroad. DSR encompasses a broad range of commercial arrangements across the complete energy supply chain and recent innovations such as Electricity North West's Capacity to Customers Project offering post-fault DSR have highlighted the unexploited potential for novel trading arrangements between all actors and the benefits returned to customers.

Proposal

This project will not fund any research into the concepts of DSR as they are already well known. It is intended to use the funding to continue the development of innovative contracts that will require both legal and commercial input to exploit opportunities presented by new technical developments.

Benefits

The benefits of DSR are many but the fundamental element is ensuring we can offer new high-value (to customers) services by exploiting network capacity based on physical limits rather than traditional passive network standards.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Staff development	Internal/Consultant	48	£2m
Investigation into commercial innovations	Internal/Consultant		
Investigation into legal innovations	Internal/Consultant		
Customer engagement	Internal/Consultant		

New Connections

Area	Customer service/ Affordability	**Objective**	• Commercial Innovation • Investment planning • Capacity thresholds
Expected Outcome		New connection arrangements based around commercial arrangements	
Consequence of not undertaking		Lost opportunity to develop a range commercial options for connection customers	

Background

Electricity North West has pioneered the relatively new area of commercial innovation in regard to new connections to our network with the specific aim of facilitating more cost effective and efficient connections of low carbon technologies for our customers. The connect and manage approach is a novel method of facilitating our customer's needs and the advent of advanced monitoring and data manipulation should allow this approach to be more widely extended.

Proposal

This project will continue to develop this and other methods of commercial innovation across all voltage levels and for all customer groups with the aim of ensuring Electricity North West can continue to deliver the most efficient service for our customers. The project will examine all elements of connection agreements and the opportunities afforded by new monitoring and control technologies and will identify the skill required by our staff to exploit new opportunities.

Benefits

Commercial innovation is as fundamentally important to the delivery of an efficient network as is technical innovation, and in some cases can deliver significant financial savings for customers. Benefits will result from ensuring we can explore all aspects of network operations to deliver the most effective commercial arrangements for our customers.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Review	Internal	36	£1.2m
Identification of skill sets required	Academic		
Customer engagement	Consultant		
Model contract development	Internal		
Financial appraisals	Internal		
BAU integration	Internal		

DSO Services

Area	Customer service	**Objective**	• Network design • operating standards • Commercial contracts
Expected Outcome		New DSO service specifications	
Consequence of not undertaking		Lost opportunity to understanding potential DSO role	

Background

The European Commission is prompting member states to develop their energy markets and regulatory regimes to facilitate the introduction of Distribution System Operator (DSO) services. According to the Union of the Electricity Industry European (EURELECTRIC) UK DNOs will face the new challenges of facilitating effective retail markets, in addition to undertaking their traditional roles of operating, maintaining and developing an efficient electricity distribution network. These retail markets will be where customers will be provided with options allowing them to seamlessly choose the best suppliers, tariffs and services best tailored to their needs.

Proposal

It is clear at the moment that this migration from a passive network owner to an integrated system operator will present many challenges within the UK regulator environment and whilst the objectives are fairly clear, the path to achieve these objectives is fraught with difficulty. This project will investigate how these services can be defined and developed and how Electricity North West can implement these customer offerings to ensure we can operate our business in response to new demands and customer behaviour. It is envisaged this activity will continue to develop throughout the RIIO period.

Benefits

The benefits from this project will arise from ensuring we can remain at the forefront of offering services our customers need.

Tasks

Tasks	Resource	Duration (months)	Indicative Costs
Definition of the DSO role	Internal/Consultant	36	£2.92m
Examination of current business structures and offerings	Internal/Consultant		
Customer engagement	Internal/Consultant		
Gap analysis	Internal/Consultant		
Identification of the skills and people required to effect these changes	Internal/Consultant		
Implementation and business development	Internal/Consultant		

High Performance Computing/ Data Manipulation

Area	Customer service	**Objective**	• Develop load models • Investment planning • Capacity thresholds
Expected Outcome		Data processing specification and application	
Consequence of not undertaking		Hinder the understanding of the manipulation of smart metering data	

Background

In order to manage the expected increase in electricity distribution loads the way networks are managed will need to change significantly. This will be based on both the amount of data gathered by monitoring and surveillance tools and the extent to which the network will be automatically managed by new protection and control algorithms. It is already apparent that the costs associated with managing the increasing levels of monitoring data being gathered using current IT infrastructure is prohibitive. Therefore a radically new approach will be required to analyse and act on greatly increased data volumes.

Proposal

High performance computer systems are obviously capable of processing significant amounts of information in very short time scales. This project is not to investigate the performance of these systems but rather to examine the costs and benefits of such approaches to electricity distribution network management. This project will investigate the analysis of Smart Meter data and the potential to use the data for network management purposes as new meters are rolled out across the geographical regions of our network.

Benefits

The new demands on electricity distribution networks as we move to the significant adoption of low carbon technologies and the exponential increase in data being generated by a range of sensors means that our current approach to data storage and management will be inadequate. This project will define the requirements for new systems and test and implement the necessary solutions.

Tasks

Tasks	**Resource**	**Duration (months)**	**Indicative Costs**
Project scoping	Internal	24	£0.82m
Investigation of the ‘state of the art’ of HPC systems	Academic/Tech Provider		
Investigation of data storage and hosting	Internal/Academic		
Trials and analysis	Tech provider		
Development of future proof HPC platforms	Tech provider/internal		

Annex 24: Pensions

Annex 24 and all associated appendices to Annex 24 have been redacted as they contain confidential information.

Annex 25: Finance

Annex 25 and all associated appendices to Annex 25 have been redacted as they contain confidential information.

ANNEX 26: COST IMPACT OF MOORSIDE NUCLEAR POWER STATION

Electricity North West Limited
Registered Office:
304 Bridgewater Place,
Birchwood Park,
Warrington,
Cheshire.
WA3 6XG.
Registered no: 2366949 (England)

Contents

1. Executive Summary

1.1 Background

NuGen are proposing to build a new nuclear power station near to the existing nuclear reprocessing plant at Sellafield, Cumbria. NuGen have submitted a modification application to National Grid Electricity Transmission (NGET) to commence the formal application process for a connection to the transmission network. NGET and Electricity North West are preparing a modification offer for approval by NuGen.

At present there is insufficient capacity at Sellafield on our network to connect the power station. The size of the station technically precludes connection at 132kV and significant reinforcement of the NGET transmission network will be required to facilitate the connection.

The reinforcement of the transmission network will significantly affect our existing distribution network in Cumbria.

2. Connection proposal

2.1 NuGen

NuGen is a UK nuclear company owned by GDF Suez and Iberdrola. NuGen are proposing to build a new nuclear power station on the west coast of Cumbria, near to the existing Sellafield reprocessing plant. The new site has been named Moorside.

NuGen have confirmed that the Moorside nuclear power station will have an export capacity of 3.6GW and use the Westinghouse AP1000 reactor.

NuGen are currently in the development phase of the Moorside project. It is NuGen's intention to complete the development phase in 2015; after which they intend to announce their formal decision to proceed with the project, or not.

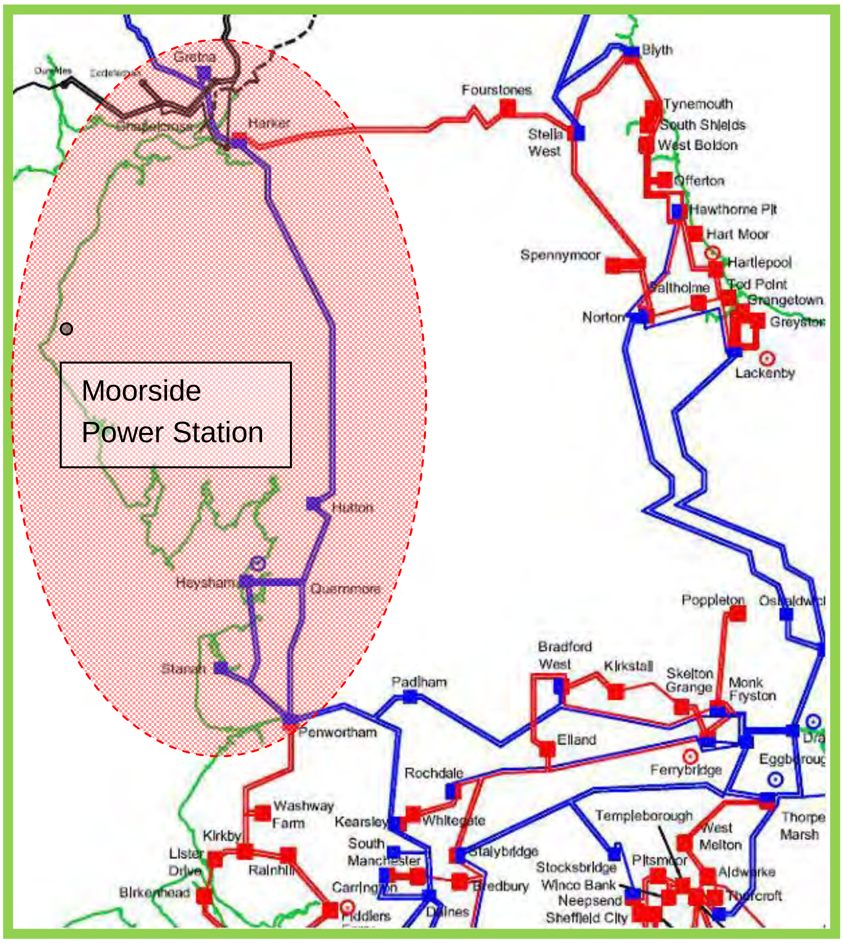
If NuGen proceed with the project construction is likely to begin in 2016-17. The target date for station operation is 2023 however construction and commissioning supplies would be required before this date.

2.2 National Grid Electricity Transmission (NGET)

NuGen have requested NGET to quote for the provision of (up to) a 3.6GW export capacity connection to the transmission network at Moorside.

The figure below shows the NGET transmission assets in the north of England and the location of the new power station. Due to the absence of transmission assets on the north west coast of Cumbria, the transmission network will require both extension and reinforcement in order to provide the required connection.

As the power station is nuclear, a minimum of four circuits are required to connect to the power station to provide the required level of safety resilience.



The NGET connection project (separately from the power station) is a major infrastructure project and will therefore require the consent of the Planning Inspectorate.

As part of the planning and consents process NGET have been engaging with local stakeholders over a three-year period to understand the constraints to establishing transmission circuits/ assets and to optioneer solutions.

Should NuGen confirm the power station project, NGET intend to apply to the Planning Inspectorate for consent in 2016. Construction is anticipated to commence in 2017. Completion is required for 2022 to allow operation in 2023.

2.3 Transmission Connection Options

The optioneering process undertaken by NGET in co-operation with us and regional stakeholders has been wide-ranging and has considered overhead lines, underground cables and subsea cables; AC and AC/DC solutions have also been considered.

Following consideration of the many options, on 22 October 2012, NGET announced that they are considering the following three options:

NGET Option 3

This option consists of a double circuit 400kV overhead line from Harker to Moorside and a double circuit 400kV overhead line from Moorside to Quermore, near Lancaster.

NGET Option 4a and 4b

These two options consist of a double circuit 400kV overhead line from Harker to Moorside and a double circuit subsea connection into the Fylde area from Moorside by one of the following methods:

Option 4a: A double 400kV circuit to Barrow and from Barrow across Morecombe Bay via a new tunnel.

Option 4b: Construct an AC/DC converter station at Moorside and a DC/AC converter station on the Fylde coast. Connect the converter stations via two DC subsea links.

2.4 Effect on Our Distribution Network

The above options represent our best view of the current status of the NGET optioneering process. All likely options will have a significant impact on our 132kV network. It is anticipated that much of our network in the line corridor will be affected to a greater or lesser degree. The lower voltage networks may in some areas need to be undergrounded where they are near to the proposed transmission lines or undergrounded for visual amenity if mandated as part of the consent proposal.

In undertaking their route corridor analysis NGET have identified that the overhead line routes that have the least visual impact are already occupied by Electricity North West 132kV lines. To secure planning consents for their 400kV transmission lines NGET will have to locate the lines in the best position aesthetically. This is expected to necessitate the removal of a significant proportion of our 132kV tower lines in Cumbria. To maintain existing customer supplies, NGET will have to construct new Grid Supply Points (GSPs) to feed our local networks.

It is estimated that approximately 214km of 132kV overhead line will have to be dismantled; to be replaced by three GSPs (Lindal, Sellafield & Seaton) and approximately 95km of 132kV cable.

In addition, there is significant expenditure associated with maintaining supplies whilst NGET completes its construction works. This involves the undergrounding of our overhead lines adjacent to the new 400kV lines and construction of temporary 132kV lines in order to facilitate dismantling of 132kV tower lines ahead of transmission energisation.

The removal of this amount of overhead line will affect our communications provision in the area as we will lose many of our fibre optic circuits used for protection and system management. These will have to be replaced with equivalent technology.

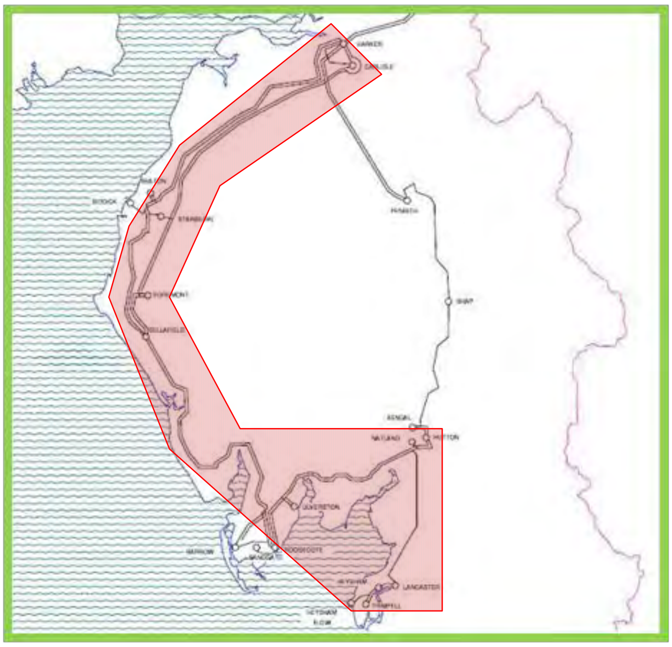
The changes to our distribution and communications networks will precipitate significant work to secure appropriate consents for our new assets.

It is likely that some of the assets that would be dismantled under the NGET connection option would have warranted replacement in any case in the RIIO-ED1 period. Therefore, a secondary effect to us is the impact on the asset replacement and maintenance programmes in RIIO-ED1. This represents a saving in capital expenditure; however remedial intervention will be required to ensure the security of the assets whilst NGET establishes their assets. In order to facilitate the necessary 132kV line outages, elements of our scheduled maintenance work will need to be brought forward. We anticipate that if this project goes ahead we would need to agree alternative secondary deliverables to as part of the RIIO-ED1 Output requirements. At this stage, we do not predict that this project will have a material impact on our primary outputs, with the potential exception of customer satisfaction and complaints which we cannot fully quantify at this point in time.

NGET has also discussed with environmental stakeholders and local planning authorities the undergrounding of existing overhead lines to mitigate the visual intrusion of the new transmission lines. This may include the undergrounding of a number of 132kV, 33kV and HV overhead lines that cross the river Eden to the northwest of Carlisle.

Whichever option NGET decide to progress, there will be a significant impact on our 132kV overhead line network as much of it will need to be dismantled to make way for the transmission assets needed. The figure below shows the scale of the potential effect of option 3 on our 132kV network.

Early indications are that the majority of our 132kV overhead line network within the indicated area will need to be dismantled to make way for the transmission assets. New GSPs are proposed for Lindal, Sellafield and Seaton. It is anticipated that a 132kV circuit connection to Barrow, Roosecote, Egremont, Siddick and the offshore windfarm Robin Rigg will be provided from the appropriate new GSP. In addition, if we establish a new BSP at Millom (132/11kV) this will need to be connected to one of the new GSPs or another new GSP dedicated to it.



2.5 Completing Table CV9b

The ‘best view’ solution is still in the development stage and it will be heavily influenced by stakeholders and the requirements imposed by the formal planning process. The implications of the nuclear site licence conditions for the existing customer Sellafield Limited will also be a key factor in the final project design.

For the purpose of completing of Table CV9b it has been assumed that NGET will develop a solution consistent with Option 3 above. It should be noted that this does not imply that this will be NGET’s chosen solution. It should also be noted that site licence considerations for Sellafield Limited have not been included at this stage, pending more detailed construction programme planning details being made available by NGET. The table commentary for CV9b provides further detail on the programme timescales.

For the purpose of completing the exit charges table, we have assumed that all changes are driven by NuGen’s connection application to NGET and hence we have included no Moorside-related exit costs in CV108.

Our discussions with NGET indicate that three additional Grid Supply Points will be established, namely Sellafield, Seaton and Lindal.

We have not included the associated costs in table C34 as the Moorside connection is not is our Best View submission. We have outlined below our estimate of such costs together with their associated profile should the connection proceed. In this event these would be actual additions to C34 as part of the uncertainty mechanism. Appendix 1 provides the detailed breakdown of the costs.

Year	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	RIIO-ED1
Cost (£m)	0.0	0.0	0.0	0.0	7.1	7.1	7.2	7.3	28.8

Whilst NuGen may make a parallel connection application to Electricity North West for site construction supplies we do not forecast that this would trigger the need for reinforcement of at GSP level.

We continue to undertake discussion with NGET to understand the impact on our network and to agree cost apportionment principles. In developing our forecast we have assumed that North West customers would only pay for the on-going assets that they use and benefit from, for example replacing old assets close to end of life with brand new ones or any change in reliability as a result of the project. We have assumed that North West customers would not pay for any 400kV assets, any dismantlement costs or any temporary or enabling works. Any works to be undertaken by us but not funded by North West customers have been categorized as Non-Trading Rechargeables (NTR) for the purposes of this forecast and are assumed to be fully funded by NGET (income reported as customer contributions in template).

Our project costs are therefore detailed under two broad categories; Regulatory Asset Value (RAV) and NTR. Costs detailed as RAV are associated with the provision of new Electricity North West distribution network assets ie substations, switchgear, line and cables. Costs detailed as NTR are associated with the dismantlement of existing distribution network assets, diversions (incl. undergrounding of existing overhead lines), erection and removal of temporary circuits and engineering support to NGET.

Associated costs detailed in the table include:

- Wayleave/consent – costs incurred in acquiring all necessary wayleaves/ consents.
- Fibre communications – costs incurred to maintain IT&T fibre communications links and telecommunications links.

2.6 Costing methodology

In pricing the work required to complete our component of the Moorside connection we have carefully considered each element of the scheme scope and determined the value by utilising current market costs, consistent with the unit rates detailed in table CV3.

Market testing of the unit rates on which the costings are based has been undertaken via analysis of competitively tendered projects and comparison with actual costs from similar projects undertaken by our framework contractors.

It is of note that as outlined above the scope of work remains subject to very significant variation and hence our costing work is at this stage indicative only.

Given the scale of the required work, many elements of the programme would be competitively tendered as a means to test the market, searching for spare capacity from both local and national contractors. The rationale behind this dual approach was to validate current framework arrangements against a changing and competitive market place ensuring that the rates proposed are the most cost efficient available.

The total programme value is the summation of the direct build cost, together with a forecast of the extra indirect costs which are required. As with the direct costs assessment, we have reviewed our indirect costs element and a separate bespoke forecast has been included aligning to the particular requirements of the project.

By utilising rates comparable to our asset replacement forecast (CV3) and a bespoke assessment of indirect costs we consider the costing approach for Moorside project will be highly competitive, and offers value for money.

Appendix 1 – breakdown of potential future Exit Rate charges

Figures are in outturn prices		Total Charge 2015/ 2016	Total Charge 2016/ 2017	Total Charge 2017/ 2018	Total Charge 2018/ 2019	Total Charge 2019/ 2020	Total Charge 2020/ 2021	Total Charge 2021/ 2022	Total Charge 2022/ 2023	Total RIIO ED1
Lindal	Electronics associated with SGT1	0	0	0	0	11,347	11,333	11,310	11,276	45,266
Lindal	Electronics associated with SGT2	0	0	0	0	16,610	16,590	16,556	16,507	66,264
Lindal	Electronics associated with SGT3	0	0	0	0	22,015	21,988	21,943	21,879	87,825
Lindal	Non-Electronics Associated with SGT1	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Lindal	Non-Electronics Associated with SGT2	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Lindal	Non-Electronics Associated with SGT3	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Lindal	180 Double Busbar Bay	0	0	0	0	193,309	195,722	198,122	200,507	787,660
Lindal	280 Double Busbar Bay	0	0	0	0	183,705	185,998	188,279	190,545	748,526
Lindal	380 Double Busbar Bay	0	0	0	0	192,086	194,485	196,870	199,239	782,679
Lindal	H10 Double Busbar Bay	0	0	0	0	313,908	317,827	321,724	325,596	1,279,054
Lindal	H20 Double Busbar Bay	0	0	0	0	313,908	317,827	321,724	325,596	1,279,054
Lindal	H30 Double Busbar Bay	0	0	0	0	313,908	317,827	321,724	325,596	1,279,054
Lindal	SGT1 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Lindal	SGT2 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Lindal	SGT3 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Lindal	SGT1 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Lindal	SGT2 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Lindal	SGT3 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Lindal	SGT1 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Lindal	SGT2 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Lindal	SGT3 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Sellafield	Electronics associated with SGT1	0	0	0	0	11,347	11,333	11,310	11,276	45,266
Sellafield	Electronics associated with SGT2	0	0	0	0	16,610	16,590	16,556	16,507	66,264
Sellafield	Non-Electronics Associated with SGT1	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Sellafield	Non-Electronics Associated with SGT2	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Sellafield	180 Double Busbar Bay	0	0	0	0	193,309	195,722	198,122	200,507	787,660
Sellafield	280 Double Busbar Bay	0	0	0	0	183,705	185,998	188,279	190,545	748,526
Sellafield	H10 Double Busbar Bay	0	0	0	0	313,908	317,827	321,724	325,596	1,279,054
Sellafield	H20 Double Busbar Bay	0	0	0	0	313,908	317,827	321,724	325,596	1,279,054
Sellafield	SGT1 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Sellafield	SGT2 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Sellafield	SGT1 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Sellafield	SGT2 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Sellafield	SGT1 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Sellafield	SGT2 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Seaton	Electronics associated with SGT1	0	0	0	0	11,347	11,333	11,310	11,276	45,266
Seaton	Electronics associated with SGT2	0	0	0	0	16,610	16,590	16,556	16,507	66,264
Seaton	Non-Electronics Associated with SGT1	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Seaton	Non-Electronics Associated with SGT2	0	0	0	0	13,937	14,111	14,284	14,456	56,787
Seaton	180 Single Busbar Bay	0	0	0	0	94,185	95,361	96,530	97,692	383,769
Seaton	280 Single Busbar Bay	0	0	0	0	94,185	95,361	96,530	97,692	383,769
Seaton	SGT1 400kV Connection	0	0	0	0	434,925	440,355	445,755	451,119	1,772,155
Seaton	SGT2 400kV Connection	0	0	0	0	434,925	440,355	445,755	451,119	1,772,155
Seaton	SGT1 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Seaton	SGT2 400/132kV 240MVA	0	0	0	0	365,242	369,802	374,337	378,842	1,488,224
Seaton	SGT1 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Seaton	SGT2 400kV 240MVA Cable 100m	0	0	0	0	78,471	79,451	80,426	81,393	319,742
Seaton	SGT1 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Seaton	SGT2 132kV 240MVA Cable 100m	0	0	0	0	26,157	26,484	26,809	27,131	106,581
Total		0	0	0	0	7,066,412	7,153,187	7,239,390	7,324,925	28,783,914

ANNEX 27: CORPORATE GOVERNANCE, COMPLIANCE AND DATA ASSURANCE BUSINESS PLAN ANNEX

Electricity North West Limited
Registered Office:
304 Bridgewater Place,
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Warrington,
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WA3 6XG.

Registered no: 2366949 (England)

Contents

1. Executive Summary

1.1 Corporate Governance

Electricity North West takes its role as a public service provider very seriously and recognises the responsibilities associated with our position. We adopt the highest levels of corporate governance to protect our customers and stakeholders. The first part of this document provides an overview of the governance structures in place to ensure that our business is appropriately governed.

1.2 Submission Assurance

Equally, we take our regulatory reporting responsibilities seriously. Regulatory assurance forms a central part of our wider assurance processes.

As part of our early planning processes, we identified the Well Justified Business Plan (WJBP) submission as a significant, high process risk publication and recognised the potentially significant implications for our customers if we got things wrong. We therefore commenced our data and process assurance planning for this publication in 2011 and have committed significant resources into the development and assurance of our plan.

The WJBP submission comprises a combination of historic actual data, current year data and forecast data; these aspects require quite different assurance processes. Our governance process for the plan is consistent with other significant regulatory submissions, including assurance checks, second person review, internal expert reviewers, risk-based audits and ultimately, approval by the Electricity North West Board.

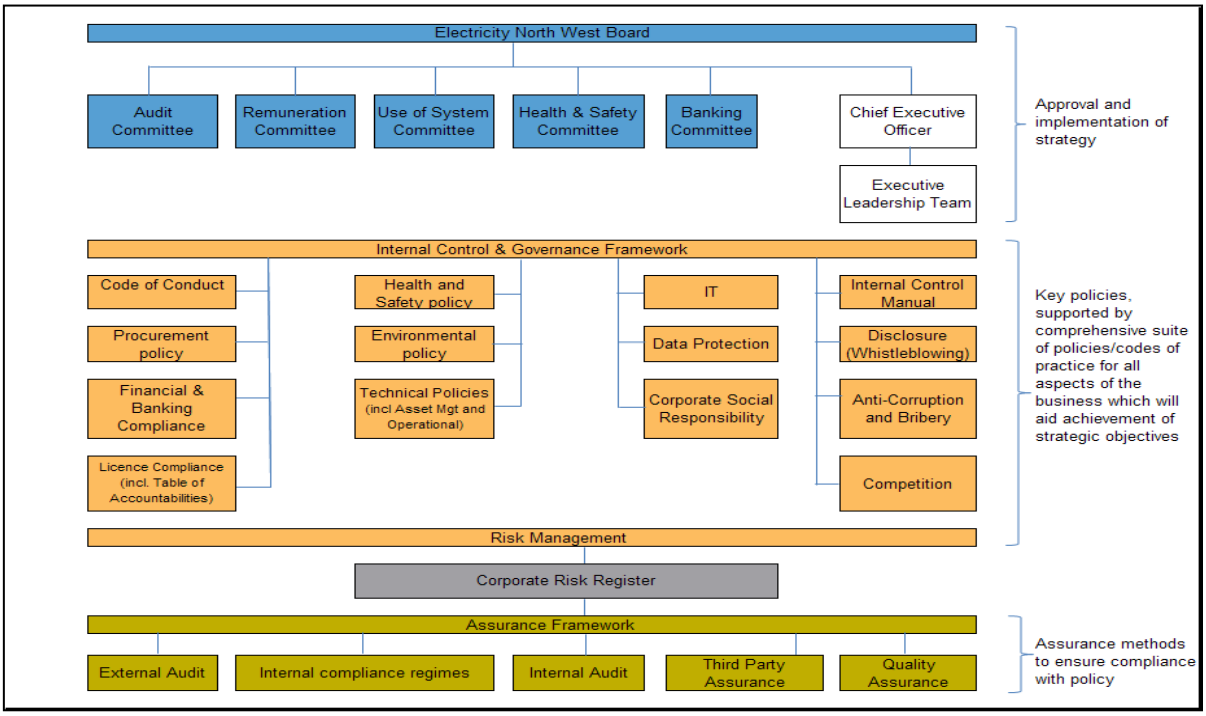
This document provides a high level summary of the data assurance processes applied to all aspects of our plan.

2. Electricity North West Corporate Governance

2.1 Overview

This chapter details the corporate governance statement for Electricity North West Limited.

The figure below summaries the key components of the governance framework. The coverage and content of the framework is similar to that which a quoted company is required to hold under UK Corporate Governance Code (the Code).



2.2 Compliance Statement

The Financial Conduct Authority's Listing Rules require UK quoted companies to explain to shareholders how they have applied the 'Main Principles of the Code' or explain why they have not done so.

The intention of the Code is that companies should be able to explain their governance in the light of the principles that have led them to a particular approach. The Directors are of the opinion that, in the instances where the Company does not comply with certain provisions of the Code, the approach is justifiable given the privately held nature of the Company and that the provisions of the Code are disproportionate or less relevant in our case.

We have set out below and in the following pages our compliance with the main principles of the Code and explain any areas of non-compliance.

2.3 Leadership and Effectiveness

2.3.1 The Role of the Board

The Company's strategy is to become the leading energy delivery business, measured against the following strategic objectives:

- Understand and Influence the Market;
- Understand and Deliver for Customers and Stakeholders;
- Develop a High Performance Organisation; and
- Deliver Sustainable Growth with Robust Financial Performance.

The Board's role is to ensure the Company is equipped to deliver this strategy both today and in the long term. To ensure that it achieves this, the Board meets regularly to provide leadership, set strategic direction and objectives and ensure that appropriate financial and other resources are made available to enable the Company to meet those objectives. The Board has agreed its Business Plan to ensure the Company's strategic objectives are delivered through:

- A stable financial structure, providing necessary financing to support business operations;
- Improved financial performance that meets financial covenants governing the business;
- Sustainable dividend profile while retaining gearing within the target level; and
- Capital and maintenance plans that deliver financial and network outputs in line with regulatory contract commitments.

In addition, the Board oversees the work of the Audit Committee in drawing up and maintaining a framework of controls that assess and manage the risks the business is exposed to. This is discussed in more detail later in this Annex.

The Company has identified a number of key areas that are subject to regular reporting to the Board. There is in place a schedule of decisions reserved for the Board which includes: strategy approval and management; succession planning; business plan approval; internal controls; Company policies and delegation of authority. Projects and contracts have various limits of approval to Board level.

2.3.2 Board Committees

The terms of reference of each Committee are available to the shareholders of the Company and can be obtained by written request from the Company's registered office, with the exception of the Audit Committee terms of reference which is available on our website.

<u>Audit Committee and Auditors</u>

The activities of the Audit Committee are discussed in more detail in section 2.3.15. The committee is attended by designated Directors of the Board.

<u>Remuneration Committee</u>

The activities of the Remuneration Committee are discussed in more detail in section 2.3.10. The committee is attended by designated Directors of the Board.

<u>Health and Safety Committee</u>

The remit of the Health and Safety Committee includes: setting the health and safety strategy, objectives and targets; reviewing and monitoring performance and reporting to the

Board. The committee is attended by designated Directors of the Board and of the Executive Leadership Team.

Financing Committee

The Financing Committee was constituted as a formal committee of the Board in December 2012. Duties include assisting the board in overseeing the financial risk management strategy and treasury matters delegated to it by the Board and approving major financial transactions on behalf of the Board.

The committee is attended by designated Directors of the Board.

Use of System Pricing and Banking Committees

In addition to the above, there are two executive committees of the Board. The Use of System Pricing Committee meets to approve all the prices contained in the Standard Licence Condition 14 statement.

The Banking Committee met once during the year and has been established to deal with banking matters.

Non-Standing Committees

As the need arises, non-standing committees are established to deal with special issues. An example of such is the training centre committee which met to approve the purchase and funding of a training facility.

2.3.3 The Chairman and Division of Responsibilities

There is a clear division of responsibilities between the Chairman and the Chief Executive and these responsibilities are set out in their respective contracts. An independent non executive Chairman was appointed with effect from 1 March 2014 and fulfils the independence criteria detailed in the Code.

However, in January 2013 Ofgem published its formal licence modifications for conditions in all of the network operator licences. One of the requirements will be for an operator to have two sufficiently independent directors on their Board. Directors will not be considered "sufficiently independent" where they are directors or employees of any company which has any of the same ultimate controllers as Electricity North West Limited, unless that company has a gas transporter, electricity transmission or distribution licence. Nor can directors sit on any holding company unless its sole holding is the licensee and other wholly owned subsidiaries having such a licence.

This licence condition will come into effect on 1 April 2014. We have therefore reviewed the composition of its Board and the independence of its Non Executive Directors and its Chairman to ensure compliance with the Licence Condition and the Code.

The Chairman, with the assistance of the Company Secretary, sets the board agenda and ensures the board receives accurate, timely and clear information to enable sound decision making and effective monitoring.

2.3.4 Non-Executive Directors

Non-executive directors participate fully in discussions on strategy and are responsible, through the Remuneration Committee, for Executive Directors' remuneration, appointments and succession planning for the Executive Leadership Team.

As there are representatives of both shareholders on the Board, it has not been considered necessary to appoint a Senior Independent Director to be available to shareholders as required by section A.4.1. of the Code.

2.3.5 Composition of the Board

Two of the Directors fulfil the requirements of independence as set out in the Code. There are four additional Non-Executive Directors on the Board, each of whom represents one of the Company's ultimate shareholders. The Company believes that these Directors, together with the Chief Executive Officer and Chief Financial Officer, are a good balance of Executive and Non-Executive representation to enable the Board and its Committees to discharge their duties effectively and to ensure that no individual or small group of individuals can, or do, dominate the Board's decision making. In addition, employees have been included in the membership of the Health and Safety Committee in order to further enhance the effective discharge of these respective responsibilities.

The Company is not an equity listed company and therefore the quota of Independent Directors listed in the Code, section B.1.2, is not considered appropriate for the Company, having regard to its privately held status.

2.3.6 Appointments to the Board and Board Member Commitment

The Board is satisfied that the process of appointing new Directors to the Board is formal, rigorous and transparent. Succession planning is in place for the Executive Leadership Team and senior management to ensure the Company has the appropriate mix of skills and experience.

It is the Company's aim to ensure an appropriate level of diversity in the Boardroom as vacancies arise. Appointments are made on merit, taking into account relevant skills, experience, knowledge, ethnicity and gender. These issues are also taken into consideration by shareholders when appointing their representatives to the Board.

The strength of the Board is vital and the overriding aim in any new appointment will always be to select the best candidate to support the achievement of the Company's objectives.

There is no formal Nominations Committee for the appointment of Directors and the Company does not comply, therefore, with the sections of the Code (B.2.1, B.2.2, B.2.4, B.3.1 and E.2.3) which deal with Nomination Committees.

The Remuneration Committee has been delegated this function by the Board and in any appointment of an independent Non-Executive Director, an external recruitment company is used.

The terms and conditions of Non-Executive Director appointments are made available to shareholders. The expected time commitment is conveyed to Directors, either in written or verbal form and all Directors confirm that they have sufficient time to fulfil the role. The Board is regularly updated on other significant appointments undertaken by any Director.

2.3.7 Development, Information and Support

New Directors are given an induction on joining the Board, detailing the Company's business, corporate governance and reporting procedures. This induction process is tailored to the skills, knowledge and experience of the individual and is designed to enable them to discharge their duties effectively.

All Directors receive comprehensive information on a regular basis. Board papers are distributed via the Company Secretary's office sufficiently well in advance of the relevant meeting to allow time for Directors to be fully briefed. The papers are detailed enough to enable the Directors to obtain a thorough understanding of the management and financial performance of the Company and its business. In addition, two-day Board meetings are held throughout the year to enable Directors to better understand major projects or processes in more depth. Meetings with senior management together with asset tours are undertaken to assist in their knowledge of the business.

The Company Secretary assists with professional development when required and advises on governance matters both on an individual basis and in the form of papers to the Board.

All members of the Board have access to independent professional advice at the Company's expense where they consider it necessary to fulfil their responsibilities.

2.3.8 Evaluation

A Board evaluation was conducted by Ffion Hague of Independent Board Evaluation in May 2011 and the Board has continued to build on the process undertaken at that time. The findings have been widely discussed and the Board will continue to undertake self evaluation and development initiatives to ensure members continue to enhance their skills and expertise with regard to their Board responsibilities.

2.3.9 Re-election of Directors

As a private company, the Company is not required to hold Annual General Meetings unless requested by the shareholders. The Articles of the Company do not require that Directors retire by rotation. The Company has strong links, however, with its ultimate shareholders: Board membership includes shareholder representatives and although the Company is not compliant with section B.7. of the Code due to its private status, shareholders are involved in Director appointments to at least as great an extent as if re-election took place at an AGM.

Should any Executive Director serve as a Non-Executive Director elsewhere in a situation where remuneration would be provided for that role, a decision would be made as to whether the director was authorised to retain that remuneration.

2.3.10 Remuneration Level and Components

The primary principle for the Company's remuneration policy is that remuneration and other terms of employment shall be fair and competitive to attract, retain and motivate Executive Directors ('Executives') of sufficient quality to deliver the objectives of the Group.

As a private Company, a remuneration report is not required to form part of the Company's Annual Report and therefore the Company does not comply with section D.1.2. of the Code.

The Remuneration Committee is careful to ensure that compensation arrangements in Executives' terms of appointments are appropriate, reward good performance and safeguard against rewarding poor performance. Notice periods are set at one year or six months.

Performance-related elements of remuneration formed a significant portion of the total remuneration package of the Executive Directors in the last year and these are linked to both corporate and individual performance objectives.

2.3.11 Remuneration Procedure

The Remuneration Committee sets the policy and procedures for Executive remuneration and for setting the remuneration packages of Executive Directors. No Director is involved in setting his or her own remuneration.

The Committee has responsibility to make recommendations to the Board on the policy and framework for the remuneration of the Executive Directors, approve employment related benefits for other Company employees and implement employees' bonus and long term incentive plans. The Remuneration Committee has responsibility for setting remuneration and succession planning for the Company's Executive Team.

Share options are not offered as an incentive to Executives or Non-Executive Directors as the Company is private. Remuneration for Non-Executives is reviewed by the Remuneration Committee, which ensures that this reflects the time commitment and responsibilities of the role.

2.3.12 Financial and Business Reporting

The Board takes seriously its responsibility to ensure that a balanced and understandable assessment of the Company's performance, position and prospects is given in the Annual Report and in any other report published by it for Ofgem or other stakeholders as necessary.

2.3.13 Internal Control Framework

The Board is responsible for the Group's system of internal control and its ongoing review. There is a continuous process for identifying, evaluating and managing the significant risks faced by the Company. This internal control framework is reviewed regularly by the Board and accords with the revised Internal Control: Guidance to Directors (formerly the Turnbull guidance).

The internal control framework is designed to identify and manage the principle risks and uncertainties of the business to achieve the Group's business objectives and can only provide reasonable, and not absolute, assurance against material misstatement or loss.

The key features of Electricity North West's internal control framework are:

- The highest standards of behaviour are expected from our employees. At Electricity North West we are proud of our strong commitment to having high ethical standards in the way that we work. We have outlined what those principles are in our Employee Code of Conduct document, which summarises our approach to doing business. All our employees must act in accordance with those principles.
- Engagement and commitment are obtained from all levels of the organisation in order to promote a strong control environment with clearly defined accountabilities

and organisation structures, operating within a framework of policies and procedures covering every aspect of the business.

- Comprehensive compliance regimes are in place to help ensure that the business meets its various financial, statutory and regulatory obligations.
- A well established 'Table of Accountabilities', which is updated (as a minimum) annually, is in place which details the obligations under the standard and special licence conditions that we must adhere to. It outlines who has specific accountability for compliance with each of our licence conditions.
- Comprehensive business planning, risk assessment and financial reporting policies and procedures are in place. They include the annual preparation of detailed operational budgets for the year ahead and projections for subsequent years.
- A Capital Programme Management Group and Project Approvals Group with defined policies and procedures, for planning, approving and monitoring major capital investment projects, provide effective governance in this area.
- Monthly reporting of financial and non-financial performance to the Board and Executive Leadership Team. Reviews are made of monthly performance against budgeted and targeted performance.
- A detailed Internal Control Manual is maintained, acting as the cornerstone of the internal control framework, which our employees are required to adhere to.
- The Risk, Control and Assurance team has responsibility for independently assessing the adequacy and effectiveness of the management of significant risk areas and internal control. This ongoing assessment helps to inform our annual risk-based audit strategy and plan.
- A designated audit team reporting to the Head of Health, Safety and Environment serves to monitor the effectiveness of our key Health and Safety controls and reporting processes, overseen by a committee of the Board.
- The Disclosure ('Whistleblowing') policy for Electricity North West seeks to ensure that any employee may voice any concerns about particular incidents of wrongdoing, or other suspected malpractice, without fear of criticism or future discrimination, provided that any matters raised are in good faith.
- Formal briefings are provided to our employees on key areas of the internal control framework in order to promote understanding and commitment, and relevant information is included within induction for new employees.

2.3.14 Risk Management

At Electricity North West our aim is to be a company where risk management is embedded in our culture, protects our reputation, enhances our performance and is central to us achieving our overall company vision 'to be the leading energy delivery business'.

Core to achieving this is our belief that all employees can play their role in identifying and managing risk.

The Company has a well embedded structure and process to help identify, access and manage risks, forming key elements of the risk management system.

The risk management system has been externally validated during the year as being in accordance with ISO 31000 'Risk Management - Principles and guidelines'.

The key features of the risk management system are as follows:

- Mandate and commitment demonstrated through the risk management policy statement and endorsed by the Executive Leadership Team.
- Clear risk management strategy in place to support continual improvement.
- Roles and responsibilities clearly defined to ensure effective ownership and delivery of risk management.
- Appropriate operational and non-operational risks are managed on a single corporate risk register which is maintained by the Head of Risk, Control and Assurance.
- The corporate register is underpinned by a number of ‘local’ risk registers in various areas of the business. Key risks on these ‘local’ registers are fed into the corporate risk register as they are identified.
- Each risk on the corporate register is designated to a member of the Executive Leadership Team who has the overall responsibility for managing that risk.
- All open risks, associated controls and mitigating actions are reviewed on a monthly basis as part of a well embedded risk monitoring process.
- A network of risk co-ordinators has been established to enhance the risk monitoring process. Importantly this strengthens risk accountability within the business. This group meets formally on a bi-monthly basis.
- Quarterly risk workshops are held with the Executive Leadership Team in order to review the key risks that appear on the corporate register and discuss any emerging risk themes.
- An annual risk review is formally held with the Electricity North West Board.

2.3.15 Audit Committee and Auditors

The main purpose of the Audit Committee is to review and maintain oversight of our corporate governance, particularly with respect to financial reporting, internal control and risk management.

The Committee meets regularly during the year aligned to the financial reporting timetable. Significant Board member time is also spent at meetings with executive management, understanding the key issues and underlying processes, setting agendas and meeting with auditors.

The Committee consists of Non Executive Directors with relevant experience with one being Independent. Therefore we comply with the Disclosure and Transparency Rule 7.1.1 to have one Independent Non Executive Director, but not with the requirement of section C 3.1 of the Code which requires three. The composition is considered by the Board however, to be objective and effective given the Company’s private ownership, shareholder representatives on the Committee, input from Executives and the external auditors.

By invitation, Audit Committee meetings are regularly attended by the Chief Executive Officer, the Chief Financial Officer and the Head of Risk, Control and Assurance and representatives from the external auditors, Deloitte LLP. The Committee also meets privately, without any member of the management present, with both the internal auditor and external auditors.

Minutes of the Committee meetings are made available to the Board. Additionally, the Chairman of the Committee reports to the Board after each meeting on any issues where action or improvement is required.

The main role and responsibilities of the Audit Committee are set out in its terms of reference and include those items detailed in section C 3.2 of the Code, except that the Company does not hold an AGM and therefore the appointment external auditors are approved by the Board based on the review and recommendations of the Audit Committee.

The Committee's principal responsibilities include:

- Monitoring the integrity of the financial statements of the Company, including its annual and half yearly reports and any other formal announcements relating to its financial performance.
- Reviewing and monitoring the effectiveness of the Company's internal control and risk management systems.
- Reviewing whistleblowing arrangements.
- Considering the appointment, re-appointment, fees and removal of the external auditor and making necessary recommendations to the Board.

In December 2012 the Board reviewed the terms of reference in light of the Financial Reporting Committees' Guidance on Audit Committees and the revised UK Corporate Governance Code issued in September 2012. Going forward, the Committee will ensure that the external audit contract is put out to tender at least once every ten years. The Committee will also advise the Board on whether, taken as a whole, the Company's financial reporting is fair, balanced and understandable and provides the information necessary to assess the Company's performance, business model and strategy.

2.3.16 Work of the Audit Committee

During the last financial period, key areas of focus for the Audit Committee included:

- Internal Controls – continued monitoring and review of the Company's system of internal controls, taking account of the findings of both internal and external audit reports.
- Risk Management – monitoring the process for managing ENWL's significant risks, including regular presentations and reporting from the Head of Risk, Control and Assurance. A risk review was also completed by our Board, feeding in to the work of the Committee.
- Relationship with External Auditors – overseeing the Company's relationship with the external auditors, including recommending reappointment, the scope and approach to their work, their fees, performance, expertise, objectivity and independence (including the approval and compliance with the Company's policy on non-audit work).
- Financial Reporting – reviewing the Group's financial statements, including reports from management and from the external auditors regarding compliance with accounting standards, key judgements made in preparation of financial statements and compliance with legal and regulatory requirements.
- Internal Audit Workplan – overseeing the work of internal audit, including approval of the plan of work for the period and resulting actions and recommendations.

2.3.17 Provision of Non-Audit Services

To ensure external auditor independence and objectivity, the Company has in place a policy for the provision of non-audit services by the external auditor, which is managed by the Audit Committee. The policy defines the nature of non-audit work that may be undertaken in order that auditor independence is maintained. The Committee is required to authorise any work not falling into the permitted categories defined in the policy or falling above a financial limit of £250,000.

Proposed work is reviewed for compliance with regulatory requirements that preclude auditors from performing certain types of work and to assess if the nature of the work would create a conflict of interest. The Committee is updated on the nature, cumulative costs and extent of non-audit services provided by the auditors.

2.3.18 Internal Audit

All internal audit activity is conducted by a single team under the leadership of the Head of Risk, Control & Assurance. The role has a dual reporting line into the Audit Committee Chairman and the Chief Financial Officer. The Risk, Control & Assurance team has responsibility to the Audit Committee for agreement of the annual risk-based audit strategy and plan, providing regular updates on findings and progress against the plan. The audit strategy is subject to robust review each year in order to ensure that the plan addresses key areas of focus for the business.

A formal quarterly meeting between the Head of Risk, Control & Assurance and the Audit Committee Chair takes place outside of the formal Audit Committee meetings in order to discuss findings and progress against and adequacy of the annual plan, and ensure sufficient resources are in place.

The Risk, Control and Assurance team comprises both financial and operational expertise and works closely with related areas of assurance and compliance activity within the business, including legal, health and safety and regulation.

When issues or control deficiencies are identified during audit engagements, the Risk, Control & Assurance team works with business managers to develop corrective action plans to address the causes of non-compliance and gaps in internal controls. The team employs a rigorous monitoring process to track these plans to completion and report results on a monthly basis to the Executive, and at each Audit Committee meeting.

To supplement the internal skills required to complete the audit programme, the Group uses external financial and operational professionals, where appropriate, to provide independent assurance of internal control processes in accordance with a pre-defined scope.

In compliance with the Code, the Board regularly and at least annually reviews the effectiveness of the Company's system of internal control. The Board's monitoring covers all controls, including financial, operational and compliance controls and risk management. It is based principally on reviewing reports from management to consider whether significant risks are identified, evaluated, managed and controlled and whether any significant weaknesses identified are promptly remedied or managed by more extensive monitoring. The Audit Committee assists the Board in discharging its review responsibilities.

2.3.19 Relationship with shareholders

Electricity North West Limited is a private company and the ultimate holding Company, North West Electricity Networks (Jersey) Limited, has just two major shareholders. Board membership includes four Non-Executive Directors taken proportionately from both the Company's ultimate shareholders. The Board as a whole therefore has a full understanding of the views of the major shareholders of the Company including on strategy and governance.

The Company's relationship with the shareholders as described above is a strong one not requiring a formal AGM as outlined in section E.2 of the Code.

3. Compliance and Data Assurance

3.1 Introduction

We strive to employ the highest standards of corporate governance commensurate with our status as a public interest entity. Consistent with this, we take regulatory compliance and assurance seriously. We have always considered that Electricity North West has a series of robust processes in place and therefore we are pleased to attach our summary of the assurance process for our Business Plan.

Our approach to assuring our WJBP was based on the existing processes in our business that individually and collectively assure our regulatory data on a routine basis. These processes form an integral part of our corporate governance and control framework that encompass our risk management, assurance and compliance processes.

3.2 Purpose of the Report

This report sets out the approach we take to produce a business plan submission which customers and stakeholders (including Ofgem) can rely upon.

3.3 Structure of the Report

This report describes the assurance activities undertaken for the various documents that comprise our WJBP submission. Section 4 describes our overarching approach to compliance and assurance within the business and details the processes and assurance activities undertaken from the development through to the publication of the business plan.

3.4 High Level View of Overall Company Approach to Governance

The assurance plan for the business plan submission was developed and conducted in the wider context of our corporate governance and control processes. These processes are well established and are Board led – with Non Executive Directors playing important roles in leading our governance and control processes.

Our internal control and governance framework outlines our approach to governance, internal control and assurance. Regulatory assurance forms a central part of this and is firmly embedded within our wider assurance processes.

Our corporate internal control and governance framework is further enhanced by our corporate values within which Honesty and Professionalism are central to the way in which our people work.

3.5 High Level View of Overall Approach to Regulatory Submissions.

Electricity North West's only business is being a Distribution Network Operator. Key value drivers for our business are regulatory measures and as such our business is substantially operated based on regulatory data.

Our key performance indicators, including our company scorecard, include several regulatory measures. These are reviewed regularly by our Board and our Executive Leadership Team (ELT) which includes all the directors reporting into the Chief Executive Officer. This means that a substantial proportion of our key regulatory data is reported regularly rather than being only collated at a year end.

We regularly undertake ongoing improvement activities that enhance the robustness of our data and reporting processes. All of these improvements seek to further align business information with regulatory reporting requirements.

To ensure that senior managers are aware of the importance of regulatory compliance and reporting, regular briefings and interviews are conducted. The Electricity North West Limited Board was advised of Ofgem's new requirements for Data Assurance at the Board meeting in January 2013.

3.6 Clear Accountabilities

Our regulatory compliance and assurance processes ensure that accountability for regulatory compliance is clear, processes are robust and employees have access to the information they need to understand their role.

Our processes include clear accountability for compliance with each licence condition through a formalised table of accountabilities, with each licence condition being assigned to an accountable member of our Executive Leadership Team (ELT), and senior managers identified as being accountable for strategy and implementation. These accountabilities are reviewed when the organisational structure changes. The most recent review was completed in January 2013. Interviews with accountable ELT members and senior managers are undertaken regularly to review compliance status.

3.7 Compliance Processes

Our compliance processes prescribe minimum assurance of all submissions including documented methodologies, assurance by component reviewer, sign off of each submission by an accountable senior manager (up to and including a Board Director) and formal review of compliance and reporting processes.

Our process includes specific arrangements necessary to cater for very large submissions (such as the WJBP and Regulatory Reporting Pack (RRP), where it is appropriate to detail accountabilities to table level) and for frequent submissions. Where data is required from many teams across our business, our processes are designed to make accountability of wider contributors clear whilst also ensuring overall ownership of each table.

In addition, based on the assessed risk of the requirement, we also supplement these minimum standards with specialist internal expert review and with both internal and external audit, in line with our overall risk and audit strategy.

One of our key areas of focus over recent years has been recognising the importance of employee engagement and ownership of regulatory reporting. Our embedded compliance processes are supported by an ongoing process of briefings and accountability interviews that further serve to promote understanding, engagement and commitment amongst our employees responsible for licence compliance.

We also undertake face-to-face briefing of appropriate employees. These are tailored for teams and place the requirements on them in the wider context of our 'regulatory contract'.

Our company bonus is also linked to the regulatory performance of the business. By aligning the company performance with rewards, employees are encouraged to improve customer and network performance.

4. Assurance Undertaken

4.1 Approach to Assuring our Business Plan.

The WJBP submission comprises a combination of historic actual data, current year data, forecast data and supporting analysis. This report covers all four areas and describes the data assurance processes attached to each area. The nature of the submissions requires quite different assurance processes for the different datasets. Whilst data assurance regimes have been in place for the reporting of actual data (involving a combination of sign off, review, internal and external audit and assurance), new processes put in place for the forecast tables were maintained. Assurance of actual data and forecasts is different in nature. Our assurance process ensures:

- Historic audited data is accurately represented
- The forecasts within the WJBP are robust and internally consistent.
- Assumptions used are sound and costs/volumes have fed through accurately.
- The current year actual data is consistent between the RRP and the business plan.

Our preparation for this submission has built upon the WJBP submitted to Ofgem in July 2013. The majority of the processes developed for that submission have been adopted for this business plan.

4.2 Business Plan Data Tables

The business plan tables are a combination of actual performance and forecasts. These different numbers require different assurance processes to ensure that a robust plan is produced.

4.2.1 Historic Data

Data submitted to Ofgem for historic years (2010-11, 2011-12 and 2012-13) was reviewed prior to its original submission through our internal assurance process, supported by targeted external data and process audits by specialists (including KPMG, ERM CVS, Mike Dixon Limited etc). Submissions have been reviewed by Ofgem and modifications made where required. For the business plan submission, the assurance of the restatement of historic data was managed via two additional processes:

- Where data requirement is simply to restate previously submitted data in exactly the same format but in a different price base, assurance processes were in place to ensure that data was correctly inflated and mapped.
- Where data was required in a different format or on a new basis, the revised data is subjected to the full data assurance activity as if for 2012-13 actuals.

In a small number of instances, this assurance identified minor issues with previously submitted data. Where such issues were found, we have restated the data.

4.2.2 Reporting of 2013-14 Data

The 2013-14 data is based upon actual data recorded up to the end of December 2013 and forecast data for the remaining three months. As such, there may be some differences between the 2013-14 data used in this business plan and the 2013-14 RRP. However, our assurance process and the utilisation of nine months' actual data will keep these differences to a minimum. As this is not a full year's data, we have not conducted a new risk assessment and have relied instead on the learning from the risk assessment conducted as part of the July 2013 business plan submission.

The assurance process for the reporting of actuals is already established under RRP governance and is compliant with Ofgem's data assurance guidance requirements. Although 2013-14 is not a full year of actual data, we have utilised many of the compliance processes that would be in place for the RRP to give confidence in this data including internal expert review of all data tables. The full data assurance process will be implemented for the full 2013-14 year as part of the RRP process.

Internal Assurance

The process for submission against the RIIO ED1 Business Plan Data Templates Regulatory Instructions and Guidance included review and approval by contributors from each directorate, table owners and internal expert reviewers. Key submissions are reviewed at our Board meeting and authority delegated to appropriate directors for detailed approval.

The following checking process is now utilised by individual table owners as they complete the tables:

- 'Level 1' – checks within one table that can be carried out by table owners as part of their sign off. Where appropriate these checks can be automated.
- 'Level 2' – checks between tables in the same pack that can be carried out on consolidation, with any issues flagged to table owners. Some of these can be automated, whereas others are wider 'sense checks'.
- 'Level 3' – checks between different reporting packs or regulatory submissions. These checks are less easily automated and require manual checks to ensure consistency.

4.2.3 Forecast

This section details the assurance approach for the completion of the forecast elements (the remaining one year and three months of DPCR5 and all eight years of RIIO-ED1) of our Business Plan Data Templates (BPDT).

Internal Assurance

Our approach to producing the business plan mirrors our approach for all of our large scale key regulatory deliverables. We have a table ownership document which sets out the responsibilities of table owners for the RRP and the BPDT for the WJBP submission. This document also sets out the business owner, support staff and an internal specialist reviewer for each table in the pack.

To ensure that our business plan is consistent with our day to day operation and reporting, the original business plan table owners were generally the accountable business area managers who report and review the annual regulatory reporting submissions to Ofgem. For this version of the business plan, the finance partners who support these managers have reviewed the forecasts to determine where changes are required and have then ensured that forecast and actual numbers are consistent.

The governance programme surrounding the submission ensured that senior management and the Board lead and understand the development of the business plan. The company established a RIIO steering group comprising senior managers from across the business attending. This group contained experienced regulatory specialists and professionals from across the business. This group developed the business plan positions and reviewed content for appropriateness. The ENWL Board has held a series of workshops with the senior management team to understand the content, progress, assurance and deliverables contained in the plan. These sessions have allowed the Board to sign off the business plan submission.

The business plan is based on our best view of future costs. Material assumptions used in compiling the numbers have been documented. These have been reviewed by the RIIO steering group and Board for appropriateness. These assumptions have been set out in the commentary for the business plan.

The quality assurance process for all data tables in our submission followed the process documented below:

- Individual table ownership established. This was based on a combination of business area and ongoing annual reporting responsibilities. Tables in the business plan which are not part of the regular reporting (eg Real Price Effects) were assigned based on business area responsibility. Tables are completed taking into account stakeholder feedback and business requirements. Table owners were also asked to complete the level 1, 2 and 3 checks described above as part of the table completion process.
- Completed tables were challenged and reviewed by a senior business manager and business area finance representative. The tables and commentary were signed off by all parties.
- High level adjustments, assumptions and consolidation of the tables into the submission were completed by a dedicated RIIO submission resource. Tables were reissued back to the table owners for confirmation.
- A review of the final tables was completed by Business Owner, Table Owner and Finance Support.
- Internal expert reviewers (named senior regulatory professionals) conducted reviews of the tables and provided feedback to table owners. Internal expert reviewers signed off the tables when they were satisfied that any issues identified were resolved.
- A summary view of all changes to the business plan since the July 2013 submission was presented to the Board for approval and sign off.
- The Board signed off the submission and approved the CEO to submit on its behalf.

External Assurance

The assurance process for forecasts is very different from the established processes for historic data or statements. For our July 2013 business plan submission, we worked with a number of external parties to develop, validate and challenge our assumptions in order to produce an appropriate, robust and efficient plan. We have checked that all of these reports remain valid and applicable where utilised to support this version of the business plan. The table below highlights the consultants/groups we worked with to develop the July 2013 business plan.

Company	Business area assessed
Mott MacDonald	Overall business costs
Gartner	IT costs
KPMG	Fixed cost assessment
KPMG	Cost of capital
PB Power	Activity volumes
EC Harris	Real Price Effects
CEPA	Regional economic forecasts
Smart Grid Forum	Low carbon investment projections and scenarios

Several of these consultants have provided annexes to the business plan and these documents were assured by the named individual company's processes.

For this version of the business plan we have commissioned additional reviews from the following external parties:

Company	Business area assessed
KPMG	Cost of capital
EC Harris	Real Price Effects
Oxera	Fixed costs
Oxera	Totex Efficiency
Oxera	Business Support Efficiency

4.3 Business plan narrative and commentary

The commentary and business plan publications have also been subjected to an assurance process. The key commentary was completed by the accountable managers as part of their table preparation process. This was signed off by a senior manager at the table sign off stage. Table commentaries were then reviewed by an appropriate internal expert reviewer.

The business plan publications have used the same core information but have been written to ensure that our customers and stakeholders can clearly understand the key elements of our plan and the implications for them. A separate exercise to check for consistency of numbers across all documents (and against the numbers in the tables) was completed.

Both of these publications have been assured by our internal expert reviewers and approved by as part of the WJBP approval process.

4.4 Plan On A Page

The plan on a page represents a customer friendly, high level factsheet summary of our business plan. There are several key elements which are included in the document. The assurance processes are described below.

- Key facts about our network – the data in this section is contained in the data tables. These numbers have been assured through our processes for the business plan tables.
- What we plan to do – this section is summarised from our outputs and deliverables section of our business plan submission. These documents have been reviewed via our internal challenge process.
- How will our plan be financed – the key cost of capital numbers and notional gearing percentages are average values for the eight years and are taken directly from the price control financial model input sheet.
- How much we propose to spend – all of the network expenditure and operating cost values are taken from the M1b and T1 Total Pensions tables. These have been assured through the wider business plan assurance process.
- How this will impact domestic customer bills – we have used the business plan outputs to populate a Common Distribution Charging Methodology model in order to provide price estimates for domestic customers. This model is governed by the prescribed industry rules. To ensure consistency of approach, our internal team who run the regular model updates have produced the RIIO-ED1 models and the same internal sign off process was followed.
- We have undertaken internal expert review of the population of Plan On A Page from the data tables.

4.5 Price Control Financial Model

The Price Control Financial Model (PCFM) has been developed by Ofgem from the RIIO-GD1/T1 financial models. The DNOs have reviewed the model's appropriateness for the electricity distribution price control.

The primary inputs to the PCFM are based on the summary tables in the business plan data pack. The assurance process for these tables is discussed in section 4.2. The input assumptions for the financial modelling (cost of equity, gearing, capitalised totex, allocation to tax pools etc) were based on financeability modelling, internal and external challenge. The final assumptions were approved and signed off by the Board.

4.6 Cost Benefit Analysis

Our cost benefit analysis (CBA) work was conducted by our network investment team using the methodology and models circulated by Ofgem. The analysis has been attached in the relevant sections of the business plan. The CBAs have been challenged by an internal expert reviewer and senior managers.

4.7 Investment Programme Approval and Scheme Paperwork

Investment projects are normally developed and approved in line with the governance arrangements outlined in our Internal Control Manual (ICM).

For the purposes of the submission, we have created supporting scheme papers some time in advance of the usual construction timescale. To facilitate this, we have adapted and expanded a form of our ‘Needs’ approval paperwork that would normally be presented relatively early in a scheme’s life requesting sanction to spend monies developing detailed solutions which would be presented for subsequent approval.

As these proposals have not gone through the ‘normal’ project approval process, they have been signed, reviewed and counter-signed by:

1) The scheme’s author
2) The scheme author’s manager, and
3) The senior manager responsible for that area of the programme.

In addition, all scheme papers have been reviewed and signed by a nominated Specialist Reviewer to check they are compliant with Ofgem’s requirements and consistent with the re-submission in all apsects (eg unit costs, Output projections, investment profling).

ANNEX 28: SMART METERING STRATEGY

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Contents

1. Executive summary

Smart Meters will be installed in the homes and businesses of our customers over the next few years. These devices will help our customers realise savings and benefits never before available. As our customers' usage of and reliance on electricity increases smart meters will become a vital part of the network management infrastructure.

This annex outlines how we will use smart meter data to improve our services and deliver savings to our customers. As the meter installation programme gathers pace our initial challenge will be to assist Suppliers in ensuring customers receive a safe and trouble free transition to the new meters. In parallel with this installation programme we will upgrade our IT systems to be able to use the meter data for the benefit of our customers. This IT upgrade programme has already started and to ensure we deliver benefits as soon as possible we have commenced several elements of this work in DPCR5. We are also working with suppliers to ensure customers are properly informed about both the installation programme and the benefits on offer.

We have worked through the various industry-led groups to ensure that the functionality of smart meters is suitable to assist Network Operators in meeting the challenge presented by the GB's de-carbonisation of heat, transport and electricity generation. This work will continue for some time and is vital to ensure GB customers receive the maximum possible benefits from their investment in this programme.

The installation programme will take five years to complete and once approximately 70% of meters are installed then customer benefits will start to be delivered. We have outlined below the main benefits to our customers and stakeholders arising from the adoption of smart meter data flows.

In total we forecast that customers will receive over £20 million of direct benefits across our RIIO-ED1 and RIIO-ED2 business plans. These benefits will be realised across the latter third of RIIO-ED1 and increase significantly in RIIO-ED2. To enable these benefits we will invest a total of £18.1 million, £3.1 million of which will be funded from our existing DPCR5 allowances.

2. Our smart metering strategy

The benefits of GB's adoption of smart meter technologies will mirror that seen in a number of countries and will accrue to the customers initially from Supply businesses and then later from Distribution Network Operators (DNOs). In the early years of the roll out programme, immediate benefits such as reduced meter reading costs and access to time of use based tariffs will be realised by customers. The customer benefits accruing from DNOs will be less immediate but eventually include:

- Improved network visibility and hence reduced or deferred network reinforcement costs
- Improved management of power outages
- Improved connection processes
- Reduced costs for micro generation customers
- Access to the benefits offered by demand side response
- Losses reduction
- Improved customer service across a range of routine activities.

Whilst the introduction of Smart Meters will bring immediate benefits to customers, their full potential in relation to network-related benefits will only be realised as customers increase their electrical power consumption or install generation. The profile of many benefits therefore follows the adoption pattern for Low Carbon Technologies (LCTs) such as Heat Pumps, Electric Vehicles and micro generation. In addition, in the early years of the smart meter roll out programme the penetration levels for smart meters will not initially facilitate a number of the benefits associated with network management.

Smart meter benefits encompass financial, service and less tangible areas and below we have outlined our thoughts on the main benefit areas. We believe that smart meters have a significant role to play in RIIO-ED1 serving as a platform for a variety of service and cost improvements. Critically, RIIO-ED1 will be the bedding-in period for smart meter technologies and their full integration into network operators' systems in preparation for wider scale LCT adoption and hence greater demand growth in RIIO-ED2.

2.1 How will smart meters improve network visibility?

Smart meters will for the first time allow us to monitor how much power our customers are using or producing in real time. This will allow us to not only influence their usage but to operate our network to be more responsive to their needs. The more responsive we can make our network, the more efficiently it operates and that helps us keep customers bills lower.

For many years we have had monitoring systems covering our extra high voltage (132kV and 33kV) networks enabling these systems to become steadily more efficient. At present we have virtually no visibility of our customers' needs on our low voltage (LV) network, and only limited visibility on our high voltage (HV – 11 & 6.6kV) network. The improved visibility provided through smart meter data will revolutionise network management allowing us to monitor demand across our entire network for the first time ever. This will help us ensure capacity is available for our customers to use when they need it and help us to ensure we only spend money increasing the capability of the network when absolutely necessary.

These benefits have been included in our investment plans and in our attached scenario submissions.

Customers are increasingly adopting micro distributed generation (DG) technologies such as photo-voltaic (PV) and micro-CHP; these generation technologies have huge benefits for both customers and the UK. However they also introduce a number of challenges for us. We have seen the rapid adoption of micro DG by tens of thousands of customers resulting in localised reverse power flows whenever generation output exceeds the demand. This can cause voltages to rise and we need to monitor voltages to ensure statutory limits are not exceeded. At the moment we do this by retro fitting various monitoring devices; smart meters will allow us access to this information at much lower cost. We will pass on these savings to our customers.

Smart meters will provide us with greatly improved visibility of voltage profiles along LV networks enabling better control of voltage and hence more efficient connection costs for all LCT equipment such as heat pumps. Our early work under our First Tier LCN Fund innovation projects clearly indicates that network visibility improvements enable lower connection costs using connect and manage technologies.

We have examined the use of smart meter data across the entire range of LCT penetrations included in the DECC decarbonisation scenarios. The benefits of smart meters allowing visibility of congested networks will be realised once meters reach approximately 70% penetration ie around 2019. We believe that the infrastructure detailed in our IT investment plans coupled with smart meter data will allow our business to respond efficiently to the needs of customers.

To ensure that we have included all likely smart meter benefits within our plans we led work undertaken by all DNOs through the ENA and commissioned KEMA, Redpoint and EATL to identify the potential benefits. These documents can be found as Annex 28 – A1 to A3. Their work mirrors our internal analyses and indicates that visibility benefits will manifest in two forms:

- a reduction in planning and design costs facilitated by improved visibility of network load and voltage levels and a reduced need to design reinforcement schemes based on the same visibility. These have been estimated at £0.38 million phased over the latter 3.5 years of RIIO-ED1. Prior to this date smart meters will not have penetrated sufficiently to allow the data to be used accurately

- In RIIO-ED2 under all DECC LCT scenarios the volume of connections rises and we would expect these benefits to exceed £2 million in the period

- A reduction in direct reinforcement costs arising from more accurate data, again this will occur in the latter half of RIIO-ED1. In our most likely scenario we have estimated the benefits of smart meters in the latter half of RIIO-ED1 at £1.1 million over and above the benefits of smart grid solutions. At higher penetration levels such as those shown in the DECC medium scenarios, benefits would increase slightly, however in the event of high penetration levels with dense clustering then smart meters offer proportionally diminishing benefits; as network loads go well beyond the existing network capacity.

The use of Smart Meter data in active network management techniques designed to reduce reinforcement costs are included in the Transform model and hence fully included in our business plan and all submitted scenarios. In our best view case based on the low scenario these benefits are relatively modest in RIIO-ED1 at £0.9 million but will increase significantly in RIIO-ED2 exceeding £3 million in the period.

2.2 How will smart meters improve our management of power outages?

Smart meters offer a number of important service benefits for customers experiencing power outages. Whist approximately 80% of customer interruptions are already detected automatically by our Operational IT systems, detecting the remaining 20% which arise due to LV network faults is dependent on customer calls. Smart meters offer significant functionality for the automatic notification of loss of supply for individual customers and we will incorporate these functions within our trouble management systems.

This will enable more rapid restoration of supplies particularly during storm events. Whilst SMETS1[1] compliant meters do not offer this functionality the proportion of SMETS2 compliant meters will be sufficient to allow outage detection on the vast majority of low voltage network events in the latter half of RIIO-ED1. The primary benefit for customers of early outage detection manifests in the form of a slightly earlier mobilisation of our operational response and hence earlier supply restoration. Our analysis of call patterns versus time of interruption indicates that this will result in an average 2.5 minute earlier detection and mobilisation. This will not result in an additional IIS reward as both the incident notification time and restoration time will be advanced by the same amount and hence all benefits will accrue to customers in slightly shorter outage duration times. This benefit will recur in all future RIIO periods; for RIIO-ED1 we estimate this benefit to be £0.3 million and for RIIO-ED2 £0.8 million based on the number of such event per annum, the number of customers per feeder and the RIIO-ED1 IIS incentive rate.

There will be a secondary benefit in terms of fault unit cost performance which arises through the more accurate diagnosis or the network section affected by open circuit LV cable faults. We have estimated this at £0.1 million over the last four years of RIIO-ED1; as high levels of smart meter penetration are required to enable this functionality. This will have an associated IIS benefit of a total of £0.64 million in the period arising from slightly faster localisation of such faults.

[1] DECC's Smart Metering Equipment Technical Specifications

Smart meters offer additional benefits for customers during storm events; as they enable more accurate diagnosis of LV network faults and hence better prioritisation of available repair resources and earlier supply restoration for some customers. These do not result in any reduction in repair costs as the same numbers of faults need to be repaired. Whilst more customers will benefit from earlier supply restoration, there is little appreciable IIS benefit as storm events are generally exempt from IIS. For non exempt events there is an IIS benefit to the DNO however this is outweighed by a larger disbenefit for DNOs as all faults are identified immediately as opposed to waiting for customers to contact a call centre agent to report no supply. We estimate the IIS equivalent benefit to customers in exempt storms will be approximately £1 million per annum post 2019.

We anticipate that smart meters will be of assistance in diagnosing LV network faults underlying HV faults post HV network repairs. Again this will allow some customers to be restored earlier leading to improved service at the macro level however similar to above there are no net reductions in repair costs or IIS benefits accruing to us. Use of last gasp functionality will be likely to evolve over RIIO-ED1 as penetration levels increase and communications and IT systems bed in. It is not possible to fully evaluate the financial benefits of this functionality until tested; however the benefits for customers are very apparent and we are committed to maximising all possible service benefits.

Whilst the so called ‘first breath’ and associated ‘pinging’ functionality has an important role to play in positive confirmation of supply restoration, our customers and particularly our vulnerable customers consistently tell us that they prefer a warm voice contact post supply restoration so as to enable them to understand the cause of the interruption and the likelihood of a repeat interruption. As such we do not propose to reduce the number of proactive voice contacts made and have not included any associated call centre savings in our plan.

Smart meters will enable us to automate the verification and identification of a number of standards such as the 12 hour restoration standard. This will not necessarily reduce the number of payments made as at the margins of the standard as many will be shown to fall inside as outside the set time. Processing of claims will be speeded up with customers benefiting from faster payments however given the relatively small number of projected events we do not forecast a material financial benefit to our current cost base.

2.3 How will smart meters improve our connection processes?

Improved network visibility as described above will also enable us to process connection applications more quickly and provide customers with greater certainty of efficient costs. Customers will benefit from a reduction in associated quotation and installation times. We have estimated the reduction in associated back office planning and design costs at £0.29 million for the RIIO-ED1 period and £0.8 million for RIIO-ED2. All direct cost benefits arising from smart meter data enabling more effective designs will accrue to customers in reduced connection costs. We estimate these to be in the order of £0.25 million in RIIO-ED1 and £1.1 million in RIIO-ED2. Note that LCT-driven costs for domestic customers are included in general reinforcement.

2.4 How will smart meters facilitate demand side response?

A significant potential benefit from Smart Meters arises from their potential to change customer demand patterns; either via a Time of Use Tariff signal or by use of the load switch. Our present understanding of both SMETS1 and SMETS2 is that we will not have direct access to either of these facilities.

In assessing the benefits associated with such behavioural change in customer profile classes 1–4 inclusive we have limited our modelling to examine the likely benefits to DNOs arising from similar signals sent by suppliers. In examining such potential alignment of price signal benefits we have considered the following points:

- Our work with Suppliers, National Grid and consultants such as Pöyry shows that price signals from Suppliers and the Transmission System Operator are likely to be dominated by hedging positions and real time balancing. Such markets signals span the entire load cycle; for example STOR[2], and do not necessarily align with peak network demand periods.

- Our customer engagement work on DSR generally and projects such as C_2C and CLASS shows that customers have a relatively low appetite for peak demand reduction DSR services unless offered a very strong price signal in the region of £20 000 per MWhr[3]. These findings are confirmed by other DNO projects. This payment level is adverse to the equivalent reinforcement NPV cost.

- Industrial & Commercial (I&C) customers have a greater appetite for so called "N-1 DSR" at much lower costs ranging between £14 000 and £24 000 / MWhr[4]. However this service cannot be used as effectively on secondary network feeders penetrated by LCTs as I&C customers are in the main fed by dedicated LV networks feeders or are connected at higher voltages.

- Our recent work with Baringa-Redpoint indicates that suppliers will put Time of Use (ToU) tariffs in place; however their effect is complex and not necessarily beneficial to DNOs. International trials show that peak price tariffs have little sustained effect on customer behaviour unless the price signal is extremely strong. Where a proportion of customers adopt sufficiently strong static ToU tariffs, then over the peak demand period 5 to 8pm their demand is reduced, but is increased at other times, most markedly between 4 to 5pm and 8 to 9pm. As a result the system peak may by moved outside of the 5 to 8pm window, although the reduction in system peak demand may be less that that observed in the domestic sector alone given higher demand from other sectors during the times that domestic load is shifted to, particularly 4 to 5 pm. This movement of domestic demand into the pre-system peak period may actually increase the net system peak. This effect is outlined fully in the attached Baringa-Redpoint report however the overall conclusion is that the effects of Supplier led ToU tariffs on peak demand is unlikely to be material before the early 2020s under all likely scenarios.

- Beyond RIIO-ED1 then automated appliance response coupled with ToU tariffs will allow more significant peak demand shaping reducing peak demand by up to 3GW nationally in 2025 and up to 7GW by 2031.

    - In our best view scenario LCT penetration levels are low and hence reinforcement costs are low and highly localised. The probability therefore of Suppliers sending a ToU signal that successfully or partially alleviates a reinforcement need is considered very low. Under the most optimistic viable ToU tariff scenario our work with Baringa-Redpoint indicates the effect on peak demand nationally to be 1000MW by 2025. This equates to less than 80MW against Electricity North West present peak demand of 4 500 MW. Given that this will be across our entire network and with the scarcity of LCT or other smart demand under the low scenario we are unable to identify an associated reinforcement expenditure reduction in RIIO-ED1.

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[2] STOR – Short term Operating Reserve etc...

[3] Early work on our C_2C project and on Low Carbon London indicates that domestic customers require a price signal of at least 10p / kWhr. This is borne out by our work with Baringa-Redpoint which shows that the value of ToU signals in RIIO-ED1 is likely to be low particularly under our best view low scenario.

[4] C_2C trials have indicated this is the viable price range for commercial scale DSR contracts.

- For micro DG the structure of FiT[5]s limits the effectiveness of generation side response to constrain output and hence reinforcement costs. These technologies respond more readily to smart grid solutions and the associated efficiencies are included in our reinforcement plans.

- We have examined in detail the potential affects of so called 'Wind Following' on market price fluctuations and peak demand levels. Our work with EATL and Baringa-Redpoint indicates that these are negligible in RIIO-ED1 but in RIIO-ED2 may exacerbate network constraints.

Given the above, our view is that ToU price signals issued by other market participants such as Suppliers will have limited, if any, benefit under low LCT penetration scenarios during RIIO-ED1. Further into the future as LCT volumes increase or under higher LCT penetration scenarios the effect of increased marginal plant costs are likely to produce stronger price signals and hence greater customer demand response. We have not therefore included additional smart meter benefits over and above those indicated by the Transform model in our most likely scenario.

Our innovation strategy requires us to continue to explore new ways of engaging with customers to mitigate the effect LCTs on the network. We are at the forefront of change and development in this area; for example the development of new local energy market services such as C_2C, the use of third party services such as aggregators, social landlords or communities of customers to effectively purchase distributed resource services to deliver network benefits. These new services have the potential to marginally reduce costs under our most likely scenario but have much greater potential to reduce costs under higher LCTs scenarios.

We have worked with Ofgem on the development of suitable uncertainty mechanisms to ensure the benefits of such work are appropriately shared between customers and other stakeholders. We believe that the structure of efficiency incentives and re-openers outlined in the RIIO-ED1 strategy decision provides a strong incentive to continue to develop and realise such DSR benefits.

Critically, our submission is based on a number of benefit assumptions contained within the Transform model, specifically the forecast cost of services such as DSR, storage and other new technologies. In the event that costs or other assumptions vary then the associated benefits may change and hence trigger the load re-opener.

2.5 How will smart meters aid losses reduction?

It is inevitable that as energy flows increase network losses will increase, however the effects of smart meters on peak energy demand may assist DNOs in helping to curtail this rise. In particular improved network visibility will allow us to progressively improve the management of feeder voltage profiles and hence losses management.

Our work with EATL indicates that smart meters will cause customers to become significantly more aware of their energy usage. This will have a forecast benefit on losses driven by price visibility, energy usage visibility and energy awareness. At GB level EATL forecast this to be in the region of £35 to £45 million over the period 2015 to 2031. This equates to £3.1 million for our region occurring predominantly in RIIO-ED2 and will accrue directly to Electricity North West's customers.

[5] Feed-in-Tariff.

2.6 How will smart meters improve dataflow management?

The introduction of smart meters will allow some simplification of our billing and dataflow management processes. However these will only be realised towards the end of the installation programme; in RIIO-ED2 we expect these to total £0.8 million.

2.7 Other customer service benefits

Our customers and other stakeholders consistently rank CIs, CMLs and price as their top priorities. Our engagement also shows that they also place value on other factors such as the speed of response and information provision across a range of requests. Smart meter functionality enables a number of features including real time polling:

Meter messaging

We do not consider the messaging functionality available to DNOs to be sufficiently developed in SMETS2 to allow services such as Planned Supply Interruption notifications to be effectively migrated to smart meters. We do however foresee potential to provide supplementary updates of value to customers on forthcoming Planned Supply Interruptions such as timings and other information such as severe weather warnings. We have included the associated data costs within our submission however these are only minor transaction charges. The benefits arising from this improved information flow will benefit customers however we do not believe they will be material as observed in mechanisms such as the customer satisfaction incentive.

Voltage enquires

We receive a small number of routine enquiries from customer regarding their supply voltage. At present we fit monitoring equipment to the customer's installation to check if their voltage is within statutory limits. Smart meters will provide an almost instant means by which we can check the customers supply voltage and hence reduce our measurement costs. We estimate these savings to be £0.1 million in RIIO-ED1 and £0.4 million in RIIO-ED2 and these have been included in our business plan.

Guaranteed standards

Smart meters will enable us to proactively check and verify if customers are entitled to a guaranteed standards payment. This will improve the efficiency of our back office processes and importantly ensure customers receive any payments due promptly. We estimate these savings to be £0.1 million in RIIO-ED1 and £0.34 million in RIIO-ED2 and these have been included in our business plan.

As the functionality of smart meters and the surrounding IT infrastructure evolves we will continue to develop new services and benefits to customers based on this valuable data source. The greatest value from smart meters will arise once demand levels increase significantly on our network which we forecast will occur in RIIO-ED2 and RIIO-ED3.

3. Customers' smart meter benefits

3.1 – Customer benefits for our best view scenario

In Table 1 below we have summarised both the financial benefits for customers included within our plan and those they will receive external to our plan.

Table 1: Smart meter benefits summary

Benefit area	RIIO-ED1 period value £m	RIIO-ED2 period value £m	Savings included in RIIO-ED1 WJBP
Network visibility	£0.9	£3.0	Yes
Power outage management	£0.74	£1.5	Yes
Connections	£0.29	£0.8	Yes
Planning and design costs	£0.38	£0.9	Yes
Dataflow management	-	£0.8	Yes
Voltage investigations	£0.1	£0.4	Yes
Guaranteed standards	£0.1	£0.34	Yes
Benefits within plan	**£2.51**	**£7.74**	
Additional benefits realised by customers external to Electricity North West's business plan			
Reduced power outage duration	£0.3	£0.8	No
Reduction in network losses*	£0.2	£3.1	No
Storm benefits	£2	£8	No
Reduced connection costs	£0.25	£1.1	No
Additional benefits	**£2.75**	**£13.0**	
Total benefits	**£5.26**	**£20.74**	

3.2 Savings arising under alternate LCT adoption scenarios

The above savings are based on the DECC low LCT adoption scenarios. Savings under higher adoption scenarios are likely to be much larger.

In particular, the forecast reduction in losses is the minimum value likely to be observed, however under higher LCT growth scenarios coupled with the introduction of active time of use tariffs by Suppliers, then this benefit could rise to as much as £9M pa by RIIO-ED2, equating to over £72M of additional benefits for customers over the RIIO-ED2 period.

In addition to losses savings, time of use tariffs under the high scenario would be likely to add a further £4.8M of reinforcement savings pa by 2025 totalling an additional £29M by the end of the RIIO-ED2 period.

4. IT system changes

4.1 Scope

New IT systems and integration with existing IT systems will be required to support the roll out of smart metering within Electricity North West. The IT system changes that will be delivered within the remainder of the DPCR5 period and throughout the ED1 period to support the roll out smart meters to customer premises include; interfaces to DCC, integration into our network management (NMS), customer response management (CRM) and registration services.

The key objectives during the RIIO-ED1 period are:

- Support the Supplier smart meter rollout via the introduction of new scheduling and appointment tools (to be implemented in DPCR5)
- Connect to DCC systems to enable smart meter interaction (Alerts and Services)
- Improve network visibility to reduce or defer network reinforcement costs
- Improve customer service across a range of routine activities
- Provide the foundation for the future Smart Grid

4.2 Business Change drivers

The adoption of smart metering will require us to undertake a number of mandatory activities. In addition there are several non mandatory data transactions offered by the DCC which the business will adopt driven by the business benefits as outlined in this annex:

Smart meter rollout - DNO interventions

- The network operator is obliged to inspect and potentially undertake remedial works where a meter operator advises they are unable to complete a smart meter installation at a premise due to safety or other issues affecting the service termination. It is likely that many such referrals will come through industry data flows however it is also likely that our contact centre will experience an increase in customer or meter operator calls relating to smart meter installations. In order to ensure that we are able to offer excellent service to customers, whatever the communication route, we will implement enhanced work scheduling systems within DPCR5.

Industry interfaces – business systems changes mandated by licence condition:

- Registrations interface changes
  - Changes to existing interfaces to accommodate unique property reference number (UPRN) and SMETS data items
  - New interfaces from the DCC to inform us of the enrolment of each smart meter and to the DCC to update supplier registrations and agent appointments.

Further changes may also be mandated at a future date, potentially including:

- Additional registration and billing interface changes deemed required by DECC to support the smart meter roll out
- Billing methodology changes. Small/medium commercial sites may in future be billed from half hour consumption data obtained from smart meters. Billing of domestic properties is currently based upon aggregated profiled consumption, it is not currently envisaged that this would change
- Centralised registrations. It has been suggested that meter point registration systems may be centralised within DCC at a future date to be advised
- Requirements to certify the organization (or parts thereof) to standards such as ISO27001
- Costs for delivering future mandated changes such as described above are not included within the plan and any costs incurred as a result of additional mandated

requirements or change would be expected to be treated as pass through if they occurred – ie additional to this plan

Network operator participation and use of smart meter data is not currently mandated by DECC or Ofgem. We believe however that smart meter technology offers benefits for customers and therefore intends to be early adopters. For this reason, an investment of £1.5m has been brought forward from RIIO-ED1 to DPCR5 for DCC integration enabling Electricity North West to fully align with DECC and industry expectations that DNOs will actively invest and participate in smart meter readiness activities during the DPCR5 period.

Interaction with the DCC will be required in order to access smart meter data:

- Communications
    - Interface specifications are defined by the DCC; network operators will need to comply with interfaces specifications and communication protocols in order to access smart meter data.
- Privacy and security
    - Access to smart meter data will be subject to strict privacy and security requirements - to be defined within the smart energy code (SEC). Network operators will be required to achieve certification against the SEC obligations before being able to access smart meter data
    - Formal security risk assessments will be carried out on an annual basis, and an independent third party will undertake an audit of information security management.

Access to smart meter data services will enable customer and business benefits as outlined in our smart meter strategy. Examples of smart meter data flows that support the identified benefits include:

Improved network planning

- Read profile consumption data
- Read network data (voltage and power quality logs)
- Read maximum demand registers

Improved network management

- Manage device (configure event alert thresholds)
- Read network data (voltage and power quality logs)
- Read maximum demand registers

Improved outage management

- Last gasp/first breath alerts
- Read supply status

Improved customer service

- Read supply status
- Read network data (voltage and power quality logs)

Some services will bring immediate benefits eg the ability to remotely interrogate a smart meter device and determine supply status without the need to despatch a fault technician. Other benefits will only be realised in the longer term when sufficient volume of smart meter data becomes available eg detailed consumption data assisting in long term network planning.

Network Management System solution vendors are expected to significantly upgrade their product offerings in order to fully exploit the capabilities and benefits of smart meter data and for this reason the expected procurement of a new Network Management System has been partially deferred in order to ensure that we obtain the best fit of functionality and integration of smart meter data, as a result £1.5m of NMS smart metering development costs have been pushed back into the RIIO-ED1 period from DPCR5. Note that in cash terms this move when considered with our advancement of DCC interface, as noted above, nets to zero.

4.3 IT system landscape

To have access to smart meter data we will require a new communications interface to the DCC. We are working closely with other DNOs to help understand and define the requirements of such a system and to ensure comprehensive review, and where appropriate challenge and feedback to DCC interface design drafts. It is intended that we may partner with one or more interested network operators to specify and procure the necessary IT systems for the interface, sharing costs equitably and hence delivering benefits at the lowest possible cost to customers. It should be noted that some potential solution vendors have given prior indication that they may seek to licence DCC communications software and services to the corporate entity rather than to individual distribution licence holders, in such case our total IT costs will be proportionately higher and may not compare favourably with a direct comparison of other DNOs who are able to leverage a single solution purchase to service their multiple distribution entities.

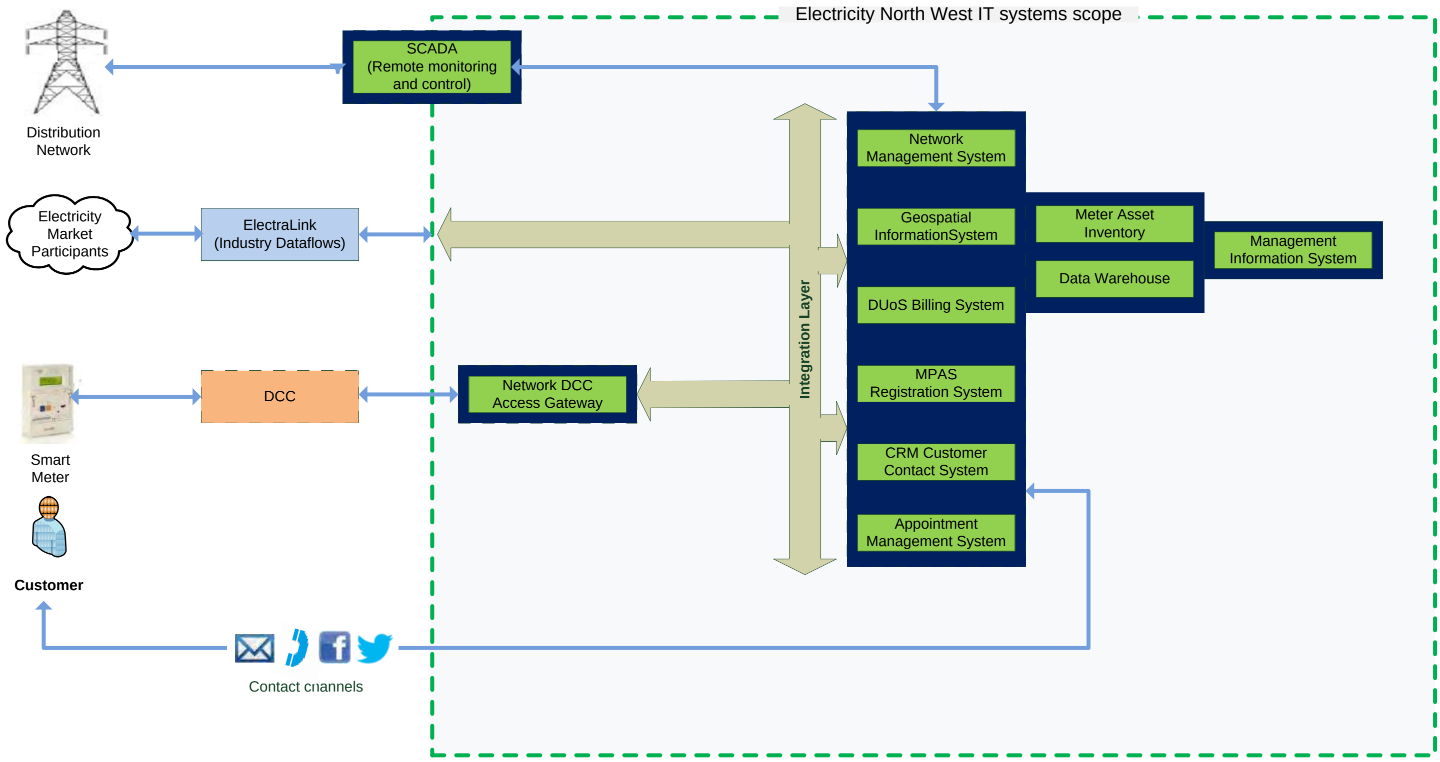
Connection to the DCC will require us to meet a defined set of security criteria affecting systems, process and staff resource. Our investment plan accounts for achieving and maintaining ISO27001 compliance which we believe fulfils the information security and privacy requirements currently required by SEC for our DCC User Systems. In the event that SEC changes mandate ISO27001 certification any costs arising will be additional to our plan and we have assumed these costs will be allowed as efficient smart meter related implementation costs under the uncertainty mechanism. Further work will be required to then integrate the use of smart meter data into our systems and processes to realise the forecast benefits.

Changes to industry data flow interfaces will be mandated to support the exchange of smart meter data between other industry parties and data and licence charges will be mandated for the use of smart meter data.

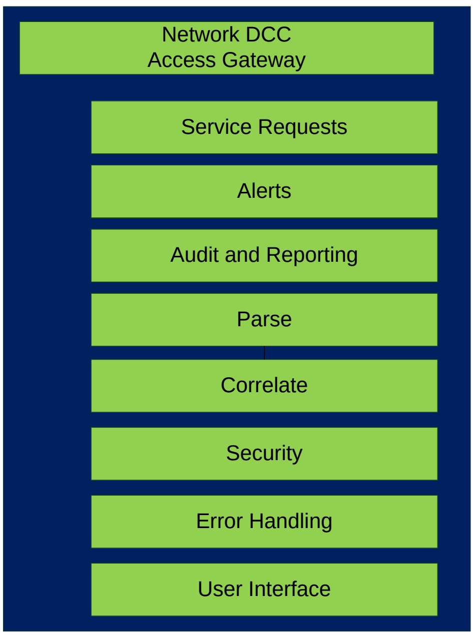
With the introduction of smart meter data there will be a requirement for secure storage and access control of sensitive data (consumption profile data) and data integration with the network management system to aid fault diagnosis and future network planning.

From mid to late 2015 the supplier rollout of smart meters is forecast to ramp up significantly. At the peak we will expect 8,500 meters installed per week across the region, with an anticipated rate of between 2 - 5% of installations requiring network operator intervention to support the installation process. This represents a 400% increase on normal installation volumes and will require a corresponding ramp up of engineering resource. New and amended IT systems will be required to help manage and support the increase in workload in resource scheduling and customer appointments management.

Conceptual Systems schematic



Network DCC Access Gateway

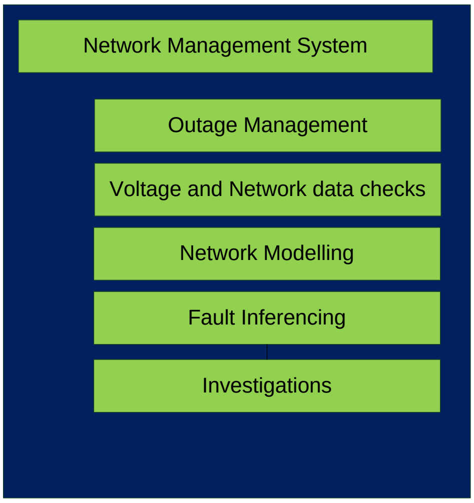


Smart meters deliver the capability to be remotely interrogated and collect engineering and consumption data. Access to smart meter data can only be achieved via the DCC, direct meter access is not permitted. A new IT solution is required which will handle the communication, security, audit and control of all data exchanged. The gateway will provide both machine to machine interfaces and a user interface to allow the full range of network operator smart meter commands to be utilised.

Minimal business logic will be embedded within the gateway although some common responses and orchestrated activities may be specified as a part of the common requirements definition taking place in partnerships with the other DNOs eg automatic change of meter security keys and configuration of network parameters whenever a new smart meter is installed.

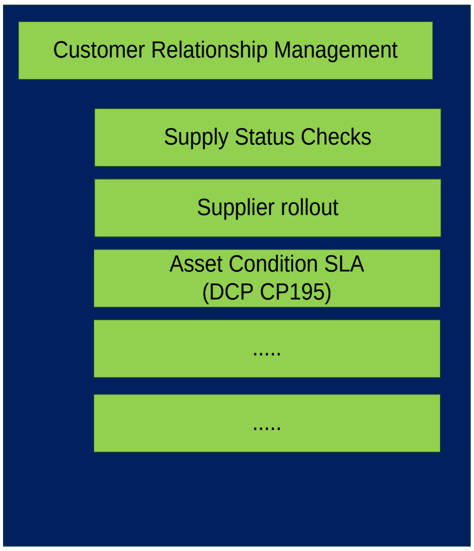
The gateway is expected to maintain the inventory of smart meter device ID to MPAN mappings but will not store any transactional smart meter data, acting only as the interface to Electricity North West's back end systems.

Network Management System (NMS)



Separate to the introduction of smart meters, we are replacing our existing NMS with an up-to-date system that will provide smart grid functionality. The new NMS will use smart meter data to fulfil its potential, including loading data and alerts from smart meters. Given the emerging nature of smart grids, it is expected that the interface requirements between the DCC Access Gateway and the NMS will continue to develop.

Customer Relationship Management (CRM)



Separately to the introduction of smart meters, we are introducing a new Customer Relationship Management (CRM) system with the aim of centralising and improving all the interactions with customers.

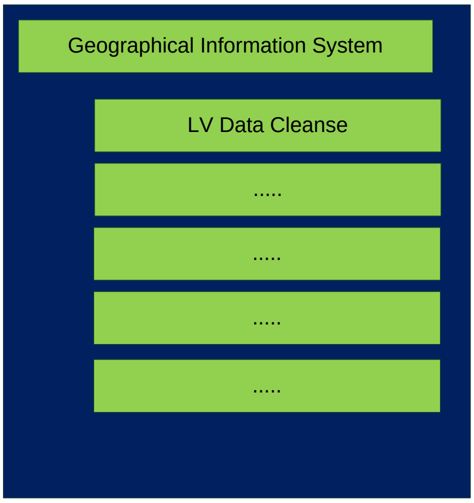
The CRM will be integrated with the DCC Access Gateway and NMS systems so that call agents can provide the customers with more accurate information regarding the scope, nature and expected resolution timescales for any incidents, including those related to metering issues.

The CRM system will be enhanced to support all aspects of the smart meter rollout, including introduction of Asset Condition SLAs (DCP CP195).

Appointments Management System

During the smart meter rollout, the meter operator may identify problems at the service position and where the network operator will be required to undertake work before the smart meter can be installed, eg replacement of the cut-out fuse assembly. Electricity North West needs to enhance its appointments management system to manage the expected volumes of interventions triggered by the smart meter rollout. We intend to use the appointments system to schedule both direct and contract labour. The appointments system will interface to the CRM to provide a seamless service for customers.

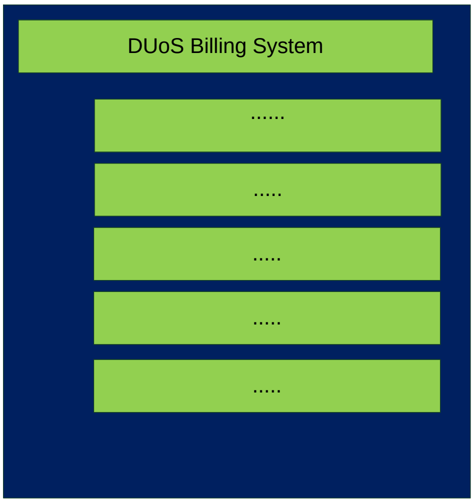
Geographical Information System (GiS)



The introduction of smart meters should not directly affect the GIS system; however to make any realistic use of available smart meter data it will be critical to modify GIS system data to make accurate the LV network connectivity model. For example without a completely accurate connectivity model, last gasp alerts for fault inferencing will not work efficiently. A comprehensive programme of LV data cleansing work is required to map meter assets to LV service terminations

We have included £4m investment to undertake this LV data cleanse activity.

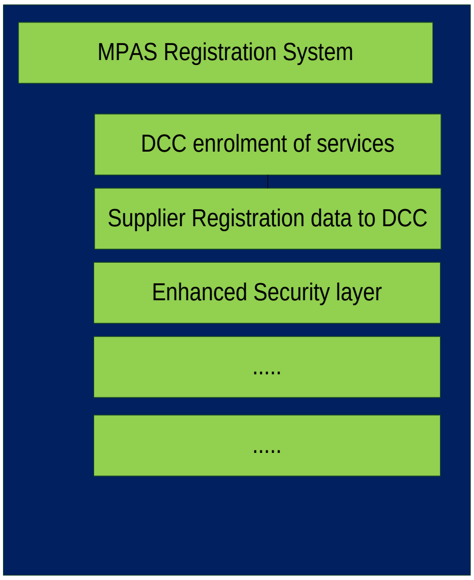
DUoS Billing System



There is unlikely to be any significant changes to the DUoS billing system during the early part of RIIO-ED1 but as smart meters become more prevalent the industry may develop new tariffs and charging initiatives which, for example, need to send appropriate Demand Side Response cost signals to consumers.

Although these could require billing system changes, we have not included any significant costs within plan.

MPAS Registration System

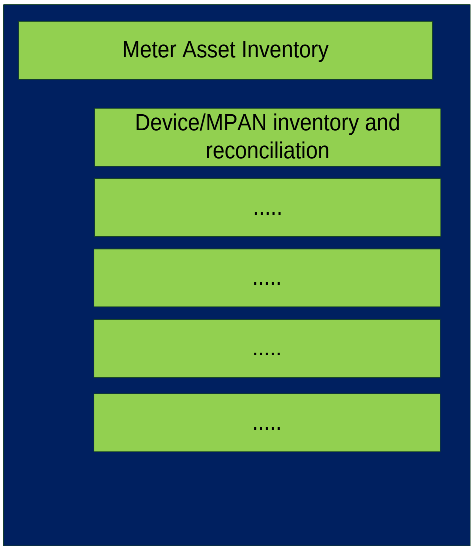


DECC have mandated changes to existing registration interfaces to cater for the exchange of new smart meter data attributes and also defined new interfaces to enable exchange of registration data with the DCC. We will have to change to our existing systems to meet the security requirements for the DCC and in line with DECC timescales.

From circa 2017 there is also the likelihood that Registration systems will be centralised within the DCC. This will require the development of existing, or new, interfaces for billing and other purposes.

We have not included any costs for centralisation of the DCC registrations system, assuming that we would be able to achieve it within the existing DCC interface capabilities rather than require any new infrastructure.

Meter Asset Inventory



The introduction of smart meters introduces new data attributes into several different business areas. To manage the relationship between smart meter devices, MPANs and notifications of DCC enrolled MPANs in registration systems a new meter asset inventory system is required.

We note that Ofgem has begun the process of consulting with industry on the potential creation of a centralised meter asset database. Centralisation will require the development of existing or new interfaces for billing and other purposes.

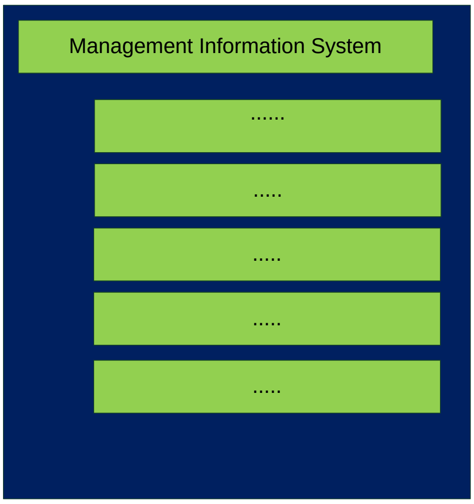
We have not included any costs for any significant integration to a centralised DCC asset inventory system. We assume that we will be able to achieve this within the existing DCC interface capabilities rather than require any new infrastructure.

Data Warehouse

Smart meter data will allow more detailed and accurate modelling of gross customer demand which will improve our network planning and help reduce or defer network investment. There are significant security implications in using customer data in this way, and we will have to implement appropriate data security systems including aggregation

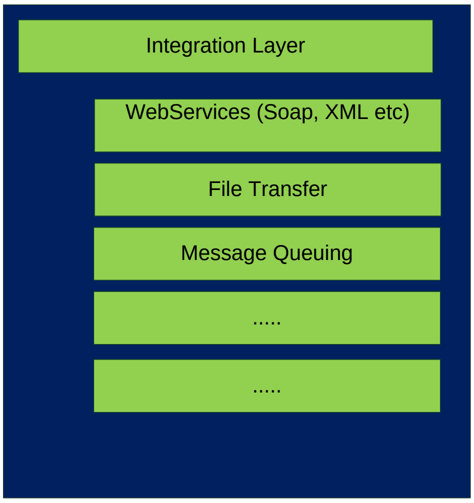
Large volumes of smart meter data may be collected from smart meters, a typical consumption profile data read from a 90 day period may contain up to 18 000 data points for one customer. We will introduce a new secure data warehouse which will maintain and control access, security and auditing of the use of data consistent with the requirements of Ofgem, DECC, and the Information Commissioner's Office.

Management Information System



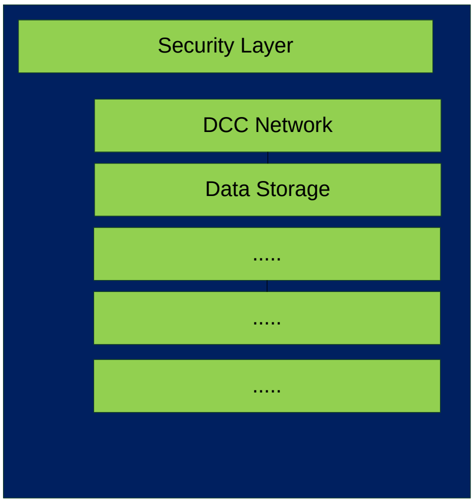
Smart meter data will allow more detailed and accurate modelling of aggregated customer demand which will improve our network planning and help reduce or defer network investment. New management information will be developed to help control, simplify and enhance network management, analysis and reporting.

Integration Layer



The integration layer will provide for the technical integration middleware and infrastructure required to join the various system components together. At present no one specific integration product or platform has been defined, it is expected that the layer will comprise of one or more of the technologies listed to the left. There may be different levels of integration applicable at different phases of the smart meter rollout as the volumes of smart meters installed grows and the resultant business benefits become more valuable.

Security Layer



Additional security compliance and audit requirements apply to connecting to the DCC network and also to storing smart meter data (disaggregated consumption profile data). Provision has been made for complying with relevant aspects of ISO27001 and the Data Protection Act.

Attaining actual ISO27001 certification or achieving compliance for wider system and process requirements are not currently included in the plan.

4.4 Costs

Smart Meter rollout

The following table indicates the ongoing Indirect/IT and data services costs with regards to smart meter rollout:

	DPCR5	ED1 Pass through period	2022	2023
IT set up costs for scheduling and appointments management (during DPCR5)	0.5			
Registrations and additional scheduling and call centre resource (during rollout FY16-FY21)		1.2		
Total	**0.5**	**1.2**		

Smart meter data and DCC integration

The following table indicates the ongoing data services costs with regards to smart meter data and DCC integration:

	DPCR5	ED1 Pass through period	2022	2023
DCC Licence Fee through ED1 (assumed costs)		2.4	0.4	0.4
Smart meter transaction data charges through ED1 (assumed costs)		0.6	0.1	0.1
Total		**3**		

The following table indicates the ongoing Indirect/IT vices costs with regards to smart meter data and DCC integration:

	DPCR5	ED1 Pass through period	2022	2023
Network DCC Access Gateway	1.5	1.2		
Integration and Analytics	0	3.0		
Asset Inventory	0	0.5		
Data Storage	0	0.5		
Data Centre/Hardware	1.0	0		
NMS (enhancements enabling utilisation of smart meter data)	0.5	2.3		
LV Data Cleanse	0	4		
Project Management, business support, Infrastructure support and maintenance	0	1.5	0.5	0.5
Hardware/software refresh	0	0	0.5	0.5
Security	0.1	0		
Total	**3.1**	**13.0**	**1.0**	**1.0**

4.5 Benefits

The aforementioned IT system changes are required in order to deliver the benefits as defined in this annex.

Smart Metering Load Shift Analysis

A report for the Energy Networks Association

Version: 1.1 **Date:** 19/06/13

Version History

Version	Date	Description	Prepared by	Approved by
1.0	15/05/2013	Draft	Florence Carlot Luke Humphry	Duncan Sinclair
1.1	19/06/2013	Final report	Florence Carlot Luke Humphry	Duncan Sinclair

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Contents

1 Executive Summary

1.1 Context

The UK Government has mandated the roll-out of smart meters to all Domestic and Small and Medium sized Enterprise customers by 2020. A significant proportion of the benefits identified in the business case for this decision came from savings associated with demand reduction and shifting associated with Time of Use (ToU) tariffs, reducing the requirements for peak generation and network infrastructure and associated electrical losses.

In March 2013, The Energy Networks Association (ENA) published analysis showing £1.6 bn of potential network related benefits from smart metering over the RIIO-ED1 (2015-2023) and ED2 (2023-2031) periods. Components providing the largest benefits are the avoided, deferred or reduced reinforcement costs related to ToU tariffs and Direct Load Control (DLC) and reduced network losses also resulting from load reduction and shifting. However, those benefits are heavily dependent on supplier-led implementation of ToU tariffs, and consumers' response to them, and - the data security architecture for the Data and Communications Company (DCC) means that there are restrictions on the load control actions that the DNOs can take directly and the final Smart Metering Equipment Technical Specifications version 2 (SMETS2) specification means that the DNOs will not be able to deliver some of the benefits identified by the March 2013 analysis.

1.2 Project Objectives

In the context of this dependency on supplier-led initiatives, ENA asked Baringa Partners to provide an analysis of the likely amount of demand reduction and shifting at the time of network peak that might actually be achieved from Domestic and Small and Medium Enterprise (SME) customers over the RIIO-ED1 and ED2 periods. This involved modelling the demand profile projections until 2031 (including assumptions on the uptake of Low Carbon Technologies) and evaluating the penetration rate of ToU tariffs over time and the customer response to those supplier offerings.

1.3 Assumptions

We modelled scenarios covering a range of electricity demand assumptions based on the uptake of Low Carbon Technologies (LCTs), namely heat pumps, electric vehicles and smart appliances, and the rate of uptake of ToU tariffs by customers.

The following ToU tariff types were considered:

- Static Time of Use (SToU) - different rates depending on the time of day, fixed at any point of time
- Critical Peak Pricing (CPP) – a dynamic tariff which gives suppliers the right to exercise a limited number of high priced events during pre-specified time periods
- Direct Load Control (DLC) – a dynamic tariff whereby suppliers/customers are able to control loads automatically according to market prices

In addition to a Business As Usual (BAU) case with no uptake of ToU tariffs, we modelled three alternative ToU cases:

- ToU1 – In this case, we assume a proportion of customers move from unrestricted tariffs to SToU tariffs

- ToU2 – In this case, we assume a proportion of customers move from unrestricted tariffs to both SToU and DLC tariffs
- ToU3 - In this case, we assume a proportion of customers move from unrestricted tariffs to both SToU and CPP tariffs

For each ToU case, we modelled three different scenarios of demand flexibility:

- Low
- Central
- High

Flexibility is created by the penetration of controllable LCTs, and by consumers responding to price signals created through ToU tariffs. The Low, Central and High flexibility scenarios refer both to the penetration of LCTs and the level of uptake of ToU tariffs by consumers. As an example, the uptake of LCTs in the High flexibility scenario would imply higher peak electricity demand, should no load shifting occur primarily as the result of heat pumps which add peak heating load to the traditional peak electricity load. However, much LCT demand has the potential to be flexible, through storage and smart systems, and so where consumers are incentivised to utilise this flexibility, load may be shifted and so the peak demand reduced. Hence, the change in peak demand in the High flexibility scenario compared with the Business As Usual case is a function of higher LCT demand (pushing peak load up), but with higher responsive of consumers through greater uptake of ToU tariffs (shifting load and bringing the peak down).

For our assumptions on consumer response to ToU tariffs we have drawn heavily on domestic and international trial results such as the on-going Customer Led Network Revolution (CLNR) trial in the UK and the Irish trial performed by the Commission for Energy Regulation (CER). Assumptions on future demand, uptake of heat pumps and electric vehicles, underlying capacity mix, future fossil fuel and carbon prices are sourced to the extent possible from analysis published by DECC through the smart metering and Electricity Market Reform (EMR) programmes, and supplemented with our own assumptions.

The modelling results provide a view of the impact of the potential Domestic and SME peak demand shifting on the overall peak demand (at the system level) through a combination of ToU tariffs. The uptake of ToU tariffs, enabled through the roll-out of smart metering, is assumed to increase over time with the initial focus on Static ToU and CPP tariffs. In the 2020s, through enabling technologies and enhancements in the sophistication of settlement systems, DLC tariffs are assumed to become more prevalent.

Based on evidence from the trials, we have assumed a 2% reduction in consumption from domestic customers on ToU tariffs prior to any demand shifting, associated with greater awareness of electricity consumption. No demand reduction was assumed for the SME sector, since there was little evidence from the trials to suggest reduction in usage from customers on ToU tariffs.

1.4 Results

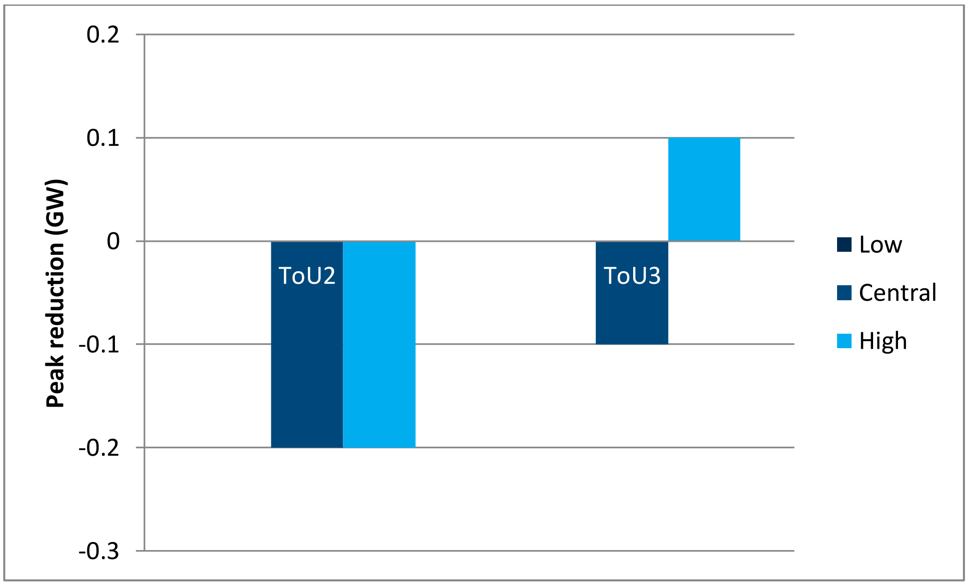
In all cases modelled (except the BAU case), there is a proportion of customers on SToU tariffs. Over the peak demand period 5-8pm their demand is reduced, but is increased at other times, most markedly between 4-5pm and 8-9pm. As a result, the system peak may by moved outside of the 5-8pm window, although the reduction in system peak demand may be less than that observed in the Domestic sector alone given higher demand from other sectors during the times that domestic load is shifted to, particularly 4-5 p.m. In the ToU2 and ToU3 cases there are customers on dynamic CPP and DLC tariffs, who respond to live price signals. The amount of load shifting is dependent on system conditions, which become increasingly influenced by the output from intermittent renewables as the generation mix shifts to more low carbon generation.

The figures below show the potential peak demand reduction, relating to permanent demand reduction and demand shifting, at the system level first, and then the results of the impact of the ToU tariff cases on Domestic and SME sectors separately. The results are shown for 2020, 2025 and 2031.

System Level

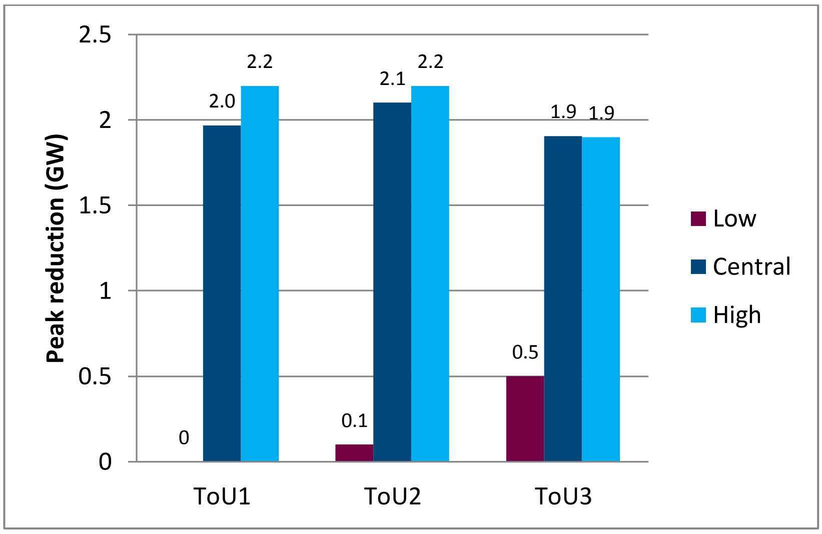
The impact of ToU tariffs on the peak demand becomes material by 2025 and significant by 2031. As illustrated in Figure 1 below, there is limited, or even slightly negative, impact on system peak demand under the three ToU cases in 2020. This is mainly because the assumed uptake rates are low by this date, and what shifting that does occur simply moves the peak rather than materially reducing it.

Figure 1 – Reduction in peak relative to Business As Usual by Time of Use case (2020)



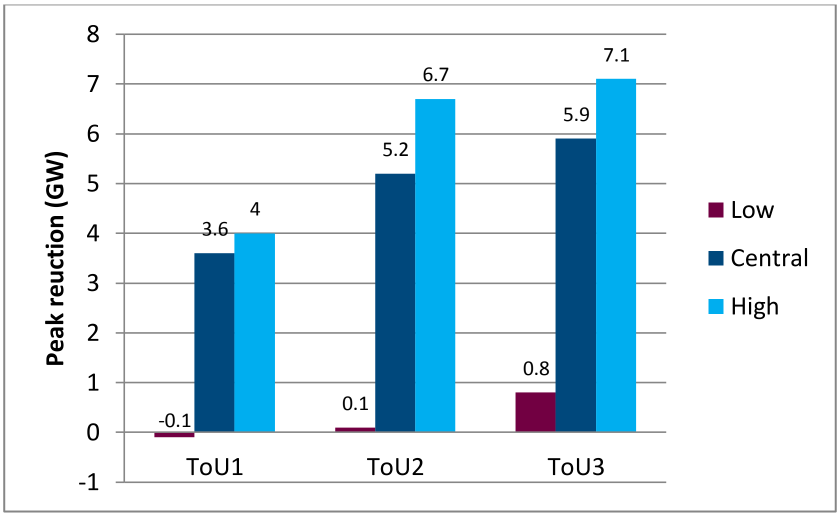
As illustrated in Figure 2, by 2025, the impact of ToU tariffs on system peak demand could be as much as a 2 GW reduction. The ToU1 case provides the lowest peak demand reduction, with no peak reduction in the Low flexibility scenario. The biggest peak demand reduction of up to 2.2 GW occurs in the ToU2 and ToU3 cases. This would represent a reduction in peak demand of approximately 3%.

Figure 2 - Reduction in peak relative to Business As Usual by Time of Use case (2025)



By 2031, the greatest amount of peak demand reduction occurs in the ToU3 case, given the value of direct load control in helping to manage the system with high penetrations of intermittent renewables. In the High flexibility scenario this reaches 7.1 GW or approximately 8% of peak demand.

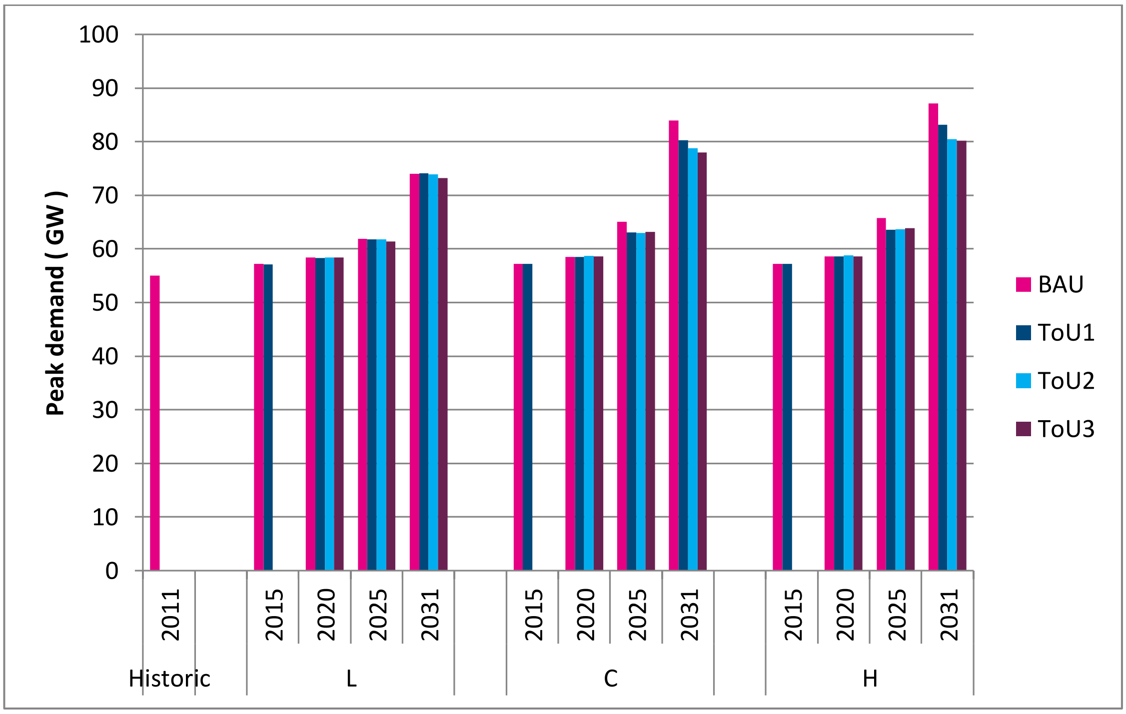
Figure 3 - Reduction in peak relative to Business As Usual by Time of Use case (2031)



It is useful to set in context the potential reductions in peak demand associated with ToU tariffs against the increases in peak demand expected, not least since it is the LCTs which provide much of the flexibility that are contributing most to increasing demand in the future.

Figure 4 shows peak demand under BAU and each ToU case for the three different flexibility scenarios over the ED1 and ED2 periods and compares this to historic 2011 peak demand. This shows that the additional peak shifting associated with the higher flexibility cases is not sufficient to offset the increasing underlying demand, but that ToU tariffs are important in mitigating the increase.

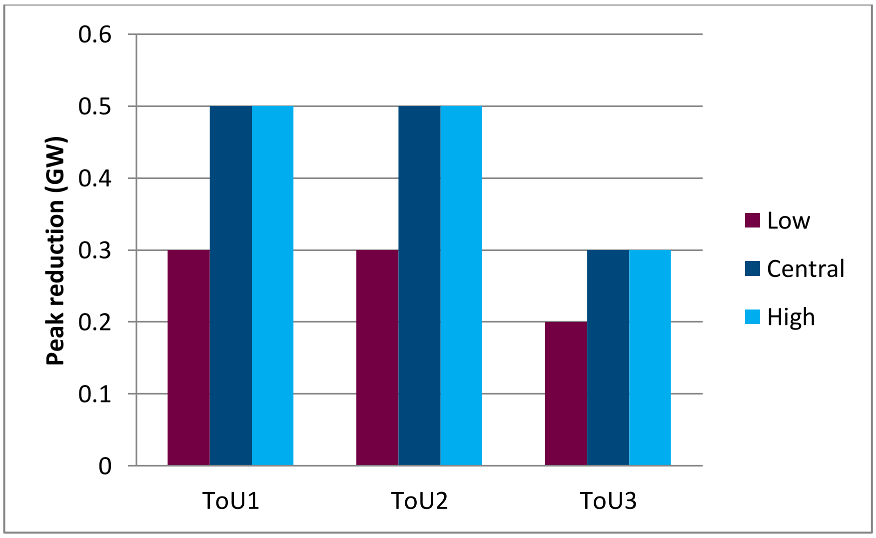
Figure 4 - Evolution of peak system demand and peak savings by ToU case and flexibility scenario



Domestic Level

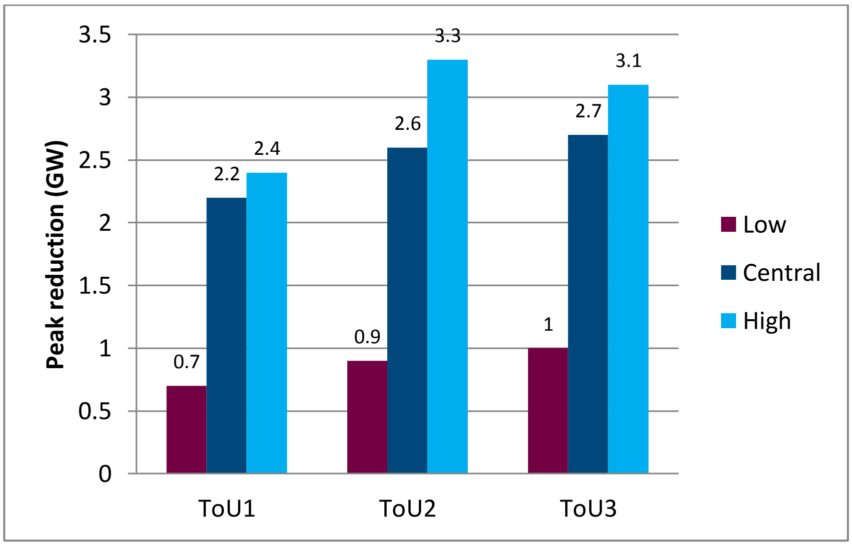
Limited domestic peak demand reduction associated with ToU tariffs is expected to occur in 2015 and we notice limited peak demand reduction in 2020. This can be explained by the low uptake assumptions of LCTs and ToU tariffs and low responsiveness assumptions of consumers.

Figure 5 - Reduction in peak relative to Business As Usual by Time of Use case (2020)



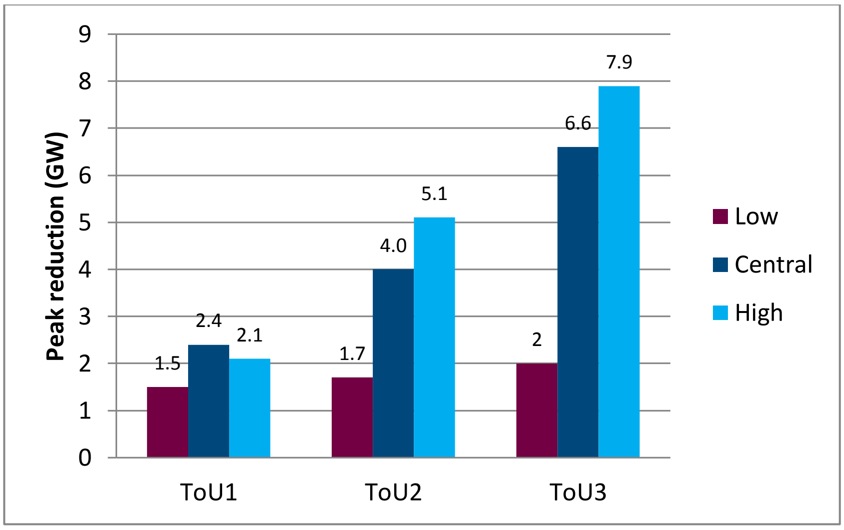
By 2025 the impact is more significant. For example, under the ToU2 case and High flexibility scenario peak demand reduction is 3.3 GW or 12% of peak domestic demand (27.8 GW). The lowest outcome is 0.7 GW which occurs under the ToU1 case and Low flexibility scenario.

Figure 6 - Reduction in peak relative to Business As Usual by Time of Use case (2025)



By 2031, the modelling suggests the peak load reduction from Domestic customers could reach 7.9 GW or 18% of peak domestic demand, as illustrated in Figure 7. It should be noted that this reduction in domestic peak demand exceeds the system level reduction, since some of the shifted load leads to increased demand in other periods.

Figure 7 - Reduction in peak relative to Business As Usual by Time of Use case (2031)



SME Level

The results of the modelling show there is no or limited reduction of the peak demand for the SME sector over ED1 and ED2 periods regardless of the scenario analysed due to lower LCT uptake and lower consumer responsiveness at peak when compared with the Domestic sector. Based on our review of the trials, the main barrier was perception that it was not possible to move usage to other times.

Impact of high wind penetration

Finally, we assessed the impact of customers on dynamic tariffs responding to very low prices in the future with very large volumes of wind on the system, so called wind following. The modelling shows the effects are relatively small, in the context of significantly growing demand associated with LCTs, and unlikely to create new demand peaks greater than the traditional peak periods. However, local network constraints could be created where there are concentrations of LCTs and customers on dynamic tariffs.

2 Introduction

2.1 Background

In March 2012, the Energy Networks Association (ENA) published analysis showing £1.3bn of potential network related benefits from smart metering. This analysis was updated in March 2013. Since the original analysis was performed, there are a number of changes that have implications for the benefits identified by the analysis. Specifically:

- The data security architecture for the Data and Communications Company (DCC) means that there are restrictions on the load control actions that the DNOs can take directly.
- The final Smart Metering Equipment Technical Specifications version 2 (SMETS2) means that the DNOs will not be able to deliver some of the benefits identified by the analysis.

The ENA's latest analysis shows £1.6bn of benefits in total over the RIIO ED1(2015-2023) and ED2 (2023-2031) periods, which is a slight increase on the March 2012 analysis, even when the benefits no longer available as a result of the smart metering system security architecture and the SMETS2 definition are removed. The increase in benefits is mainly related to higher value attributed to the reduced LV network losses due to improved load factor. Of the benefits included in the latest analysis, the two largest components are:

- Avoided, deferred or reduced requirement for reinforcements in the distribution networks due to demand reduction and shifting. In real (i.e. neither inflated nor discounted) terms, £204m of benefits are attributed to TOU tariffs[1] and £272m of benefits are attributed to direct load control over the ED1 and ED2 periods.
- Reduced network losses, also resulting from load shifting away from the peak. This yields £787m in benefits[2] on an undiscounted basis, and does not require direct DNO control to deliver these benefits.

The £272m of benefits attributable to direct load control would only be realised where agreements between customers and suppliers delivered a response that aligned to the DNOs' benefits case. The remaining benefits are heavily dependent on supplier-led implementation of ToU tariffs.

The roll-out of smart meters will increase the opportunities for suppliers to develop ToU offerings and demand side response (DSR) products for their customers. Smart meters, supported by the in-home display will allow consumers to follow their electricity consumption, and control their consumption in response to price signals either manually or through in-home automation.

Alongside preparations for the mass roll-out of smart meters, suppliers in the UK are undertaking trials to assess customer response to ToU tariffs and the potential benefits that could be delivered through reduced consumption and demand shifting. One of the key benefits for suppliers will be to balance their contractual position in the market and refine their procurement strategy. The electricity price is a direct driver for

[1] Note this compares to £44m of benefits identified in the January 2013 Impact Assessment published by DECC.

[2] This compares to £521m of benefits attributed to reduced losses in the January 2013 Impact Assessment published by DECC.

demand response, especially during peak times. Demand reduction and shifting will help suppliers avoid purchasing expensive peak electricity, which in turn could reduce the requirement for investment in new generating capacity. For DNOs, such behaviours will reduce peak demand on their networks, reducing network losses and the requirement for network reinforcements.

These benefits should feed through to consumers as it allows suppliers to procure electricity more cheaply and compete on customer pricing. However, the level of suppliers' benefits will be dependent on the customer behaviour and response to price signals, and the availability of equipment in consumers' homes to automate load shifting.

We can see from the majority of trials (e.g. UK trails, Irish trial, US trials) reviewed for this analysis that the two main ToU tariff forms usually proposed by suppliers to consumers are:

- **Static Time of Use tariff (SToU):** customers are charged different rates depending on the time of day. The electricity meter has at least two registers, and switches between the two based on the time of day or week.
- **Critical Peak Price (CPP)**: a dynamic option which allows the supplier to call a limited number of events during pre-specified time periods based on short-term market conditions. Participants pay a much higher (critical peak) price for all usage during the event hours but a lower price at other times.

A third measure - **Direct Load Control (DLC)** - allows a third party (either supplier or network operator) to have direct control on certain customer loads, providing the opportunity to switch loads off during peak periods or increase demand at times of excess generation. Although DLC has the potential to provide significant benefits to suppliers and/or network operators, it requires consumer buy-in and the installation of specific equipment on consumers' appliances. Based on our analysis of previous and current UK trials, we can see there is currently a lack of DLC offers from suppliers in the UK.

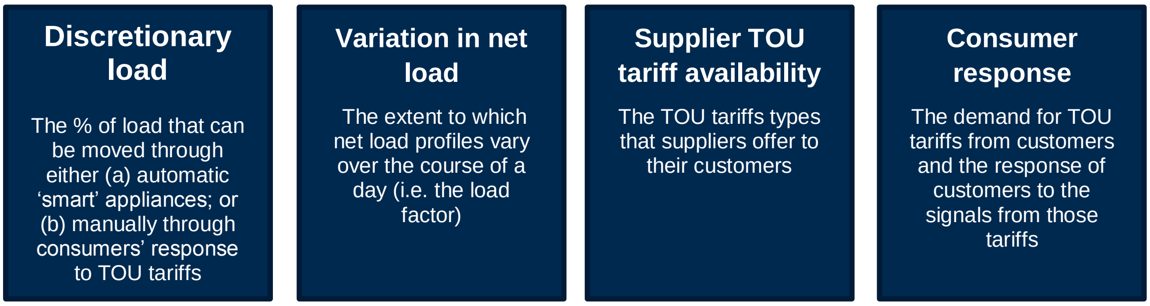
Even if we do not see a real interest in the near term, we believe that this form of dynamic tariff could be developed in the future as experience in the US has shown. For the purposes of this study we have assumed that DLC tariffs are delivered through real-time pricing to the customers' meter, with in-home automation controlling load shifting across appliances. Hence, demand on DLC tariffs respond to system supply/demand conditions, reflected in market prices, rather than local network conditions.

2.2 Objective of the study

In the context of this dependency on supplier-led initiatives, ENA asked Baringa Partners to provide analysis of the likely amount of load reduction and shifting at the time of network peak that might actually be achieved from Domestic and Small and Medium Enterprise (SME) customers over the RIIO-ED1 and ED2 periods. This analysis will be used in conjunction with analysis being prepared by DNV KEMA and by EA Technology (EATL) to update the ENA's estimates of the likely benefits that can be realised by DNOs as a result of both avoided reinforcement costs and reduced network losses related to ToU tariffs offered by suppliers.

Figure 8 gives an overview of the analytical framework that we used for the analysis to estimate the load reduction and shifting that might be achieved as a result of supplier-led initiatives enabled by smart metering. The figure presents the key components that drove that analysis.

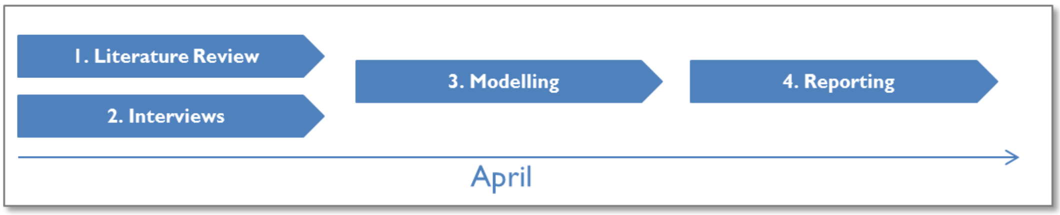
Figure 8 Overview of analytical framework



2.3 Approach

The Smart Metering Load Shift analysis was split into four phases in order to meet the above objectives, as shown in Figure 9.

Figure 9 - Approach



1. Literature Review

The objective of the literature review was to analyse relevant literature, focusing on national and international smart meter and DSR trials in order to understand how Domestic and SME consumers react to differentiated prices and improved information about their energy consumption.

2. Consultations

In parallel to the literature review, we completed several interviews with Baringa consultants who are advising energy suppliers on their smart meter roll-out programmes. It provided us with visibility of the emerging results from the early roll-out of smart meters from a number of the large energy supplier smart roll-out programmes.

3. Modelling

Using Baringa's GB electricity market model, constructed using PLEXOS, we analysed the extent to which consumers may respond to SToU and dynamic tariffs (CPP and DLC), focusing on a week of peak demand. The model estimates the impact of the resulting load reduction and load shifting on peak demand.

In performing our analysis we modelled three different cases for the uptake of ToU tariffs in addition to a Business As Usual (BAU) case, in conjunction with three different flexibility scenarios based on different levels of uptake of LCTs.

4. Reporting

This report summarises the key findings from the literature review, consultations and modelling phases and is intended to inform DNOs about the potential benefits of ToU tariffs on the potential for avoiding reinforcement costs and reducing network losses.

2.4 Structure of report

The remainder of this report is structured as follows:

- Section 3 explains the study methodology and key assumptions;
- Section 4 presents the main results of our modelling in relation to peak demand reduction and shifting for the Domestic and SME sectors; and,
- Section 5 summarises our conclusions and key messages.

More detailed information on assumptions, customer responsiveness to ToU tariffs and modelling results is included in the Appendix.

3 Methodology and Assumptions

3.1 Introduction

In this section we describe the methodology used for the study and the assumptions behind the scenarios modelled.

3.2 Methodology

3.2.1 Cases and scenarios considered in the modelling

We modelled three different cases for the uptake of ToU tariffs in addition to a Business As Usual (BAU) case (with no ToU tariffs assumed), in conjunction with three different flexibility scenarios based on different levels of demand from LCTs, namely heat pumps, electric vehicles and smart appliances.

The three ToU tariffs cases were as follows:

- ToU1 – In this case, we assume a proportion of customers move from unrestricted tariffs to SToU tariffs
- ToU2 – In this case, we assume a proportion of customers move from unrestricted tariffs to both SToU and DLC tariffs
- ToU3 - In this case, we assume a proportion of customers move from unrestricted tariffs to both SToU and CPP tariffs

For each ToU case, we modelled three different scenarios of demand flexibility:

- Low
- Central
- High

Flexibility is created by the penetration of controllable LCTs, and by consumers responding to price signals created through ToU tariffs. The Low, Central and High flexibility scenarios refer both to the penetration of LCTs and the level of uptake of ToU tariffs by consumers. Whilst the High flexibility scenario is associated with high uptake of LCTs and hence higher electricity demand overall, the flexibility of the LCT demand means that peak demand does not increase as much as total demand. Hence, the change in peak demand in the High flexibility scenario when compared with the Business As Usual case is a function of higher LCT demand (pushing peak load up), but with higher responsive of consumers through greater uptake of ToU tariffs (shifting load and bringing the peak down).

Table 1 shows the flexibility scenarios and years modelled. The cases involving dynamic CPP and DLC tariffs, ToU2 and ToU3, are not modelled in 2015 due to an assumption on the low penetration rates in early years.

Table 1 - Scenarios modelled

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	✔	✔	✔	✔
L	ToU1	✔	✔	✔	✔
L	ToU2		✔	✔	✔

L	ToU3		✔	✔	✔
C	BAU	✔	✔	✔	✔
C	ToU1	✔	✔	✔	✔
C	ToU2		✔	✔	✔
C	ToU3		✔	✔	✔
H	BAU	✔	✔	✔	✔
H	ToU1	✔	✔	✔	✔
H	ToU2		✔	✔	✔
H	ToU3		✔	✔	✔

Assumptions for tariff uptake under each of the flexibility scenarios are summarised in Table 14 in Section 3.3.4. Assumptions on the responsiveness of customers to ToU tariffs are detailed in Table 15 and Table 16 in Section 3.3.4.

3.2.2 Modelling approach

We adopted the following steps in modelling the impact of ToU tariffs on demand:

1. **Fixed demand model**: This model projects the future evolution of demand and demand shape using assumptions on underlying growth, energy efficiency and uptake of LCTs assuming no ToU tariffs (i.e. BAU). This demand profile is used as the basis against which demand reduction and shifting are measured.
2. **Static Time of Use load shifting model:** A simple shifting model was used to assess the impact on the demand profile from customers responding to SToU tariffs based on a penetration rate of customers by tariff. The inputs to the model are: BAU demand profiles after assumed demand reduction; time and duration of peak period window; levels of peak and annual load reduction from customers on SToU tariffs. The model shifts the appropriate level of demand out of the peak periods and redistributes across the off-peak periods – weighted towards off-peak periods with higher demand. This is performed independently for each demand source. The effect is to reduce demand at peak times but increase slightly the demand at other times, particularly the periods just outside of the peak period each day.
3. **Dynamic tariff load shifting model:** The response of customers on dynamic tariffs (CPP and DLC) is modelled through simulation of the GB electricity system in PLEXOS for Power Systems. PLEXOS is a leading electricity market simulation tool allowing detailed modelling of system dispatch and price setting. It is used globally by system operators, regulators, generation companies, transmission companies, consultants and academics for operations, planning and risk, market analysis and transmission network analysis. Key features of the instance of PLEXOS used for this study include:
   - Over 450 generating units in GB, together with a simplified representation of interconnected markets
   - Plant dynamics (e.g. minimum run times), part load heat rates (thermal efficiency by output level) and start costs incorporated for thermal plant
   - Regional onshore and offshore hourly wind load profiles
   - Full 365*24 hour modelling using daily simulation steps, with outages and emission limits optimised on an annual basis
   - Starting demand profiles fed from the SToU load shifting model

- The flexibility of heat pumps, electric vehicles and smart appliances is included in PLEXOS, and the model optimises generation and available flexible demand to ensure least system cost (ignoring in this case transmission constraints), whilst ensuring all demand is served

For background information on the electricity system, we used the April 2013 update of the Redpoint GB Reference Case, our central view of the development of the GB electricity market to 2030. Key assumptions include:

- A projection of future capacity mix
- A projection of commodity prices
- Impact of policies (e.g. EMR)

More information is available in the Appendix – Section A.

3.3 Assumptions

In this section, we outline the key assumptions for each component of the analysis:

1. Electricity demand profile, including energy efficiency measures
2. LCT uptake including:
    - Heat pumps
    - Electric vehicles
    - Smart appliances
3. Different rates of uptake of ToU tariffs and customers' response to these

3.3.1 Data sources

We reviewed a comprehensive list of studies, trials and scenarios, and extracted, to the extent possible, appropriate starting assumptions for the analysis. These are summarised in Table 2 below.

Table 2 - Data sources

Input assumptions	Sources
• Development of the GB electricity market to 2030	• Redpoint GB Reference Case, April 2013 update
• Demand growth and profiles	• Elexon hourly demand profiles, 2011 (Profile Classes 1-4) • INDO half hourly demand, 2011 • DECC's Updated and Energy and Emissions projections 2012, October 2012
• LCT projections • Heat pump uptake projection • Electric Vehicle uptake projection • Smart Appliance uptake projection	• Assessing the impact of low carbon technologies on Great Britain's power distribution networks, Smart Grid Forum Work Stream 3, July 2012 • Technology Roadmap for Low Carbon HGVs, Ricardo, 2010 • Electricity Systems Analysis – future systems benefits from selected DSR scenarios, DECC (Redpoint/Baringa, Element Energy), July 2012 • Element Energy / NERA report for the Committee on Climate Change, "Achieving

	deployment of renewable heat", April 2011
• Demand Side Response offerings and customer behaviour	• Emerging results from the early roll-out of smart meters from a number of the GB smart roll-out programmes • The Potential of Smart Meter Enabled Programs to Increase Energy and Systems Efficiency: A Mass Pilot Comparison, Vaasa ett, 2011 • Demand Side Response in the domestic sector- a literature review of major trials, DECC, 2012 • Energy Demand Research Project: Final Analysis, AECOM, 2011 • European Smart Metering Landscape Report 2012, SmartRegions • Electricity Systems Analysis – future systems benefits from selected DSR scenarios, DECC (Redpoint/Baringa, Element Energy), July 2012 • Electricity Smart Metering Customer Behaviour Trials Findings Report, CER, 2011

Baringa provided a draft of all assumptions to be used in the modelling to ENA members, and incorporated the feedback received into the final assumptions.

3.3.2 Electricity demand profile

Domestic electricity demand profile

The demand profiles in the domestic sector were generated using a bottom-up model of energy demand in the housing stock. A simplified representation of the housing stock was derived based on ten distinct house types, differing by size, heating system (non-electricity and electricity) and energy requirements. The energy requirements were calculated using a calculation methodology based on SAP2009. The proportion of each of these house types in the stock was based on analysis of housing condition survey data.

Elexon data was used to project electricity demand profiles for domestic consumers out to 2031. The domestic demand profile was derived using Elexon profile coefficients for Profile Classes 1 and 2. For Profile Class 2, both baseline and shifted components of the demand profile were included in order to reflect the impact of Economy 7 electricity tariffs on the overall domestic electricity demand profile. Future demand profiles were created by scaling the normalised profiles with the annual domestic demand projections from DECC's Updated Energy and Emissions Projections (UEPs), published in October 2012. The DECC UEP projections cover the period 2008-2030; demand for 2031 was derived by extrapolating the DECC UEP figures. The DECC UEP figures are for the UK rather than GB, so have been scaled down by 2.7% to remove the portion of demand related to Northern Ireland.

The model forecasts the change in electricity demand over time, based on assumptions regarding the rate of stock growth[3] and assumptions regarding improvements in energy efficiency[4].

The impact of energy efficiency measures are implicit in the DECC UEP projections and were not projected separately. Future uptake of heat pumps, electric vehicles and smart appliances is not included in the UEP figures and so was added separately, as described in Sections 3.3.3.

SME electricity demand profile

SME profiles were developed in a similar manner as for Domestic customers – profile shape from Elexon historic data, Profile Classes 3 and 4, scaled by the DECC UEP projections.

In this case, the most recent DUKES (Digest of UK Energy Statistics) data was used to provide the current electricity consumption in the sector and how it disaggregates between the major end-uses (e.g. HVAC, lighting, computing etc). This was simply then scaled on the basis of DECC's UEP projection for electricity consumption. However, the DECC UEP figures do not give SME demand separate from other commercial demand. For this reason, the annual SME demand level given by the Elexon data was taken for 2011, and grown by the same rate as the DECC UEP "Commercial" demand projections.

Other demand profile

Total system demand profiles were taken for 2011 using National Grid's INDO half hourly data. After scaling to DECC UEP demand levels for 2011, "other" demand was found by subtracting the Domestic and SME profiles from the system profile. This was scaled by the DECC UEP projections for demand excluding Domestic and SME.

Figure 10 shows the demand profiles for each source of demand (Domestic, SME, Other) and the aggregated system level demand for the base year, 2011. Figure 11 shows the DECC UEP projections of annual demand, scaled to a GB basis, and extrapolated to give values for 2031.

Figure 10 - Domestic Electricity Demand profile over peak day 2011

[3] Based on DECC projections for household growth rate

[4] Changes in thermal efficiency have been modelled by assuming a rate of penetration of packages of energy efficiency measures across the stock. This rate of penetration is based on projections for the number of homes to be treated contained within the Heat Energy Strategy. Changes in appliance energy efficiency are based on Market Transformation Programme projections.

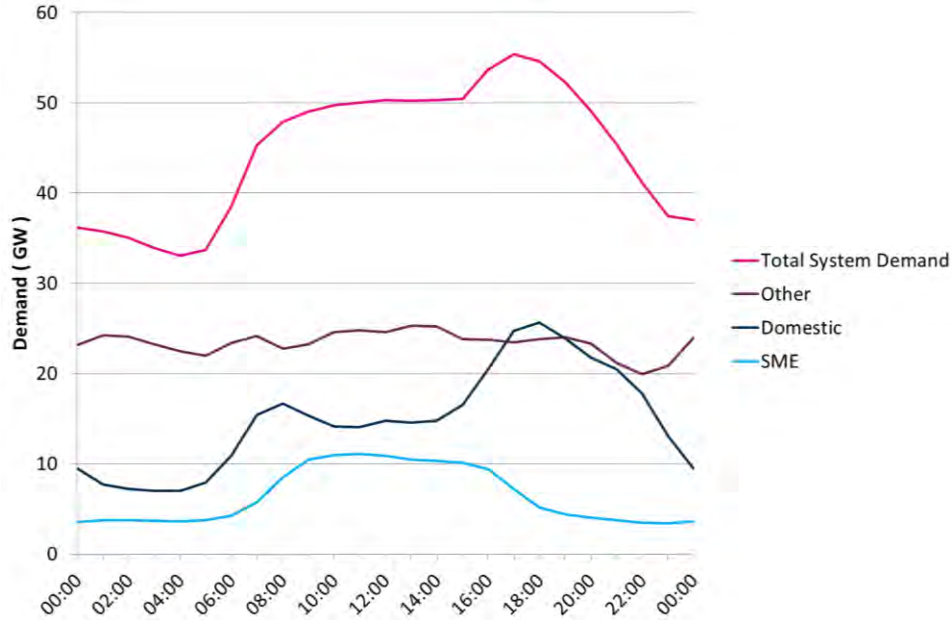
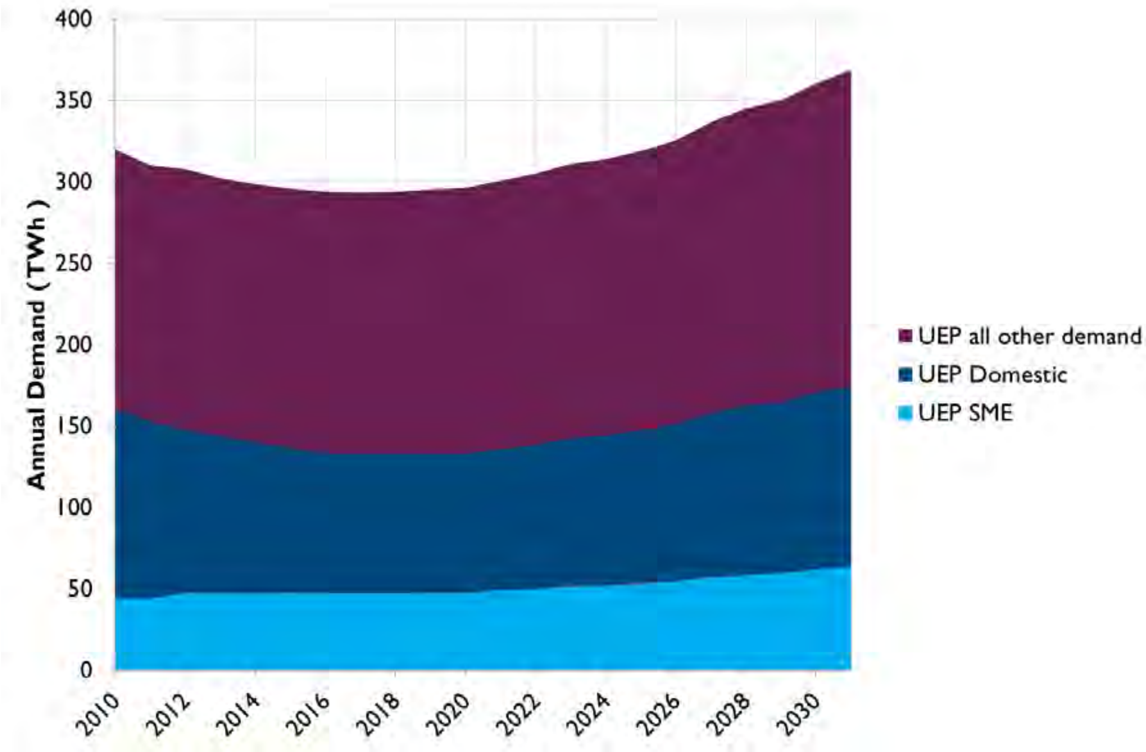


Figure 11 - Demand projections (based on DECC UEP)



3.3.3 Low Carbon Technologies uptake

LCTs include heat pumps, electric vehicles and smart appliances. These three technologies are considered as potentially flexible. Electric vehicles provide flexibility due to the storage capacity of their batteries, which are assumed to be charged overnight, and not fully discharged each day. This allows for within day flexibility, charging at times of low demand, and intraday flexibility – limiting charging on days of high demand and charging more on subsequent days. Similarly, heat pumps with water tanks provide storage in the form of heat in the water, and provide flexibility by heating the water at periods of low demand. The typical storage capacity of heat pumps is of the order of a few hours of heat output. Smart appliances often do not need to be run at a precise time, for example washing machines. Hence, they can provide flexibility by running in response to an external trigger, potentially price. We assume flexible appliance load must be satisfied within a 24 hour period.

The load growth was projected based on the uptake of heat pumps and electric vehicles. This load growth was based on DECC scenarios for the rate of uptake of the technologies, which were used in the Smart Grid Forum Work Stream 3 modelling. DECC provided three scenarios for the uptake of both heat pumps and electric vehicles – low, medium and high which have been included in the modelling. A range of assumptions regarding heat pump and EV performance parameters have been used to generate electricity demand projections on the basis of the DECC uptake scenarios.

In addition to heat pump and EV uptake scenarios, a penetration rate for smart appliances was also developed. Smart appliances are assumed to partially displace conventional wet appliances, tumble driers, …

A set of characteristic demand profile shapes was developed for heat pumps, electric vehicles and smart appliances. The projections of annual consumption for each of these end-uses was then used to scale the profiles (which were normalised by annual demand) in order to generate contributions of these end-uses to the overall domestic demand profile.

Heat pump uptake and electricity demand

Number of heat pumps in operation

Table 3 shows the uptake scenarios for heat pumps, which map onto the flexibility scenarios. Based on the DECC LCT scenarios forecast assumptions, uptake of heat pumps for the Domestic and SME sectors was assumed to follow the same trajectory in each of the three flexibility scenarios over the period to 2020, with relatively limited uptake forecast until the latter part of this decade, before the scenarios diverge after 2020.

Table 3 - Heat pumps number projection by flexibility scenario

Cumulative heat pumps installed (thousands)	2015	2020	2025	2030
Low	0	648.5	886.4	1,147.2
Central	0	648.5	3,129.2	6,266.0
High	0	648.5	3,361.3	7,645.5

Source: Assessing the impact of low carbon technologies on Great Britain's power distribution networks, Smart Grid Forum Work Stream 3, July 2012

Electricity demand profile from heat pumps

The modelling is based on:

- Element Energy renewable heat uptake model (created for the Committee on Climate Change to investigate the uptake of different renewable heat technologies under different policy scenarios)

- Heat pump baseline efficiency (Coefficient of Performance) and efficiency improvement over time from selected studies (*The UK Supply Curve for Renewable Heat*, NERA and AEA for DECC (July 2009); Design *of the Renewable Heat Incentive*, NERA for DECC (February 2010))

Table 4 below provides the coefficient of performance assumptions used. The dominant technology type in the model is Air Source Heat Pumps, Air to Water (ASHP ATW), situated within pre-2012 domestic buildings, with a coefficient of performance of 2.5 on the peak day.

Table 4 – Coefficient of performance of Heat Pumps

Dwelling type	HP Type	COP on peak day
Post 2012 buildings	ASHP ATA	3.4
	ASHP ATW	2.8
	GSHP	3.8
Pre 2012 buildings	ASHP ATA	Not suitable
	ASHP ATW	**2.5**
	GSHP	3.3

Source: Element Energy / NERA report for the Committee on Climate Change, "Achieving deployment of renewable heat", April 2011

Customers currently using gas heating, electrical storage heating with Economy 7, conventional resistive heating or solid or liquid fuels are assumed equally likely to move to heat pumps, although in practice off gas grid customers may be more likely to move to heat pumps than other customers. Consumers moving from gas or liquid or solid fuels will increase total and peak electrical demand. Consumers moving from conventional resistive heating to heat pumps will reduce total and peak electrical demand. Consumers moving from Economy 7 resistive heating to heat pumps will reduce total demand but increase peak demand.

Table 5 shows the annual electrical demand for the Domestic and the SME sectors related to new heat pumps (excludes savings due to displaced resistive heating) under our three flexibility scenarios.

Table 5 - Heat pump electricity consumption for the Domestic and SME sectors

Gross HP Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.00	3.05	4.25	5.74
Central	0.00	3.05	13.02	29.73
High	0.00	3.07	13.99	36.36

The heat pump profile shape was derived using data on thermal demands in a range of real houses collected during the Carbon Trust's micro-CHP field trials. The thermal demand data is aggregated for each day in each month (retaining a split between weekdays and weekends) and for a number of different house types included in the dataset, in an attempt to reflect the impact of diversity on the demand profile shape.

The results illustrated in Table 5 are split between the Domestic and the SME sectors in Table 6 and Table 7.

Table 6 - Heat pump electricity consumption for the Domestic sector

Domestic HP Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.00	2.7	3.7	5.0
Central	0.00	2.7	12.3	28.6
High	0.00	2.7	13.2	35.1

Table 7 - Heat pumps electricity consumption for the SME sector

SME HP Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.00	0.34	0.52	0.74
Central	0.00	0.40	0.71	1.12
High	0.00	0.42	0.78	1.23

Electric vehicle uptake and electricity demand

Based on the DECC LCT scenarios forecast assumptions, Table 8 shows the assumptions on electric vehicle numbers under the three flexibility scenarios. These scenarios are driven by targets for the average emissions of new cars and vans in 2030, under different assumptions. The figures shown in Table 8 include both the Domestic and SME sectors.

Table 8 – Electric vehicle numbers projection by flexibility scenario

Number of EVs on the road	2015	2020	2025	2030
Low	95,475	641,055	1,870,254	3,943,321
Central	126,437	1,032,821	3,336,899	7,151,969
High	219,804	1,629,394	5,120,265	10,526,184

Source: Assessing the impact of low carbon technologies on Great Britain's power distribution networks, Smart Grid Forum Work Stream 3, July 2012

The numbers of EVs include all vehicle technologies (pure electric vehicles, plug-in hybrids, range extended vehicles), different forms of ownership (e.g. fleet, company and private) and both cars and vans.

EV's domestic and SME electricity demand profile

The modelling of electric vehicle profiles was based on DECC assumptions. The data contains splits by vehicle technology, charging speed, and charging location. DECC has made assumptions regarding the relative merits of different electric vehicle technologies and the importance of particular vehicle attributes, such as cost and range, to different kinds of consumers. These scenarios were disaggregated further into different vehicle technologies with associated assumptions regarding usage characteristics (e.g. daily mileage), vehicle efficiency (kWh/km) which was taken from Ricardo's Technology Roadmap, charging characteristics and the location at which they are likely to be charged (i.e. home, work or at public charging points). All these characteristics are important for determining the size of the demand and charging profile that electric vehicles are likely to impose on distribution networks.

Table 9 summarises the overall demand (i.e. demand of any electric vehicle on UK roads) from EVs under our flexibility scenarios between 2015 and 2030.

Table 9 – Demand from EVs by flexibility scenario

Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.2	1.1	3	6.1
Central	0.3	2.2	6.5	12.8
High	0.4	2.8	8.3	16.6

Source: Assessing the impact of low carbon technologies on Great Britain's power distribution networks, Smart Grid Forum Work Stream 3, July 2012

Table 10 and Table 11 respectively provide the electricity demand from EVs for the Domestic and the SME sectors.

Table 10 – Domestic electricity demand from EVs

Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.08	0.61	1.70	3.78
Central	0.16	1.25	3.72	8.10
High	0.18	1.53	4.68	10.33

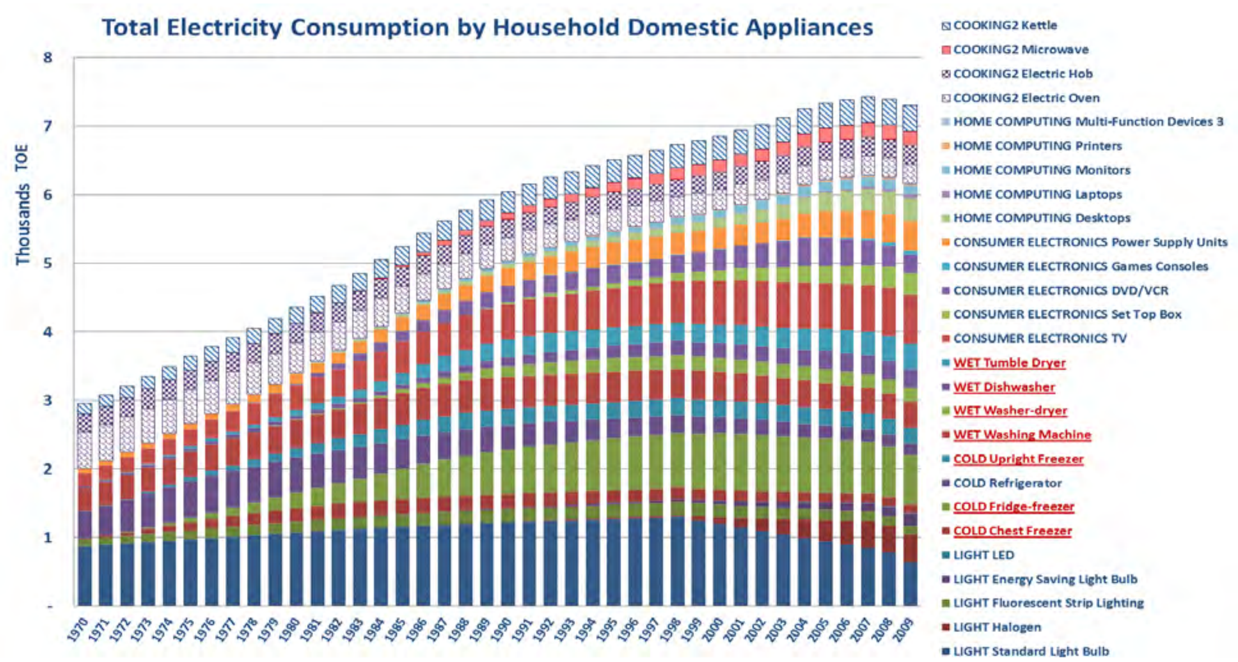
Table 11 - SME electricity demand from EVs

Electricity consumption (TWh)	2015	2020	2025	2030
Low	0.05	0.14	0.25	0.37
Central	0.09	0.29	0.55	0.76
High	0.11	0.36	0.71	0.99

Smart Appliances (SA) uptake and electricity demand

Seven appliance (highlighted in red in Figure 12 below) which could become “smart”, representing around one third of the total domestic appliances consumption in 2009, were analysed . This proportion was used to model the proportion of appliance load which could become flexible.

Figure 12 - Total electricity consumption by appliances



Source: DECC, Energy Consumption in the UK, Domestic data tables, 2010 update (publication URN 10D/802)

We assumed different consumption levels for the Domestic and SME sectors.

The assumed annual domestic demand from smart appliances is shown in Table 12 below. The same assumptions are taken for the three flexibility scenarios. It was assumed that all households that have purchased smart appliances will take up a ToU tariff.

Table 12 - Smart Appliances electricity consumption for the domestic sector

Smart appliances	2015	2020	2025	2030
Electricity consumption (TWh)	0.5	3.1	4.9	7.6

The assumed annual demand from smart appliances for the SME sector is illustrated in Table 13 below. The level of electricity demand is lower than for the domestic sector as usage of smart appliances by SME will be limited to some appliances only. As for the domestic sector, the same assumptions were taken for the three flexibility scenarios.

Table 13 - Smart Appliances electricity consumption for the SME sector

Smart appliances	2015	2020	2025	2030

Electricity consumption (TWh)	0.22	0.44	0.69	1.14

3.3.4 Rate of penetration of ToU tariffs and customer responsiveness by flexibility scenario

Households with LCTs were assumed to take up a ToU tariff offer once they had a smart meter.

It was assumed that households without smart meters will not have any ability to respond to ToU tariffs, other than those already on Economy 7 tariffs. The roll-out of smart meters in the domestic stock is assumed to be complete by 2019, based on DECC's current mandate[5].

1. Rate of penetration of ToU tariffs by flexibility scenario

As explained above, we developed three different penetration rates for ToU tariffs according to the three different flexibility scenarios. These three different flexibility scenarios were then modelled in conjunction with the three different ToU cases. This combination of flexibility scenarios and ToU cases determines the level of switching modelled.

The overall penetration of ToU tariffs across the flexibility scenarios and ToU cases is summarised in Table 14 below. The assumptions are based on DECC's Electricity System Analysis report published in July 2012.

Table 14 - Penetration rate of ToU tariffs by flexibility scenario

Flexibility scenario	ToU case	Tariff	Proportion of consumers on tariffs			
			2015	2020	2025	2031
Low scenario	BAU	No ToU tariff	100%	100%	100%	100%
	ToU1	SToU	8%	22%	25%	31%
		No ToU tariff	92%	78%	75%	69%
	ToU2	SToU	8%	20%	22%	27%
		DLC	0%	2%	3%	4%
		No ToU tariff	92%	79%	75%	69%
	ToU3	SToU	8%	18%	18%	21%
		CPP	0%	2%	6%	9%
		No ToU tariff	92%	80%	75%	69%
Central scenario	BAU	No ToU tariff	100%	100%	100%	100%
	ToU1	SToU	8%	23%	34%	48%
		No ToU tariff	92%	77%	66%	52%
	ToU2	SToU	8%	21%	30%	42%
		DLC	0%	2%	4%	6%
		No ToU tariff	92%	77%	66%	52%

[5] Note that the analysis was undertaken prior to the recently announced extension to 2020.

	ToU3	SToU	8%	17%	24%	32%
		CPP	0%	3%	10%	16%
		No ToU tariff	92%	79%	66%	52%
High scenario	BAU	No ToU tariff	100%	100%	100%	100%
	ToU1	SToU	8%	24%	40%	64%
		No ToU tariff	92%	76%	60%	36%
	ToU2	SToU	8%	20%	33%	52%
		DLC	0%	4%	8%	12%
		No ToU tariff	92%	76%	60%	36%
	ToU3	SToU	8%	18%	28%	45%
		CPP	0%	3%	12%	19%
		No ToU tariff	92%	78%	60%	36%

Source: Electricity Systems Analysis – future systems benefits from selected DSR scenarios, DECC (Redpoint/Baringa, Element Energy), July 2012; Baringa analysis

The same assumptions regarding smart meter roll-out and take up of the various ToU tariffs as applied in the Domestic sector were also assumed for the SME sector.

2. Incentives on suppliers to offer ToU tariffs

There are two considerations for assessing the likelihood that suppliers will offer ToU tariffs.

On one hand, ToU tariffs offer new opportunities for suppliers for demand management. The motivation of suppliers to propose ToU tariffs is explained by the potential reduction of their purchasing costs and a better management of price risks. This will be reinforced by the fact that volatility and variability in the wholesale market will likely increase in the future.

On the other hand, suppliers' offers will be driven by demand from customers. Customers will evaluate the new tariff offerings based on the potential benefit for them. They will look for lower bills, which is likely to happen if suppliers share their procurement benefits with them and if customers are able to shift their consumption in response to price signals. This willingness to be flexible is largely attributed to the financial incentives on offer via the ToU tariff.

Based on projected wholesale price shape between 2020 and 2031, our analysis suggests that suppliers should be willing to offer a price differential of around £20/MWh on SToU tariffs and a CPP price premium of around £75/MWh. The trial data suggests that customers would respond to these levels of price differential. For customers on DLC tariffs, it is assumed that the in-home automation will allow customers to capture the best prices within the operational constraints of each appliance type.

It should be noted that Ofgem's Retail Market Review (RMR) may place constraints on the number of different ToU offerings from each supplier.

3. Customer responsiveness

A review of national and international trials was performed in order to assess the impact of ToU tariffs on consumer behaviour. Detailed results of the analysis are available in the Appendix – Section B.

Based on the analysis, we made assumptions on demand reduction and shifting in response to ToU tariffs, respectively for the Domestic and SME sectors.

Domestic demand reduction

Recent trials in UK (Customer Led Network Revolution trials) and Ireland (CER) show a reduced usage (up to 3%) of the domestic electricity consumption in addition to demand shifting. This can be explained by an increased awareness on the part of the consumer (reinforced by the in-home display) surrounding their electricity consumption. We consequently assumed a decrease in consumption of 2% for customers with ToU tariffs in the Domestic sector. The decrease of consumption was applied to a proportion of the domestic Business As Usual demand profile before shifting occurs under the relevant ToU cases. This reduction is in addition to improving appliance and lighting technology efficiencies over the period.

SME demand reduction

We assumed no demand reduction associated with ToU tariffs in the SME sector. In the CER trial, the deployment of ToU tariffs and DSR stimuli were found to reduce overall electricity usage by 0.3% which was not confirmed on a long term basis. (The next period of the trial showed an increase of consumption.)

Domestic demand shifting

Table 15 shows the assumptions used for increasing customer responsiveness for normal and smart appliances over time. Customers with normal appliances are expected to increasingly adapt their consumption manually through SToU and CPP tariff signals, and with smart appliances through in-home automation responding to tariff price signals.

Table 15 – Peak demand shifting percentage by type of ToU tariff - Domestic

ToU tariff measure	Responsive load	Customer responsiveness			
		2015	2020	2025	2031
SToU	Normal appliances	5%	10%	15%	20%
	HP/EV/SA	10%	20%	30%	40%
CPP	HP/EV/SA	30%	40%	50%	60%
DLC	HP/EV/SA	100%	100%	100%	100%

Source: Electricity Systems Analysis – future systems benefits from selected DSR scenarios, DECC (Redpoint/Baringa, Element Energy), July 2012

SME demand shifting

Results from the Irish trial show that ToU tariffs and DSR stimuli shifted peak demand by around 2.2%. For SMEs, the main barrier was perception that it was not possible to move usage to other times. The Customer-Led Network Revolution trial in the UK also suggested that SMEs signing up for ToU tariff appear unwilling to change behaviour to any great extent, particularly if there is an impact on business operation.

As illustrated in Table 16, we assumed a smaller responsiveness for SME than for the Domestic sector, which is aligned with results of recent trials in earlier years. However, the growth rate in responsiveness over time is comparable to the Domestic sector assumptions.

Table 16 - Peak demand shifting percentage by type of ToU tariff - SME

ToU tariff measure	Responsive load	Customer responsiveness			
		2015	2020	2025	2031

SToU	Normal appliances	2%	4%	6%	8%
	HP/EV/SA	4%	8%	12%	16%
CPP	HP/EV/SA	10%	20%	30%	40%
DLC	HP/EV/SA	100%	100%	100%	100%

Customer responsiveness on the long term

The trial results in general did not show a clear trend in customer responsiveness over the long term. However, the majority of trials did not last more than two years and hence it is difficult to draw strong conclusions.

However, we assumed the customer responsiveness will be enduring in the long term given the demonstrable savings in bills from the tariff types modelled.

4 Results

4.1 Overview

This section presents the main results from the modelling. Based on the assumptions detailed above, the objective of this section is to provide a view on the likely amount of peak demand reduction, that may be achieved through permanent reduction and demand shifting as a result of ToU tariffs offered by suppliers across the Domestic and SME sectors over the RIIO-ED1 (2015-2023) and ED2 (2023-2031) periods.

4.2 Peak demand reduction

As described above, we assumed a 2% permanent reduction in demand in the Domestic sector resulting from ToU tariffs, but no permanent reduction in the SME sector. This permanent demand reduction is applied to the relevant demand profiles before the demand shifting analysis. The reductions in peak demand shown in this section combine the permanent demand reduction and the results of demand shifting.

4.3 Peak demand shifting

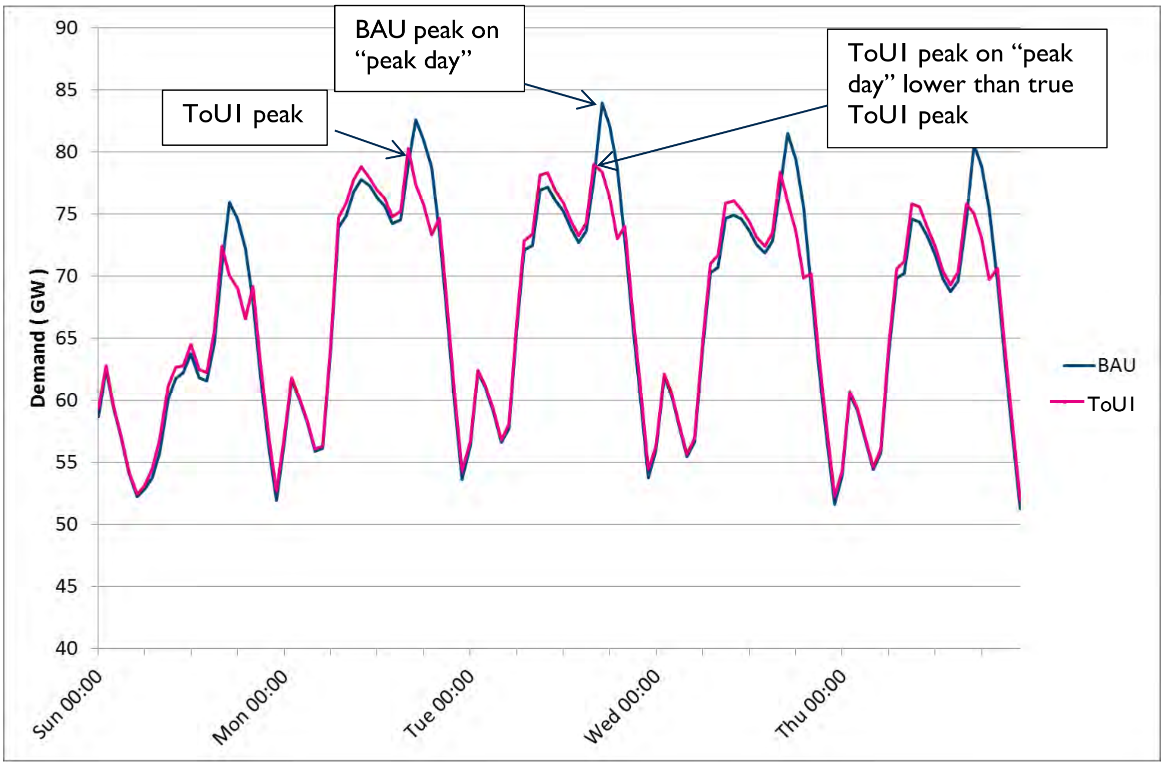
Consumers on different tariffs have differing impacts on peak demand, depending on the penetration rate by tariff within the Domestic and SME sectors and the customer responsiveness to those tariffs, as defined in the assumptions.

Below we show the modelled impact of ToU tariffs on reducing peak demand by sector. The results show the combination of permanent demand reduction and demand shifting.

We have assessed the demand shifting for a representative five day period during a winter cold spell. The level of peak demand depends on the level of base demand (grown from 2011 profile data) and LCT uptake, and so varies by flexibility scenario and year. However, in the scenarios presented here the peak day is always in either December or January. By including two days either side of the peak day we can validate that the effect of the demand shifting does not result in the creation of a new peak elsewhere.

Figure 13 below shows the danger of modelling the peak day only. The system peak demand is reduced by 5 GW on the peak day under the ToU1 case, for example. However, a new system peak demand is created on the preceding day, and is only 4 GW lower than the previous system peak.

Figure 13 – Impact of modelling the peak week in 2031



4.3.1 Impact of ToU tariffs on Domestic peak demand

The results presented in this section here are for the Domestic sector only, and do not represent the reduction in peak demand seen at a system level, which may be higher or lower depending on the timing of Domestic and system peaks.

The modelling shows that the three ToU tariffs cases start impacting the peak loads in 2020 with an average reduction in peak demand of around 0.4 GW. In 2025, the Low flexibility scenario indicates a decrease of the peak demand of 0.8 GW while the Central and High flexibility scenarios show a peak reduction of between 2 and 3 GW. In 2031, the peak demand reduces by 1.7 GW in the Low flexibility scenario and by 4 and 5 GW in the Central and High flexibility scenarios respectively.

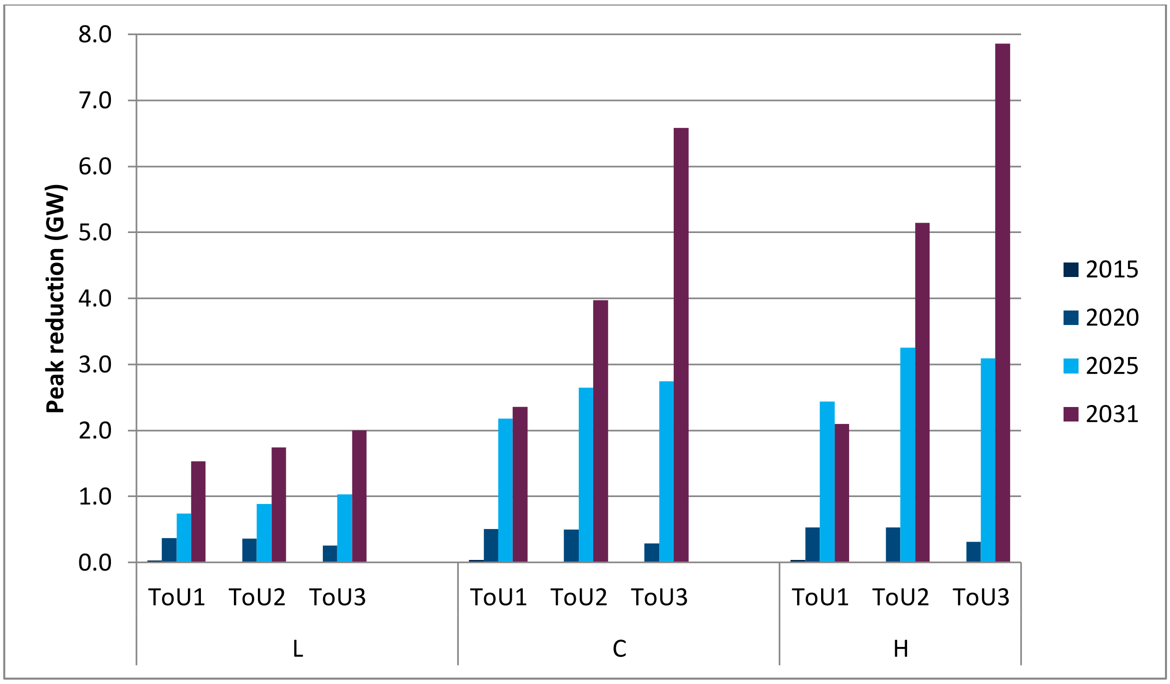
Figure 14 shows the peak demand reduction for each ToU tariff case, flexibility scenario, and year, for the Domestic sector alone.

Several points are worth noting from this chart:

- The ToU tariff benefits increase over time, due to the assumed increase in LCTs and the increasing penetration rate of ToU tariffs.
- There is no peak demand reduction associated with ToU tariffs before 2015, due to very low numbers of consumers on ToU tariffs and a limited impact in 2020.
- The permanent demand reduction of 2% related to the use of ToU tariffs is included in the results of the chart. However, the impact is very limited as the demand reduction is low and is only applied to the minority of customers with ToU tariffs
- In 2025, the lowest peak demand reduction is around 0.7 GW (3% of peak Domestic demand) in the ToU1 case and the highest peak demand reduction is 3.3 GW (12%) under the ToU2 case.

- By 2031, the modelling suggests the peak demand reduction from Domestic customers could reach 7.9 GW or 18% of peak Domestic demand. It should be noted that this reduction in Domestic peak demand is greater than the reduction seen at the system level, since some of the shifted load leads to increased demand in other periods.
- The lowest peak demand reduction in 2031 is 1.5 GW (5%) under the ToU1 case.
- CPP tariffs lead to the greatest peak demand reduction while SToU give the lowest.
- The peak demand reduction under the ToU1 case actually decreases between 2025 and 2031 in the High flexibility scenario. This is due to a widening peak period, compared with the 5-8pm window in the assumed tariff, and shifted demand adding to a new peak at 4pm.

Figure 14 – Reduction in Domestic peak demand relative to Business As Usual



The figures below show peak demand from Domestic customers under each ToU case relative to BAU for the three flexibility scenarios.

Figure 15 - Impact of ToU1 on Domestic peak demand

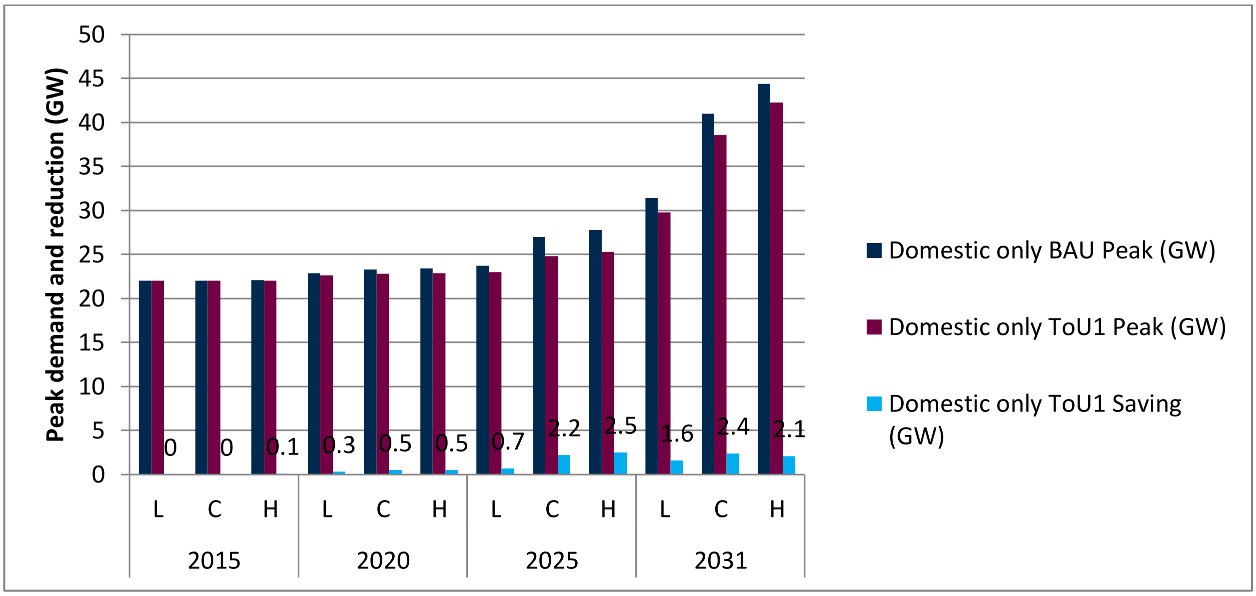


Figure 16 - Impact of ToU2 on Domestic peak demand

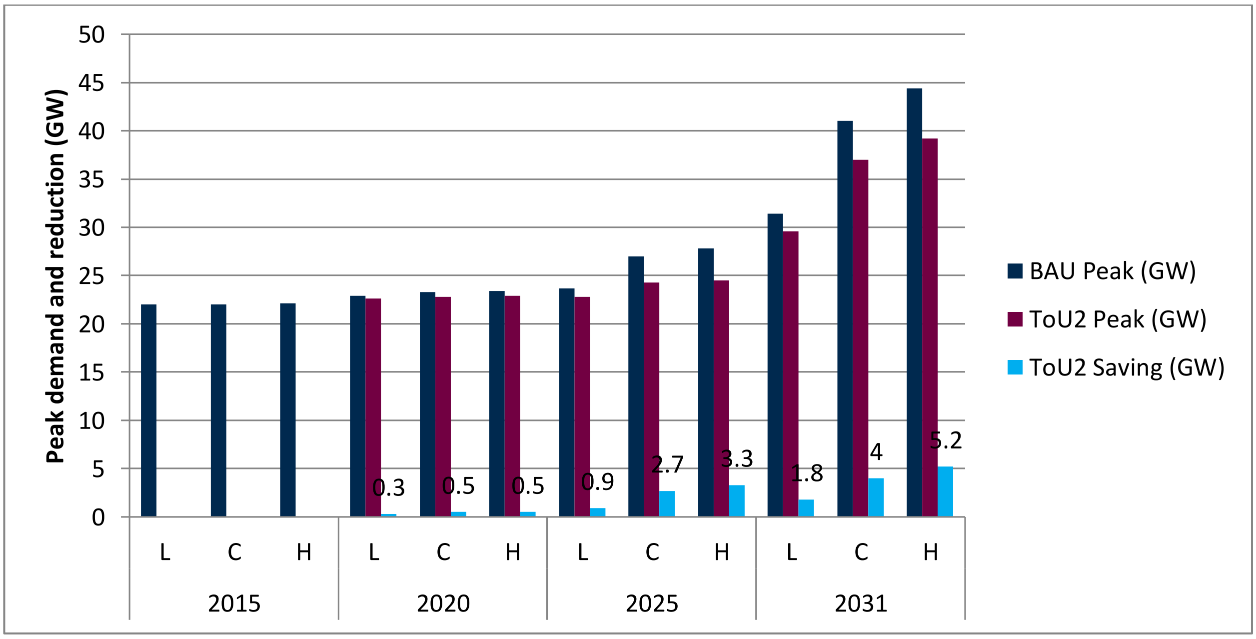
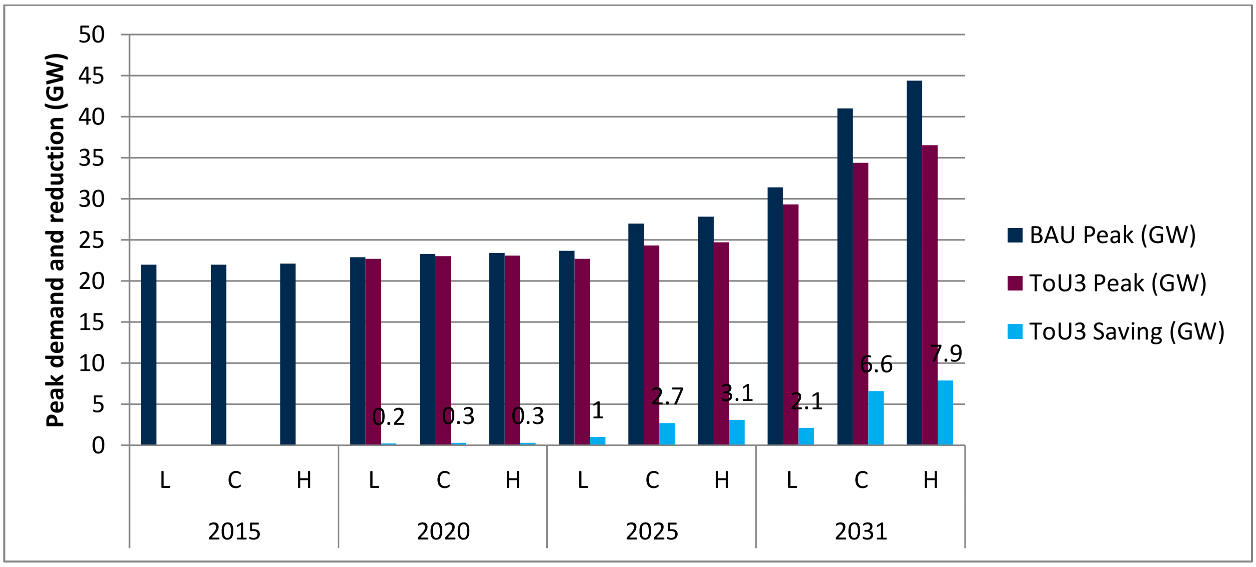


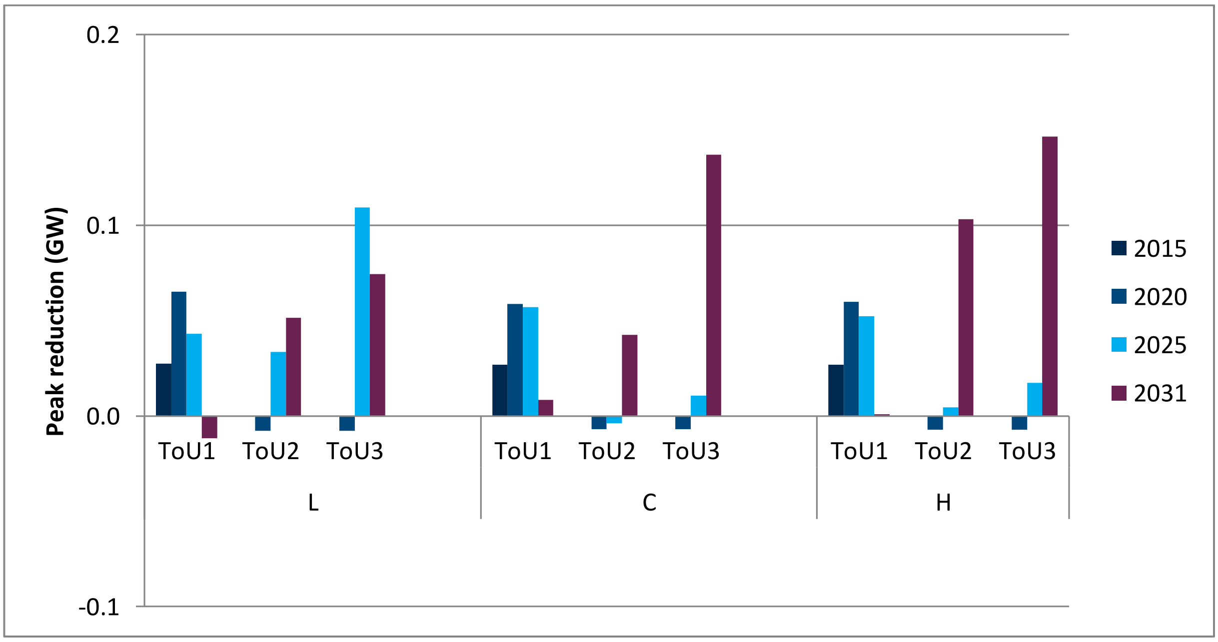
Figure 17 - Impact of ToU3 on Domestic peak demand



4.3.2 Impact of ToU tariffs on SME peak demand

Figure 18 shows the modelled reduction in peak demand for the SME sector resulting from ToU tariffs. The peak demand reduction in all cases and scenarios is very low, between 0 and 0.2 GW. The ToU tariff benefits are limited for the SME sector.

Figure 18 - Reduction in SME peak demand relative to Business As Usual



Figures showing the peak SME demand under the three ToU cases relative to BAU are shown in the Appendix.

4.4 Effect of shifting Domestic and SME loads on the system (overall) demand peak

The figures above show the reduction in demand when looking at Domestic and SME sectors individually. When looking at a system level it is incorrect to sum the demand reduction figures above, as these may not occur in the same time period. For demand shifting, demand reduced in one time period must be balanced by an increase in demand in other periods.

In all ToU cases, there is a proportion of customers on SToU tariffs. Over the peak demand period 5-8pm their demand is reduced, but is increased at other times, most markedly at 4-5pm and 8-9pm. As a result the system peak may by moved outside of the 5-8pm window, although the reduction in system peak demand may be less that that observed in the Domestic sector alone given higher demand from other sectors during the times that Domestic load is shifted to, particularly 4-5 p.m. In the ToU2 and ToU3 cases there are customers on dynamic CPP and DLC tariffs, who respond to real-time price signals. The amount of load shifting is dependent on system conditions, which become increasingly influenced by the output from intermittent renewables as the generation mix shifts to more low carbon generation.

Figure 19 shows this effect, for the ToU1 case under the High flexibility scenario in 2031. The system peak has shifted from 5pm to 4pm due to SToU, and the system peak reduction (5.4 GW) is lower than the reduction in peak Domestic demand (6.2 GW).

Figure 19 - Peak demand shifting for a typical peak day in 2031 (ToU1 case, High flexibility scenario)

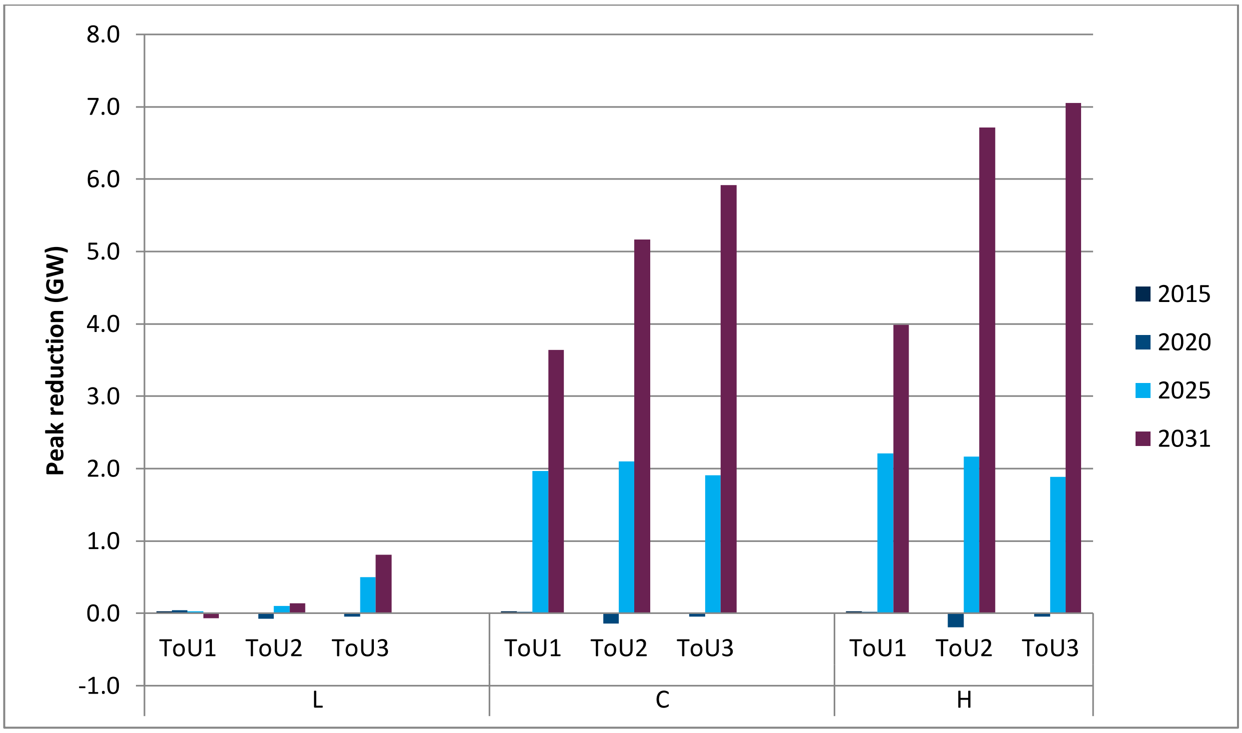
In some scenarios, this effect may result in very low system peak demand reduction, or even an increase in system peak demand.

Figure 20 shows the peak demand reduction at the system level, in all scenarios and years. It can be seen that in 2015 and 2020 the low uptake assumptions for LCTs and TOU tariffs result in little change in the peak demand. From 2025, there is a more significant reduction of the overall peak demand for the three ToU cases:

- In 2025, the ToU1 case provides the lowest peak demand reduction, with limited peak demand reduction in the Low flexibility scenario. Under the ToU2 and ToU3 cases the reduction in system peak is 2.2 GW in 2025. This would represent a reduction in peak system demand of approximately 3%.
- In all flexibility scenarios in 2031, the ToU3 case provides the biggest peak demand reduction, up to 7.1 GW or approximately 8% of peak demand in the High flexibility scenario.

This implies that the impact of ToU tariffs for ED1 is limited while peak demand reduction becomes significant for ED2. Additional information about the % of peak reduction by scenario is available in Section C.8 in the Appendix

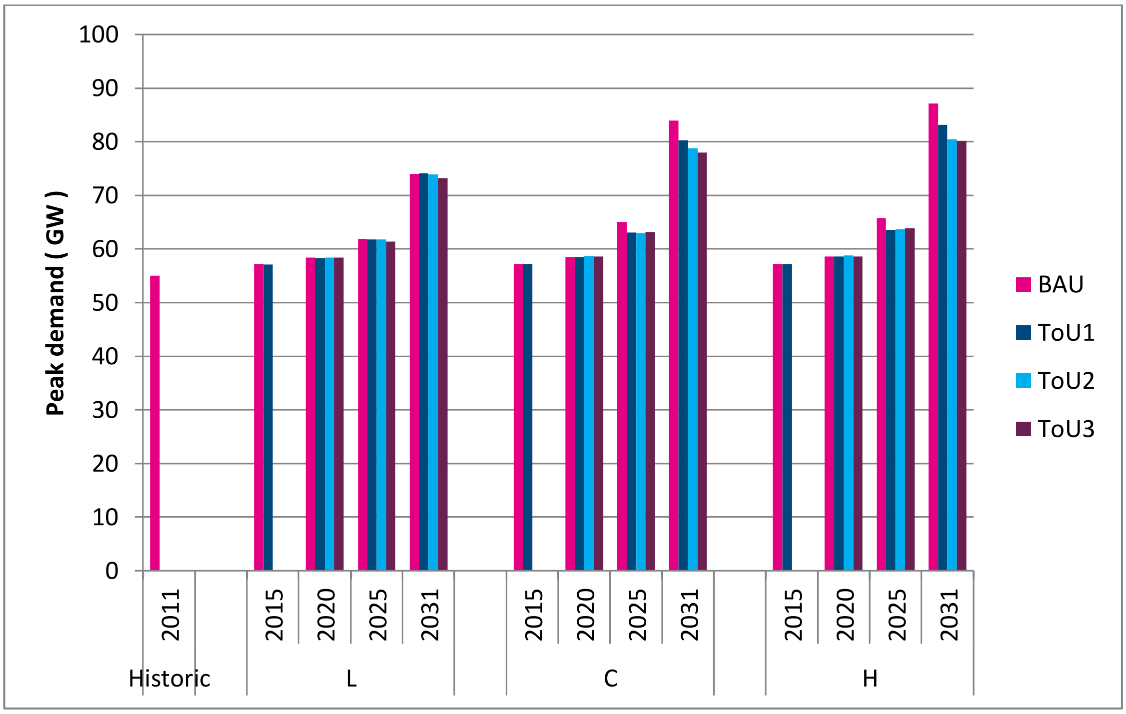
Figure 20 - Peak demand reduction



It is useful to set in context the potential reductions in peak demand associated with ToU tariffs against the increases in peak demand expected, not least since it is the LCTs which provide much of the flexibility that is contributing most to the increasing demand in the future.

Figure 21 represents the peak demand under BAU and each ToU case for the three different flexibility scenarios over the ED1 and ED2 periods and compares this to historic 2011 peak demand. This shows that the additional peak reduction associated with the higher flexibility cases is not sufficient to offset the increasing underlying demand, but that ToU tariffs are important in mitigating the increase.

Figure 21 - Peak demand evolution and peak savings by scenario



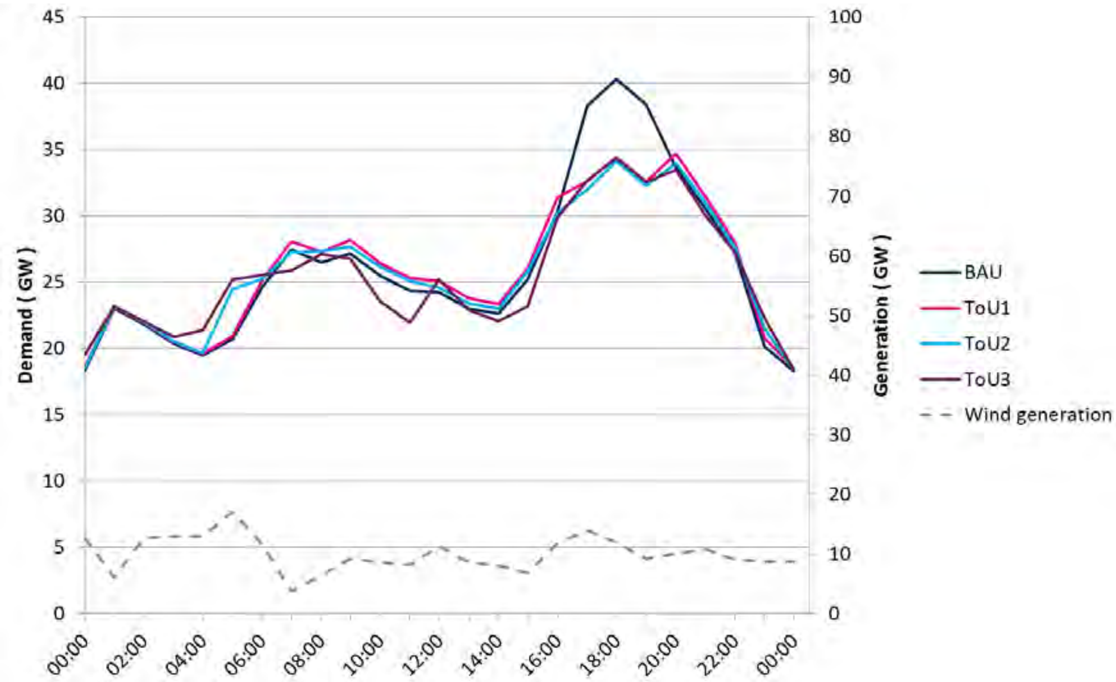
4.5 Wind sensitivity

To test the effect of wind on dynamic tariff demand, a Low Wind and High Wind case were modelled for 2031 (the last year of ED-2), using the Central flexibility scenario as the base case. Customer demand on dynamic tariffs may follow pricing signals influenced strongly by the level of wind output as well as the level of system demand. If there is high wind output during periods of peak demand, flexible load rather than shifting away from peak may shift to follow low wind driven prices, possibly leading to an overall increase in peak demand rather than the reductions seen in the core results above.

A weekday in winter was chosen as an example with increases in wind output around 5am, and 5pm. Total daily wind output over the day was moderate in the Base case for this sample day, with a capacity factor of approximately 30% In the High Wind case the wind output scaled up by 300% when compared with the base case, to a very high load factor of 90% through the day. In the Low Wind case the wind output was scaled down by 33% when compared to the Base case, to a load factor of 10%.

Figure 22 shows the Domestic demand profile for the typical winter day, with base wind. Domestic demand is shown alone, as the bulk of demand shifting occurs from the Domestic sector and this chart allows the effects of wind to be seen more clearly. Wind generation is plotted on a second y-axis for clarity. It can be seen that the higher wind output at 5am results in a shift of some flexible demand under cases ToU2 and ToU3, relative to the ToU1 case which does not include dynamic tariffs. Higher wind at 5pm does not result in higher demand under ToU2 and ToU3 since this does not have a material impact on price.

Figure 22 - Typical winter day, 2031 Central flexibility, Base Wind



Error! Reference source not found. shows the Domestic demand profile with in the Low Wind case. The demand profile for tariff scenarios containing consumers on dynamics tariffs (ToU2, ToU3) is slightly "smoother" when compared with the same profiles in the Base Case. With low wind output, flexible demand is influenced mainly by system demand, which is less volatile than intermittent wind.

Figure 23- Typical winter day, 2031 Central flexibility scenario, Low Wind

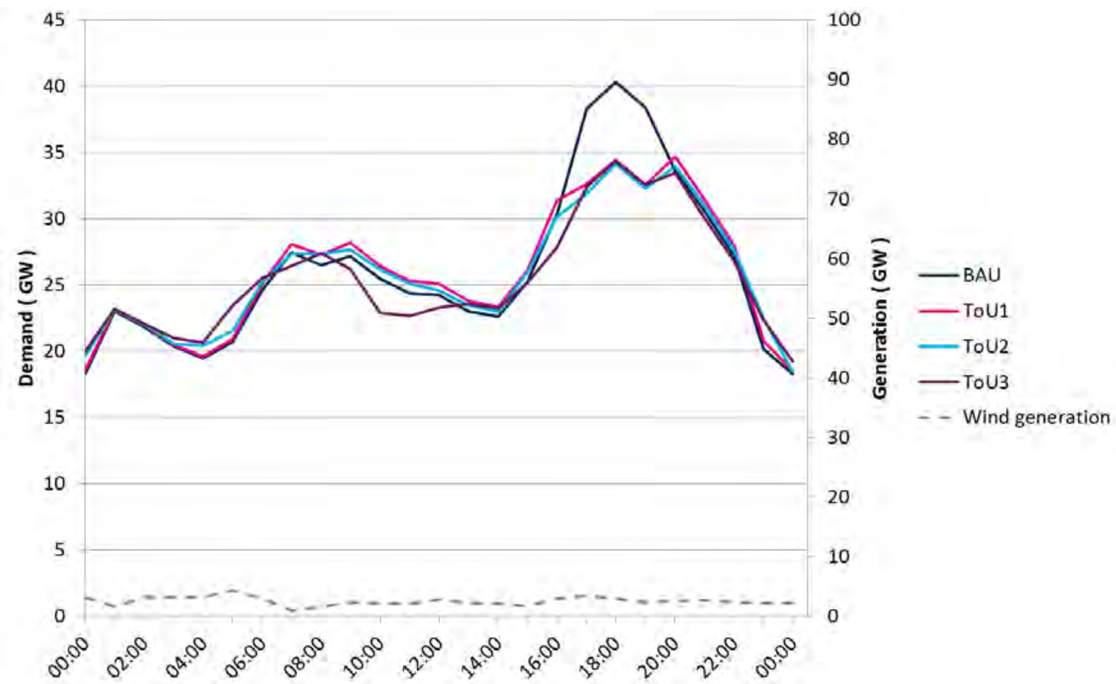
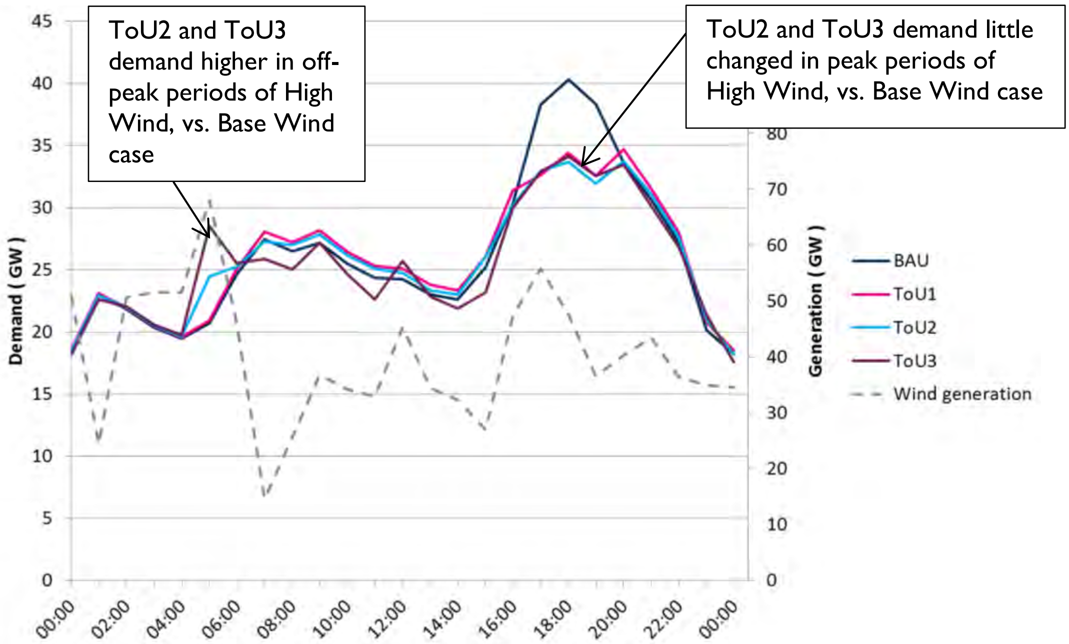


Figure 24 shows the Domestic demand profile with the High Wind case. The implied load factor is 90% in this case, which is the highest conceivable across a geographically distributed wind generation portfolio. It can be seen that in offpeak periods of high wind (5am) the demand on dynamic tariffs is higher than in the Base Wind case. The differences are of a similar magnitude to potential reductions in peak demand shown in the core results, and so it might be concluded that high wind can cancel out any peak reduction savings from dynamic tariffs. However, high wind in peak periods (5pm) does not in this example result in a significant shift in flexible demand versus the Base Wind case. This is for two reasons; first, because during winter days heat pumps have a high load, including over the peak period, and so a lower storage capacity as a fraction of load, reducing their flexibility to shift in response to price signals driven by high wind; second, due to high demand levels the impact of higher wind output during peak times on price is likely to be much less significant than offpeak.

Figure 24 - Typical winter day, 2031 Central flexibility scenario, High Wind



The sensitivity above shows that flexible load does follow wind to some degree, although the effect appears to be confined to off-peak periods, and so does not counter the reductions in peak demand seen under ToU tariffs. Further, there is insufficient flexible demand on dynamic tariffs to create a new peak in demand in traditionally off-peak periods. It should be noted that the relationship between peak demand and wind generation is key to this effect, and may be different to the scenario presented here. In the Central flexibility scenario used as the base for this sensitivity, peak demand growth is high due to the uptake of heat pumps. Should the peak demand growth be slower, or wind capacity growth stronger than assumed then the effect of wind on flexible demand will be greater.

In this analysis we have not considered the impact on local networks of pockets of flexible demand on dynamic tariffs responding to low market prices. Whilst at a national level the analysis suggests that it is unlikely that new demand peaks will be created by ToU tariffs, it is very likely that local network constraints will be created.

5 Conclusions

The objective of the analysis was to assess the potential extent of peak demand reduction, delivered through permanent demand reduction and demand shifting, related to ToU offerings from suppliers over the RIIO-ED1 and ED2 periods – from 2015 to 2031. The results were analysed separately for the Domestic and SME sectors.

The combination of uptake of LCTs (i.e. heat pumps and electric vehicles) and smart appliances, and the penetration of ToU tariffs and the consumer responsiveness to these, are key drivers for modifying the peak electricity demand and for impacting overall system demand.

Our analysis shows that peak demand reduction may differ between the Domestic and SME sectors and that the impact of each ToU case on peak demand reduction increases over time.

Permanent demand reduction

Based on evidence from the trials, we have assumed a 2% permanent reduction in consumption from Domestic customers on ToU tariffs prior to any demand shifting, associated with greater awareness of electricity consumption. No permanent demand reduction was assumed for the SME sector, since there was little evidence from the trials to suggest reduction in usage from customers on ToU tariffs.

System peak demand shifting

Our modelling shows that limited peak demand shifting is expected to occur before 2020, with relatively low penetration of ToU tariffs. However, the impact of ToU tariffs on the peak demand becomes material by 2025 and significant by 2031.

Table 17 summarises the total peak demand reduction, including shifting, in GW across the ToU cases for each period analysed.

Table 17- System peak demand reduction by ToU case (in GW)

ToU tariffs	2015	2020	2025	2031
ToU1	0	0	0 - 2.2	(0.1) - 4
ToU2	0	(0.1) - (0.2)	0.1 - 2.2	0.1 - 6.7
ToU3	0	0	0.5 - 1.9	0.8 - 7.1

With the ranges denoting the spread across the flexibility scenarios.

The ToU1 case provides the lowest peak demand reduction, with no demand shifting in the Low flexibility scenario. The biggest peak demand reduction of up to 2.2 GW occurs in the ToU2 and ToU3 cases. This would represent a reduction in peak demand of approximately 3%.

In any flexibility scenario (Low/Central/High) in 2031, the ToU3 case provides the biggest peak demand reduction, up to 7.1 GW in the High flexibility scenario, or 8% of peak demand. We observe a small negative peak reduction by -0.1 GW with ToU1 case, since in this case the impact of the limited demand shifting taking place is simply to move the peak rather than reduce it.

Domestic peak demand shifting

For the Domestic sector, no peak demand shifting is expected to occur in 2015 and we notice a limited peak demand reduction in 2020. This can be explained by the low uptake assumptions of LCT and ToU tariffs and low responsiveness assumptions of consumers.

Table 18 - Domestic peak demand reduction by ToU case (in GW)

ToU tariffs	2015	2020	2025	2031
ToU1	0	0.4 - 0.5	0.7 – 2.4	1.5 – 2.4
ToU2	0	0.4 - 0.5	0.9 – 3.3	1.7 – 5.1
ToU3	0	0.3	1 – 3.1	2 – 7.9

With the ranges denoting the spread across the flexibility scenarios.

By 2025 the impact is more significant. For example, under the ToU2 case and High flexibility scenario peak demand reduction is 3.3 GW or 12% of peak Domestic demand (27.8 GW). The lowest outcome is 0.7 GW which occurs under the ToU1 case and Low flexibility scenario.

By 2031, the modelling suggests the peak load reductoin from Domestic customers could reach 7.9 GW or 18% of peak Domestic demand. It should be noted that this reduction in Domestic peak demand exceeds the system level reduction, since some of the shifted load leads to increased demand in other periods.

SME peak demand shifting

The modelling highlights that there is limited potential for peak demand reduction from the SME sector. All ToU cases modelled show a limited decrease of the peak demand explained by a low rate of responsiveness of SMEs which consider it is not possible to move usage to other times (based on trials review).

A Redpoint GB Reference case

Redpoint/Baringa Partners produces a bi-annual GB market report, which provides a comprehensive overview of the GB power market. Our market reports are widely regarded and respected across the energy industry, both within GB and throughout Europe. We deploy state of the art modelling tools to analyse the market and produce future wholesale power price forecasts, including the application of a leading-edge market modelling tool, PLEXOS. Our model inputs include forward looking price projections for wholesale commodity prices, with input assumptions based on various established sources (e.g. IEA's World Energy Outlook, DECC, HM Treasury), ensuring that our reports are transparent and in-line with market consensus views. In the near-term, new generation capacity assumptions are based on the most recent market knowledge, regularly updated by our team of energy professionals who are working closely with developers, investors, lenders, utilities, consumers, Government and regulators. Longer term capacity assumptions are determined such that security of supply is maintained while the UK moves towards meeting its emissions and renewables targets. Our modelling also takes into consideration the implementation of a complex array of Government policies, including the introduction of a Capacity Mechanism, Contracts for Difference and a Carbon Price Floor.

Our GB modelling suite combines policy analysis, generation and transmission investment analysis, hour to hour market dispatch and the detailed modelling of the electricity network.

The figures below show details of the commodity assumptions and capacity assumptions contained in the April 2013 updated of the Redpoint GB Reference case, full details given in our GB market report.

Figure 25 - Ref Case Oil

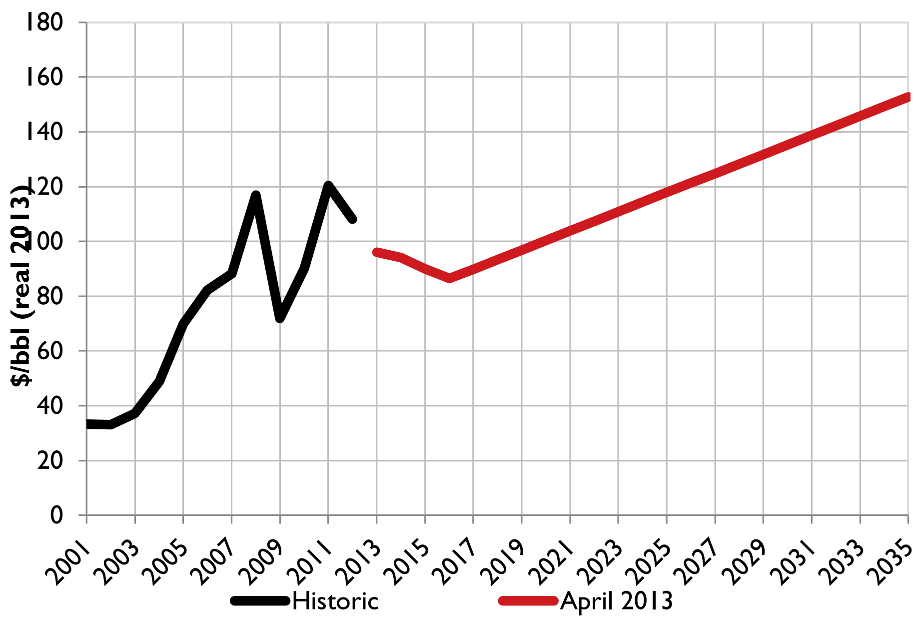


Figure 26 - Ref Case Gas

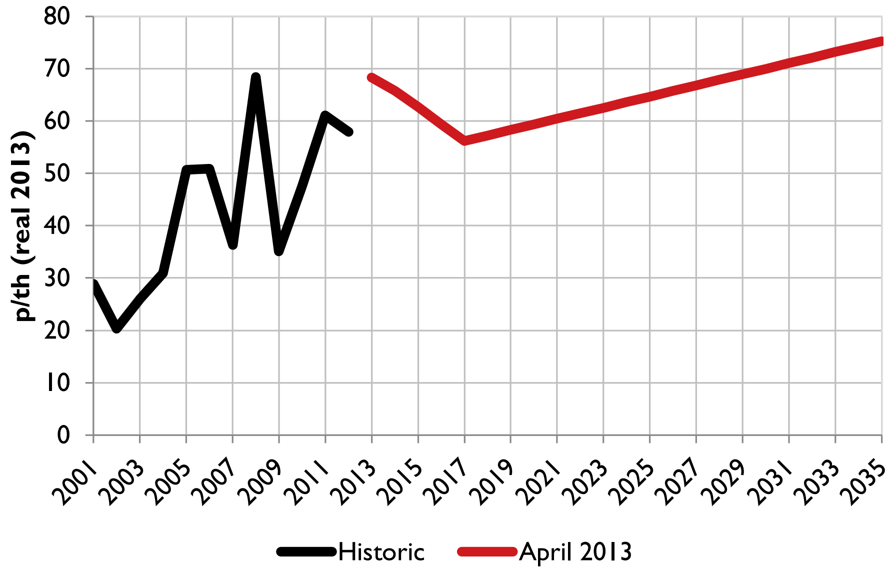


Figure 27 - Ref Case Coal

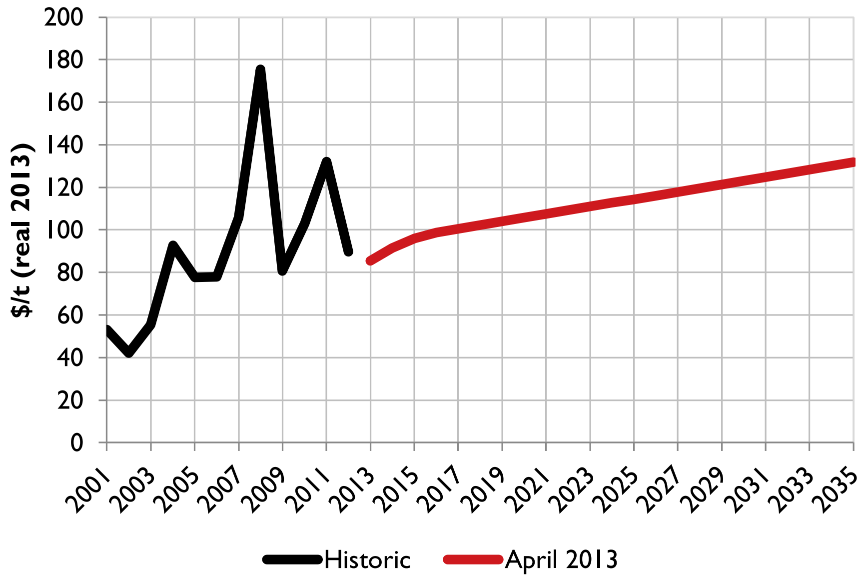


Figure 28 - Ref Case Carbon

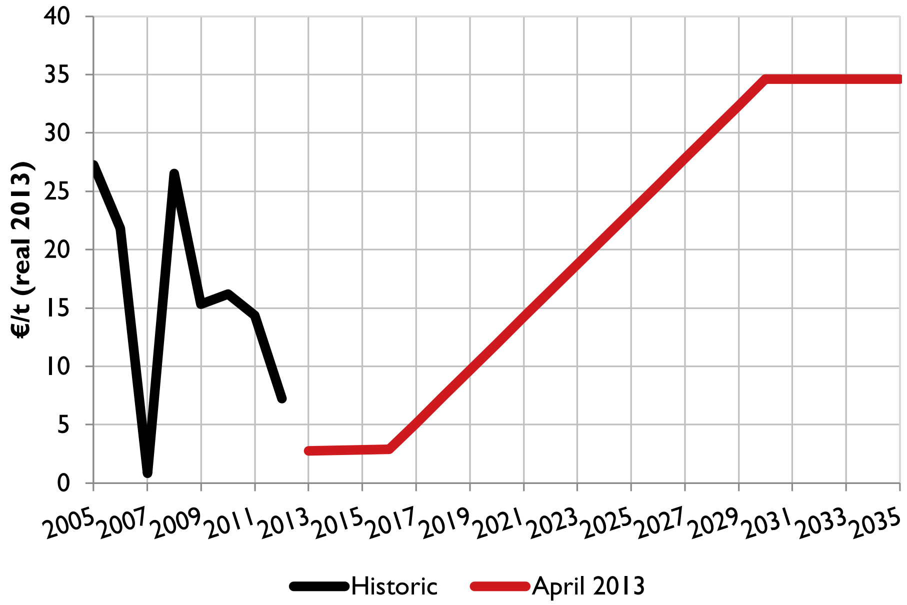


Figure 29 - Ref Case cumulative plant retirements

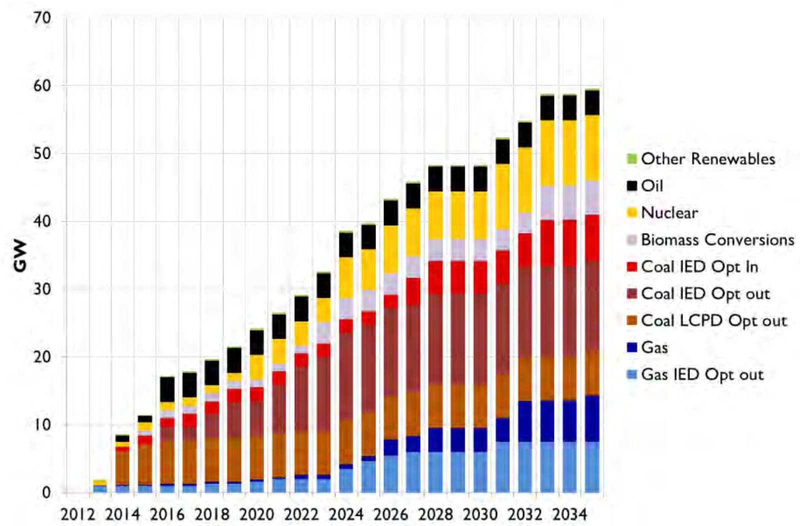
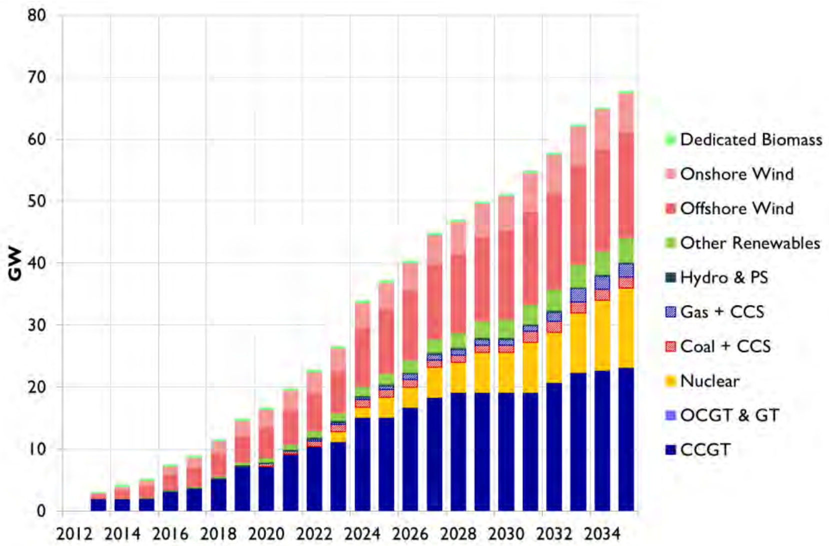


Figure 30 - Ref Case cumulative new build



B Review of ToU trials and analysis of the customer behaviour

A review of several trials has been performed in order to assess the impact of Time of Use Tariffs on consumer responsiveness.

Table 19 below provides the key results for the trials analysed for the purpose of this analysis.

Table 19 - Review of trials characteristics

Trial	Demand side response form	Sector	Peak Load impact – shifting of the peak load	Decrease of overall consumption (total consumption associated with the ToU tariff rate)	Feedback – communication sent to the customers on a regular basis	Elasticity of substitution (explained below the table)	Price elasticity (explained below the table)
CL&P* (USA)	SToU	Domestic	-3%	-	No feedback	0.05	0
	CPP	Domestic	-16%*	-	No feedback	0.08	-0.03
	CPP + Control of technology (Load Control)	Domestic	-23%*	-	No feedback	0.13	-
PSE&G* (USA)	SToU	Domestic	-5%	-	No feedback	-	-
	CPP	Domestic	-22%*	-	No feedback	0.07	-
	CPP + Control of technology (Programmable communicating technologies)	Domestic	-31%*	-	No feedback	0.13	-
CER (Ireland)	ToU	Domestic	-8.8% Customers with an in-home display showed increased load management resulting in a peak shift of 11.3% (2.5% greater than average)	-2.5%	• Standard billing (+smart meter) • Enhanced billing • Real time Feedback	-	-
	ToU	SME	-2.2%	-0.3%			
Energy Demand Research Project (UK) – EDF Energy	ToU	Domestic	0% (explained by modest peak to mid-peak price ratio)	0%	Real Time Feedback	-	-
Energy Demand Research Project	ToU via Smart Meter	Domestic	-1.5% to -2.5%	-	Real Time Feedback	-	-

(UK) – SSE							
EDF France - France	CPP (Tempo Tariff) – dynamic ToU tariff with a fixed number in any year of teach three different types of day	Domestic	- 45% - 60% during red days - 15-24% during white days (-4% of national peak) The main demand reduction on peak days came from reduced use of electric heating	-	-	-	-
Toronto Hydro - Canada	Regulated ToU	Domestic and SME	- 4- 5%	- 8%	-	-	-
Customer - Led Network Revolution (first results)	3-rate ToU	Domestic and SME	- 14%	-3%	-	-	-

* Consumer behavior observed in the US trials may not be transferable to the UK due to the climatic differences and the use of electrical loads such air conditioning loads and pool pumps. However, heat pumps can be comparable to the energy consumption of US appliances.

Notes:

- Feedback sent to customers has been assessed for some of the trials analysed. The objective was to test the influence on price response of having real-time premise-level usage provided via the web, the paper or by an in-home display.
- The Elasticity of Substitution defines the extent of substitution between energy use during high priced (peak or event) periods and energy consumed during low priced periods attributable to the pricing structure – i.e. Percentage of change in the ratio of the peak to off-peak demand as a result of percentage of change in the ratio of the peak to the off-peak price. For example, a 0.1 Elasticity of Substitution means that a 1% change in the ratio of peak to off-peak prices would lead to a 0.1% change in the ratio of off-peak to peak consumption. The convention is to report these elasticities as positive numbers.
- Price elasticity is the percentage change in electricity usage due to a 1% change in the price of electricity. A value of 'zero' corresponds to no change in usage; regardless of the change in price and absolute values progressively greater than zero indicate a relatively higher price response.
- To date, only a handful of studies estimate the overall impact on electricity consumption as a function of the change in tariffs and price elasticity, as the few results in the table above illustrates it. There is reason to be cautious in adopting the estimates of the table for use in the context of this analysis.

Economic incentives (most of them was bill savings) are effective in changing consumer responsiveness as a reduction in peak demand was achieved under the majority of the trials analysed. Customers respond particularly to:

- Time of Use Tariffs – tariffs are pre-determined and fixed in advance

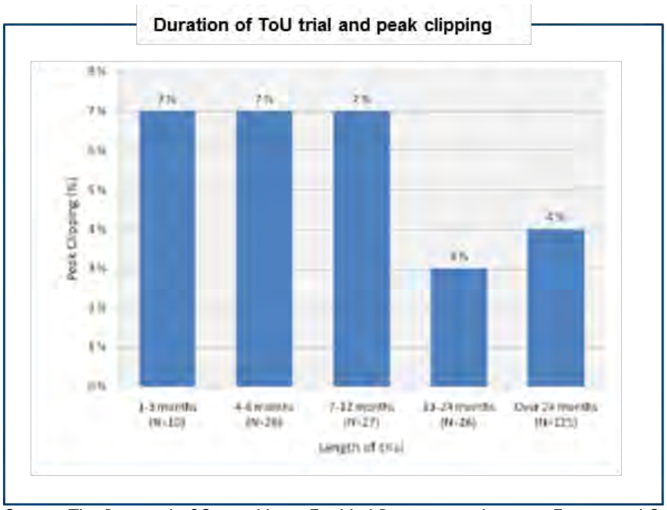
- Critical Peak Pricing - pre-determined high price during times of exceptionally high demand or 'critical peaks'

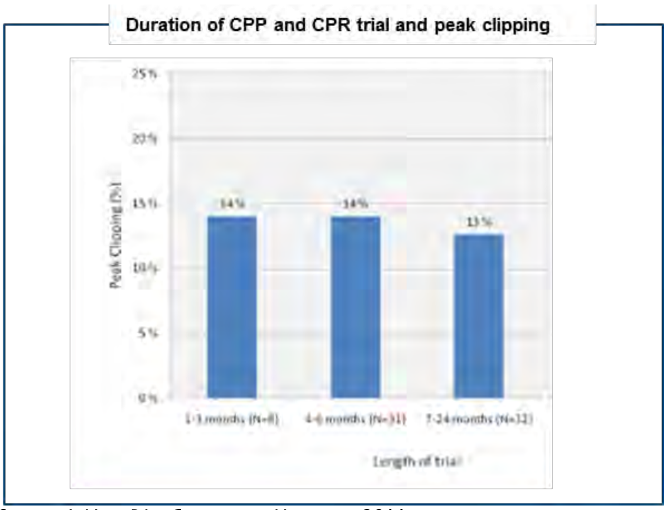
It is clear from trials that critical peak tariffs have a greater impact than SToU tariffs on peak demand on the days that the response is called. Interventions to automate responses deliver the greatest and most sustained household shifts in demand. Automation involves the application of a technology which automatically reduces electricity consumption from a given appliance during peak hours (we do not assume that Heat Pumps and Electric Vehicles will be "automated" in this way). Direct control allows appliance settings to be directly changed by the energy supplier.

The duration of the trial does not have a clear effect on the results of the pricing pilots:

- Results (based on trials analysed in the following report: The Potential of Smart Meter Enabled Programs to Increase Energy and Systems Efficiency: A Mass Pilot Comparison, Vaasa ett, 2011) in terms of peak clipping go down after 12 months but seem to be increasing again after 24 months. The reasons for this pattern are not clear as showed in the below graphs and would require additional research
- Majority of trials did last between 1 and 6 months, meaning the results were measured on one season.

Figure 31 - Sustained effect on customer behaviour





Source: The Potential of Smart Meter Enabled Programs to Increase Energy and Systems Efficiency: A Mass Pilot Comparison, Vaasa ett, 2011

However, it seems that CPP and CPR (Critical Peak Rebate - Participants are paid for the amounts that they reduce consumption below their predicted consumption levels during critical peak hours.) impact on demand side response does not reduce with time.

The CER trial confirmed that trend and showed no evidence of a diminution of effect overall when comparing the ratio of change between first six months with that of the second six months of the trial for the Domestic sector while for the SME, the effect of ToU tariffs on customer behaviour is not sustainable.

Table 20 - Sustained effect on Domestic behaviour - CER trial

Sustained effect on Domestic behaviour – CER trial	Overall change	Peak
First 6 months	-2.6%	-8.3%
Second 6 months	-2.4%	-9.3%

Source: Electricity Smart Metering Customer Behaviour Trials Findings Report, CER, 2011

Table 21 - Sustained effect on SME behaviour - CER trial

Sustained effect on SME behaviour – CER trial	Overall change	Peak
First 6 months	-0.9%	-2.9%
Second 6 months	0.3%	-1.5%

Source: Electricity Smart Metering Customer Behaviour Trials Findings Report, CER, 2011

Regarding the feedback effectiveness sent to customers at reducing consumption, CER trials showed that a bi-monthly bill, an energy use statement and a monitoring of electricity was the most effective demand side response stimulus for electricity consumers.

Table 22 - Feedback effectiveness on Domestic consumption

Usage	All tariff groups and DSM stimuli	Demand Side Response Stimulus			
		Bi-monthly bill and energy use statement	Monthly bill and energy use statement	Bi-monthly bill and energy use statement and electricity monitor	Bi-monthly bill and energy use statement and OLR incentive
Overall	-2.5%	-1.1%	-2.7%	-3.2%	-2.9%
Peak	-8.8%	-6.9%	-8.4%	-11.3%	-8.3%

Source: Electricity Smart Metering Customer Behaviour Trials Findings Report, CER, 2011

In the context of the stimuli for SMEs, the electricity monitor and the Web access test groups are most effective at reducing energy usage.

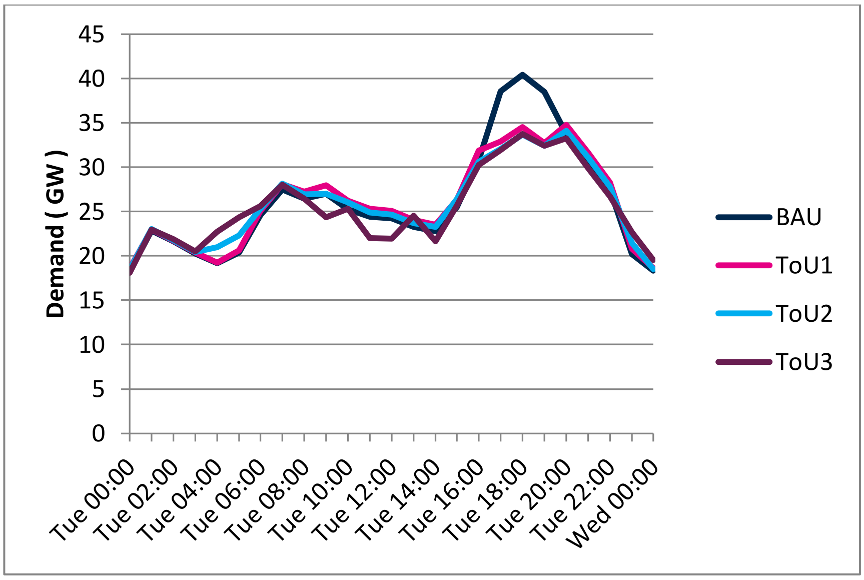
Table 23 - Feedback effectiveness on SME consumption

Usage	All tariff groups and DSM stimuli	Demand Side Response Stimulus			
		Bi-monthly bill and energy use statement	Monthly bill and energy use statement	Bi-monthly bill and energy use statement and electricity monitor	Bi-monthly bill and energy use statement web access
Overall	-0.3%	1.2%	-0.1%	-1.1%	-2.9%
Peak	-2.2%	0.0%	-4.7%	-0.6%	-5.2%

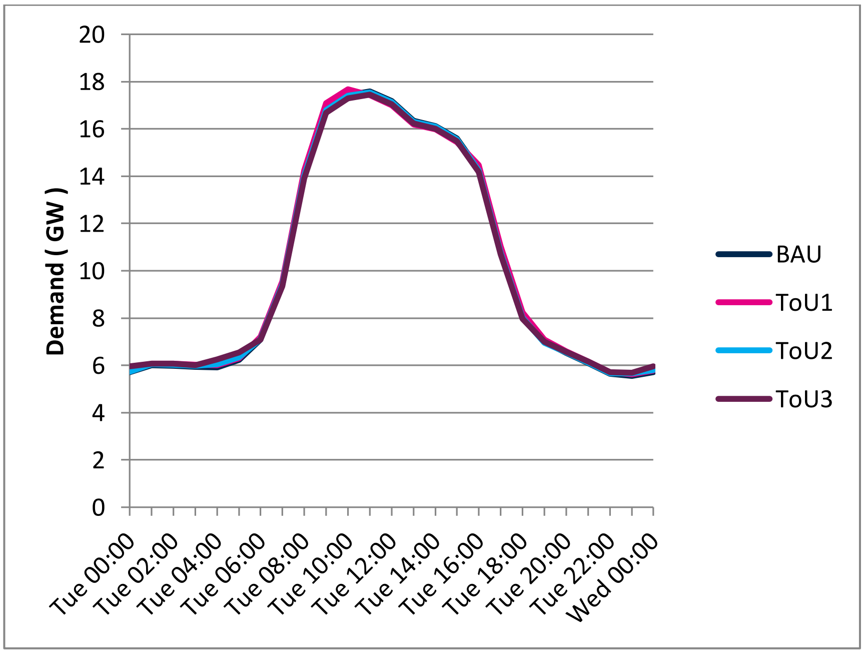
Source: Electricity Smart Metering Customer Behaviour Trials Findings Report, CER, 2011

C Appendix – Additional modelling results

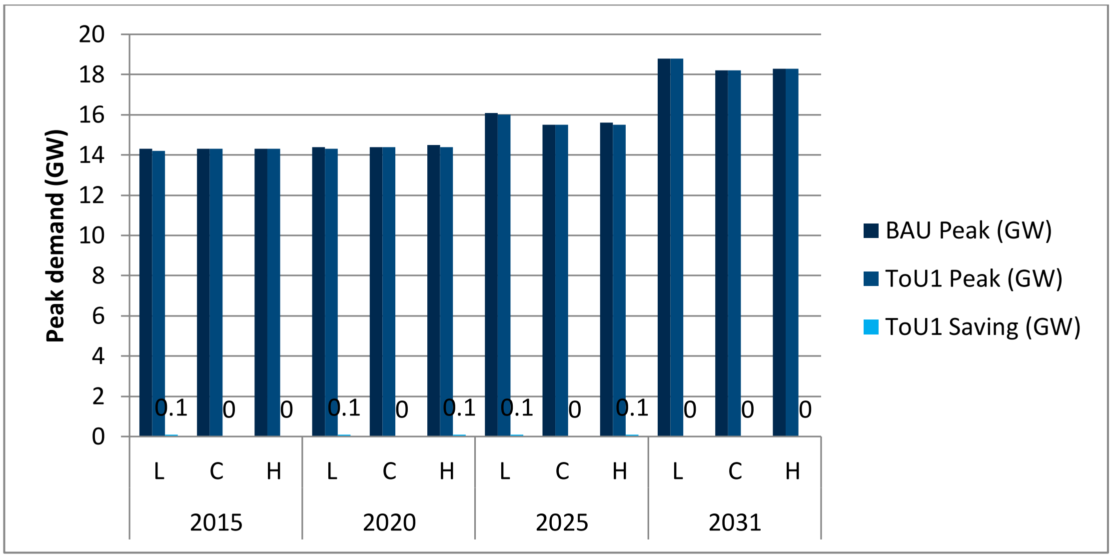
C.1 Domestic electricity demand for a typical peak day in 2031 (Central scenario)



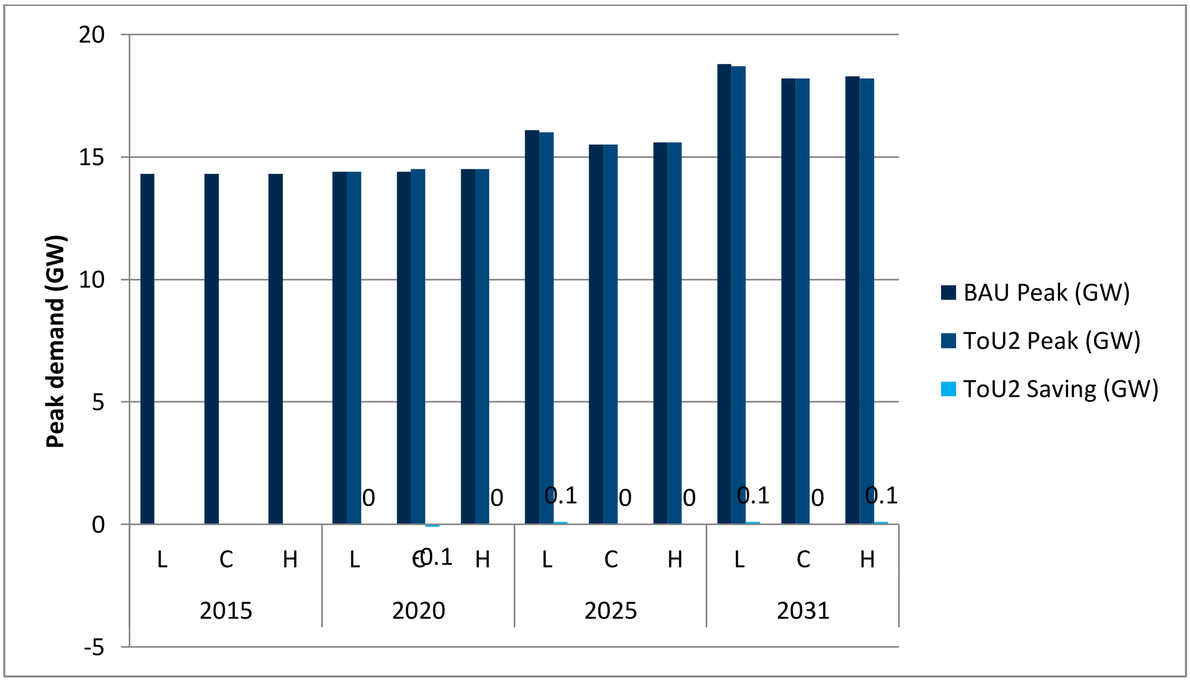
C.2 SME electricity demand for a typical peak day in 2031 (Central scenario)



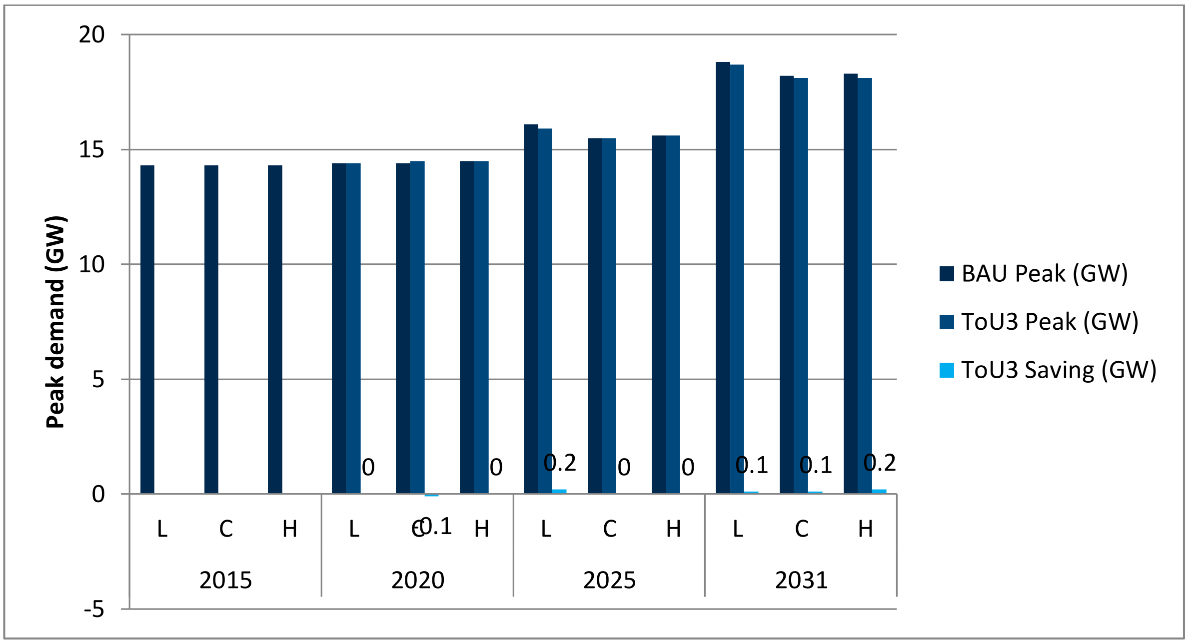
C.3 Impact of ToU1 case on SME Peak demand



C.4 Impact of ToU2 case on SME Peak demand



C.5 Impact of ToU3 case on SME Peak demand



C.6 Peak load reduction in GW by flexibility scenario and ToU case

Domestic

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	0.0	0.0	0.0	0.0
L	ToU1	0.0	0.4	0.7	1.5
L	ToU2		0.4	0.9	1.7
L	ToU3		0.3	1.0	2.0
C	BAU	0.0	0.0	0.0	0.0
C	ToU1	0.0	0.5	2.2	2.4
C	ToU2		0.5	2.6	4.0
C	ToU3		0.3	2.7	6.6
H	BAU	0.0	0.0	0.0	0.0
H	ToU1	0.0	0.5	2.4	2.1
H	ToU2		0.5	3.3	5.1
H	ToU3		0.3	3.1	7.9

SME

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	0.0	0.0	0.0	0.0
L	ToU1	0.0	0.1	0.0	0.0
L	ToU2		0.0	0.0	0.1
L	ToU3		0.0	0.1	0.1
C	BAU	0.0	0.0	0.0	0.0
C	ToU1	0.0	0.1	0.1	0.0
C	ToU2		0.0	0.0	0.0
C	ToU3		0.0	0.0	0.1
H	BAU	0.0	0.0	0.0	0.0
H	ToU1	0.0	0.1	0.1	0.0
H	ToU2		0.0	0.0	0.1
H	ToU3		0.0	0.0	0.1

System

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	0.0	0.0	0.0	0.0
L	ToU1	0.0	0.0	0.0	-0.1
L	ToU2		-0.1	0.1	0.1
L	ToU3		0.0	0.5	0.8
C	BAU	0.0	0.0	0.0	0.0
C	ToU1	0.0	0.0	2.0	3.6
C	ToU2		-0.1	2.1	5.2
C	ToU3		0.0	1.9	5.9
H	BAU	0.0	0.0	0.0	0.0
H	ToU1	0.0	0.0	2.2	4.0
H	ToU2		-0.2	2.2	6.7
H	ToU3		0.0	1.9	7.1

C.7 Peak demand in GW by flexibility scenario and ToU case

Domestic

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	22.0	22.9	23.7	31.4

L	ToU1	22.0	22.6	23.0	29.8
L	ToU2		22.6	22.8	29.6
L	ToU3		22.7	22.7	29.3
C	BAU	22.0	23.3	27.0	41.0
C	ToU1	22.0	22.8	24.8	38.6
C	ToU2		22.8	24.3	37.0
C	ToU3		23.0	24.3	34.4
H	BAU	22.1	23.4	27.8	44.4
H	ToU1	22.0	22.9	25.3	42.3
H	ToU2		22.9	24.5	39.2
H	ToU3		23.1	24.7	36.5

SME

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	14.3	14.4	16.1	18.8
L	ToU1	14.2	14.3	16.0	18.8
L	ToU2		14.4	16.0	18.7
L	ToU3		14.4	15.9	18.7
C	BAU	14.3	14.4	15.5	18.2
C	ToU1	14.3	14.4	15.5	18.2
C	ToU2		14.5	15.5	18.2
C	ToU3		14.5	15.5	18.1
H	BAU	14.3	14.5	15.6	18.3
H	ToU1	14.3	14.4	15.5	18.3
H	ToU2		14.5	15.6	18.2
H	ToU3		14.5	15.6	18.1

System

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	57.2	58.4	61.9	74.0
L	ToU1	57.2	58.3	61.8	74.1
L	ToU2		58.4	61.8	73.9
L	ToU3		58.4	61.4	73.2
C	BAU	57.2	58.5	65.0	83.9
C	ToU1	57.2	58.5	63.1	80.3

C	ToU2		58.7	62.9	78.7
C	ToU3		58.6	63.1	78.0
H	BAU	57.2	58.6	65.8	87.2
H	ToU1	57.2	58.6	63.6	83.2
H	ToU2		58.8	63.6	80.5
H	ToU3		58.6	63.9	80.1

C.8 System peak reduction compared to BAU peak demand in percentage

Flexibility scenario	ToU case	2015	2020	2025	2031
L	BAU	0.0	0%	0%	0%
	ToU1	0.0	0%	0%	0%
	ToU2		0%	0%	0%
	ToU3		0%	1%	1%
C	BAU	0.0	0%	0%	0%
	ToU1	0.0	0%	3%	4%
	ToU2		0%	3%	6%
	ToU3		0%	3%	7%
H	BAU	0.0	0%	0%	0%
	ToU1	0.0	0%	3%	5%
	ToU2		0%	3%	8%
	ToU3		0%	3%	9%

D Appendix – glossary of terms

Term	Definition
CPP	Critical Peak Pricing. Option which allows the supplier to call a limited number of events during pre-specified time periods based on short-term system conditions (called events), high costs, or both. Participants pay a much higher (critical peak) price for all usage during the event hours
DECC	Department for Energy and Climate Change. A centralised government department formed in October 2008 by merging parts of the Department for Environment, Food and Rural Affairs (DEFRA) and Department for Business, Enterprise and Regulatory Reform (BERR) to oversee energy and climate in a consistent manner.
DNO	Distribution Network Operator. Operator of a regional low voltage electricity distribution network.
DSR	Demand Side Response. The ability of an electricity consumer to reduce load in periods of high price.
DLC	Direct Load Control. Measure which allows suppliers and customers to have direct control on certain loads, providing the opportunity to switch loads off during peak periods or increase demands at times of excess generation.
Ofgem	Office of Gas and Electricity Markets. The regulator ensuring a fair and proportionate market.
RIIO	Revenues = Investment + Innovation + Outputs. The regulator's model for price controls.
SToU	Static Time Of Use. Customers are charged different rates depending on the time of day that they use the commodity. Electricity meter has at least 2 registers, and switches between the 2 based on the time.
ToU	Time of Use. Associated with tariffs which differ according to when energy is consumed.

Review of Analysis of Network Benefits from Smart Meter Message Flows

(Including RIIO ED1 and ED2 phasing and categorisation of benefits)

1st July 2013

Version 1.0

Review of Analysis of Network Benefits from Smart Meter Message Flows

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Tables

1.0 Background

In March 2012, ENA undertook an analysis of potential benefits from smart meter message flows in order to:

- Answer a number of specific questions from DECC's Smart Metering Implementation Programme Team relating to previously documented smart meter message flows – specifically DECC's 'Analysis of network benefits from smart meter message flows: Data Request Table' issued on 7 March 2012; and
- Provide an overall present value benefits analysis to support the case for specific aspects of smart meter functionality – in particular functionality that would facilitate the management of electricity distribution networks.

This review of benefits should be read in conjunction with the ENA March 2012 paper; the document can be downloaded from the ENA website here.

Prior to publication, the final draft of the March 2012 paper was circulated to all DNOs seeking endorsement. Unqualified endorsement was received from 4 DNOs; qualified endorsement was received from SSE. WPD felt unable to endorse the analysis due to concerns over the inherent level of uncertainty regarding quantification of benefits.

The March 2012 analysis necessarily incorporated numerous assumptions regarding future pressures on electricity distribution networks, particularly those relating to low carbon technologies and also regarding the potential to mitigate such pressures through influencing the quantum and shape of future electricity demand patterns which would for example depend on Suppliers introducing appropriate incentives through time of use (ToU) tariffs. Such assumptions were informed, in the broadest sense, by DECC's indicative 4th Carbon budget scenarios for low carbon technologies but no detailed analysis of prospective residential or SME property load shape was undertaken at that time.

The analysis also drew on the earlier published ENA / SEDG / Imperial College paper (Goron Strbac et al) - 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks' - which can also be downloaded from the ENA website here.

The March 2012 paper identified numerous categories of potential benefits and in each case quantified these benefits in present value terms taking account of assumed take-up rates of low carbon technologies and the timing of availability of required smart metering volumes and functionality. The overall DCF study considered the period from 2015 to 2030 but took account of when benefits from the smart meter rollout would start to become available and the longevity of the benefit in each case (the rationale for assumed longevity of benefit is described in section 6 of the report). An overall potential present value of benefits of £1.292b was derived from the analysis. These benefits, if realised, would accrue to consumers in terms of:

- Avoided network investment, principally at the LV and 11kV network levels (consistent with the ENA / SEDG / Imperial College paper)[1];
- Reduced levels of LV and 11kV network losses (compared with a non-smart counterfactual) the costs (and hence benefits) of which would ultimately fall on (to) consumers; and
- In the case of quality of service benefits (which are relatively small in monetary terms), an assumed value based on customer willingness to pay data.

From the March 2012 analysis it is clear that the increase in electrical energy distributed by networks, and the future daily load shape of residential and SME demand, will both be critical factors in determining the

[1] note: no consideration was given to potential overlap with non-load related investment

reinforcement pressures that electricity distribution networks will in future be subjected to as a result of low carbon transition.

The March 2012 paper demonstrated that an ability to influence (either purely through tariff price incentives, or a combination of price incentives, smart appliances and direct load control) *could* have a major beneficial impact on peak demand driven reinforcement at LV and 11kV (including 11kV/LV transformation) levels[2]. Similarly, peak smoothing (improving load factor) *could* have a major beneficial impact in terms of reduced variable losses. These two (related) benefit streams account for £1.004b of the £1.292b overall present value of benefits.

A smaller, albeit still important, contribution to managing future peak demands identified by the analysis was that of Active Network Management (undertaken solely by DNOs but informed / enabled by smart meter data / functionality[3]); the March 2012 study, looking out to 2030, derived savings with a present value of £136m.

2.0 Benefits in Context

It should be emphasised that whilst the March 2012 analysis derived a present value of benefits as a component of an overall cost-benefits analysis, it did not in itself constitute a cost-benefits analysis since at that time the incremental costs of providing the necessary supporting functionality within the overall smart metering system (including the data management and communications systems) were unclear. Neither did the analysis seek to quantify the costs of providing or enhancing DNOs' data management systems (including systems for aggregating hh consumption data). Nevertheless, should the derived present value of benefits of £1.292b (approx. £46 per meter) prove feasible, it would seem likely that a positive NPV of benefits (net of costs) could be derived, at least for some components of smart meter functionality.

It is also important to understand the context of the study which was to evaluate those network benefits that *could* be leveraged from the smart meter programme under ideal market conditions and regulatory frameworks, assuming that all parties (including Suppliers and/or potential intermediaries, and not least consumers) are incentivised to behave 'logically' (for example in terms of developing (Suppliers) and responding to (consumers) time-of-use tariffs).

In particular, it should be noted that by far the majority of the financial benefit is delivered through actions to shift demand from peak and/or improve load factor (reducing peak relative to average demand) which in turn enables lower costs associated with network reinforcement and losses. In order that network losses are fully valued, these were considered from a 'whole system' perspective (i.e. the whole system costs – including generation – of supplying network losses and incorporating a value ascribed to carbon) and valued at £60 per MWh in line with the proposed DPCR5 incentive rate[4]. This is important in supporting the business case for smart meter functionality, since ultimately it is consumers who will fund the costs of smart metering and hence should benefit from savings in such 'whole system' costs.

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[2] It is important to note that the study did not assume the above benefits to be dependent on DNOs alone providing (DUoS) price signals and/or exercising control over demand; rather it assumed that consumers and/or smart appliances would control demand and that synergies in benefits between Suppliers and DNOs would, at least under most weather/demand scenarios, lead to complementary energy and DUoS time-of-use price signals

[3] For example: network load balancing, phase balancing, power factor control, and active voltage control

[4] Ofgem subsequently took the decision not to activate the incentive for DPCR5

3.0 Scope of Review

The purpose of this paper is to take stock of developments since the March 2012 paper (in particular with regard to SMETS2 functionality and the smart metering system security architecture) and provide a revised update of the deliverability of the benefits indicated by the March 2012 paper.

The primary focus for the review is the derivation and quantification of those benefits which will impact DNOs' cost bases. This is of particular importance to the RIIO ED1 Business Plans which DNOs will submit to Ofgem in July 2013. Hence the evaluation is in terms of ED1 and ED2 period benefits and expressed as real, non-discounted values rather than in present value terms.

This paper draws on work recently commissioned by ENA with EA Technology Ltd (EATL), KEMA and Baringa Redpoint who were requested to revisit the derivation and quantum of the benefits detailed in the March 2012 paper. This latest review incorporates all information and analyses that has become available since the publication of the March 2012 paper; in particular:

- The more detailed analysis now available from DECC in terms of 4th Carbon Budget scenarios (including projections for renewable DG technologies provided in February 2013);
- The more detailed analysis of future residential and SME load shape undertaken as part of the derivation of the Smart Grid Forum WS3 Transform Model;
- The conclusions drawn from the Smart Grid Forum WS3 Transform Model in terms of required levels of network investment over the ED1 and ED2 periods under DECC's 4th Carbon Budget scenarios; and
- The implicit effects of the recession in reducing present demand levels and hence reducing the need for reinforcement expenditure in many parts of GB at the current time[5] (albeit the possible effects of recovery in terms of 'catch-up' should not be dismissed);

Certain network benefits are heavily dependent on parties other than DNOs for their delivery (in particular Suppliers and consumers); it is not within the gift of DNOs to enforce Suppliers to introduce ToU tariff incentives which would encourage peak demand shifting, nor do the restrictions on DNOs in terms of transmitting 'critical' messages (such as load control actions) over the DCC network enable DNOs to directly undertake load control actions.

Whilst the benefits are those associated with improved efficiency of distribution network operation and investment, not all of these benefits will be reflected in savings in DNOs' costs (or increases in DNOs' incomes or incentives). For example, customer service benefits, such as faster response to LV faults, are simply a monetised value ascribed to such benefits based on assumed 'customer willingness to pay' criteria[6]. Similarly, network losses savings (the single most significant benefit identified in the March 2012 paper) would accrue to DNOs only to the extent that an appropriately valued regulatory losses incentive was in place. As with DPCR5, no target-based losses incentive (such as that put in place for DPCR4) is planned for ED1[7]. And whilst savings in reinforcement investment were taken as actual avoided costs, no IQI sharing of benefits (between DNOs and consumers) has been assumed; rather the implicit assumption is that these investment avoidance benefits are fully incorporated within DNOs ED1 business plan submissions.

[5] 'Implicit' because it is assumed that DNOs' proposed ED1 and ED2 levels of 11kV and LV general and connections-driven network reinforcement will reflect this effect

[6] Albeit in practice there would also be a small IIS benefit which would accrue directly to DNOs

[7] Notwithstanding Ofgem's proposed licence condition and £32m discretionary reward

Benefits that are no longer deliverable are identified and separated from those which (albeit dependent on other parties) remain achievable. For example, the current version of SMETS2 precludes the possibility of delivering the 'extreme voltage protection' benefit (as the functionality is excluded) and the minimum IHD functionality does not support remote messaging.

Whilst the monetised benefits in the March 2012 paper were presented in present value terms based on a 3.5% p.a. real discount rate (and taking account of when benefits would be expected to begin to flow; when some benefits might cease; and the variation over time of the quantum of certain benefits) these were not presented in terms of in-period benefits – i.e. ED1 and ED2. In order to inform DNOs' 'well justified business plans' following the further guidance now published by Ofgem's March 2013 Strategy Paper, this latest review also provides an indication of the anticipated apportionment of benefits, in real (i.e. neither inflated nor discounted) terms, over the ED1 and ED2 periods[8].

4.0 Summary of Further Research

In order to try and quantify the monetary benefits accruing to DNOs' cost bases through Smart Meter technologies, EATL, KEMA and Baringa Redpoint were commissioned to undertake a review of the March 2012 ENA paper and an interim review of this paper produced by the ENA in March 2013. They were requested to re-examine and update the benefit assumptions and to include any additional areas that may have been omitted from the earlier work.

- EATL's work concentrated on the network investment benefits arising from the use of Smart Meter data and in particular from various levels of customer response to ToU tariffs. Their report can be found here.

- KEMA were requested to examine the spectrum of benefits including network faults, design processes, connections processes, reinforcement costs and active network management. Their report can be found here.

- Baringa Redpoint were requested to focus on the likely behaviour of Suppliers during the ED1 and ED2 periods and in particular the likely strength, format and benefits of ToU tariffs. Their report can be found here.

5.0 Summary of Findings

KEMA and EATL each considered specified aspects of the benefits identified in the March 2012 report, reviewed the assumptions, and methodology and, where appropriate, applied their own assumptions and methodologies to form their view of benefits. Whilst Baringa Redpoint were not asked to review the value of the benefits, their analysis has been helpful in terms of the level of confidence that can be attributed to consumers' responsiveness to ToU tariffs and the resulting impact on peak demand.

[8] In the case of DSR-related benefits and network losses, such apportionment is extremely sensitive to assumptions regarding the take up rates of electric vehicles and heat pumps over the ED1 and ED2 periods

Baring Redpoint and EATL have applied different approaches in their assessment of impact of ToU tariffs on peak demand and their respective results are not directly comparable. However, both indicate a material reduction in peak demand over the ED2 period but a much smaller benefit over ED1.

In most cases KEMA and EATL's assessment of benefits is broadly consistent with those in the ENA March 2012 paper with one notable exception relating to the losses benefit.

The assessment of the losses benefit in the ENA March 2012 paper was based on a number of assumptions relating to the increase in demand from Low Carbon Technologies, the proportion of overall losses occurring on DNO low voltage networks and the proportion of the potential 'load flattening' benefits identified in the Imperial College work that could be achieved in practice.

The assessment of the losses benefit assessed by EATL was derived from the Transform model and would have used different, albeit related, assumptions. These assumptions have resulted in a reduced level of peak load shifting associated with ToU tariffs and consequently lower losses benefit (network variable losses are proportional to the square of the current, so the effect of a reduced level of peak demand shifting is magnified).

The most material assumptions when assessing the losses benefit are those relating to the extent to which Suppliers introduce ToU tariffs and the response of consumers to them.

Whilst the difference in assessed losses benefit is material when compared with the other benefits this different needs to be set into context against the total GB losses value and their associated cost. Current GB losses are in the region of 17.5TWh pa which at £60/MWh equates to £1050m pa or £8400m in an eight year ED1 period (assuming no appreciable increase in network utilisation factors and no decrement to daily load factor over the eight year period).

However, by 2030, under DECC's 4th Carbon Budget scenarios, electricity consumption could increase by as much as 19% compared with today due to electric vehicle and heat pump load. It follows that, especially taking account of the fact that network copper (variable) losses are proportional to the square of the current, a reasonable assumption is that distribution network losses could increase by as much as 7.5TWh pa (42%) to 25TWh pa by 2030, i.e. £1500m pa or in the region of £10,000m over an eight year period ED2 (the aggregate value over eight years will depend on the ramp-up rate over this period).

Taking ENA's March 2012 saved losses benefit evaluation of £100m over ED1, at £60 per MWh this equates to a saving of 1.7TWh or just 1.2% of the estimated distribution network losses over the ED1 period.

It follows that even under ENA's original evaluation, the assessed network losses benefit in ED1 and ED2 is relatively small when compared against the total cost of losses. The much smaller range of assessed network losses benefit in ED1 and ED2 as assessed by EATL is therefore extremely small when compared against the total cost of losses.

Whilst the Baringa report does not comment on the impact on network losses of ToU tariffs, their modelling does show a significant reduction in winter peak day demand (around 5GW at the system level, and up to 7.9GW of domestic peak demand in 2031 compared with the BaU case) under all of their ToU scenarios. Further analysis by ENA indicates that a peak demand reduction of this magnitude (and even allowing for an equivalent level of demand to occur at off-peak times such that the overall level of energy consumed is constant) could result in a reduction in variable losses of around 3.5%[9]

Given the large number of uncertainties particularly with the rate of demand growth associated with Low Carbon Technologies and DG growth, the phasing of the Smart Meter roll out plans and the response of consumers, it was not considered practicable to focus on a single benefit value per benefit category. Instead, a likely range of benefits was derived from the work of the consultants and the earlier work by ENA members.

These results are presented below and disaggregated into 4 categories:

- Benefits impacting on DNOs' cost bases which are deliverable by DNOs independently of other parties;
- Benefits impacting on DNOs' cost bases which are dependent on the actions of Suppliers and consumers in particular relating to the introduction of and response to ToU tariffs;
- Benefits that do not impact on DNOs' cost bases; and.
- Benefits no longer available due to limitations in smart metering equipment specifications (or security architecture).

Each category of benefits is separately shown for the ED1 and ED2 periods and presented in real, non-discounted terms[10].

A brief description of the derivation of each benefit is provided. However, for a complete understanding, reference should be made to the papers detailed above.

It will be noted that, in general, the benefits are skewed towards the ED2 period reflecting both the anticipated completion of the smart meter rollout programme (end of 2020) and, more significantly, the anticipated growth trends for low carbon technologies such as heat pumps and electric vehicles, and hence the benefits of managing such demand away from peak periods.

6.0 Overall ED1 Summary

- The benefits attainable by DNO action and directly impacting DNOs' cost bases should be within the range £35m- £54m.
- The Baringa and EATL work shows that load shaping via Supplier ToU tariffs has a marginal benefit to DNOs' cost bases in ED1 but a much greater, but uncertain, benefit in ED2. In ED1 ToU tariffs are likely to confer a further £12m - £26m benefit to DNOs' cost bases.
- The total benetit impacting DNOs' costs bases should be within a range of £47m to £80m.

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[9] This is based on peak reduction at the system level and assumes network resistance remains constant (i.e. no difference in network capacity) under both the ToU and BaU scenarios. A 7.9% reduction in peaks demand at the HV/LV network level would result in even greater reductions in losses at this level.

[10] except where otherwise stated

- Losses benefits (which do not accrue to DNOs' cost bases) are significantly reduced when compared with the ENA March 2012 report due to the lower EATL and Baringa assessments of the load shaping opportunity via Supplier ToU tariffs and lower demand levels than originally anticipated.
- £24m of benefits previously available to the DNO will not be available as a result of further development of SMETS2.

The following tables compare the values of benefits as assessed by ENA in March 2012 with those now assessed by KEMA and EATL.

(i) Benefits deliverable by DNOs independently of other parties (based on SMETS2 functionality)

		ENA	ENA	KEMA	KEMA		Benefit impacting on DNO cost base in ED1 in DNO control		Benefit impacting on DNO cost base in ED2 in DNO control	
Category	**Nature of Benefit**	**ED1 Period Benefit (£m)**	**ED2 Period Benefit (£m)**	**ED1 Period Benefit (£m)**	**ED2 Period Benefit (£m)**	**Notes**	**Min (£m)**	**Max (£m)**	**Min (£m)**	**Max (£m)**
1. Proactive Planning of HV & LV networks	Better informed load-related investment decisions	17.6	13.2	11.4	27.5	From 2019-2025 only - then superseded by Responsive Demand and ANM benefits	11.4	17.6	13.2	27.5
2. Voltage monitoring and sag/swell alarms	Avoided voltage complaints and admin costs	2.7	5.5	2.7**	5.5**	Assume gradual increasing trend from 2015 to 2020 due to increasing smart meter volumes and from 2025 due to faster LCT ramp rate and full smart meter coverage	2.7	2.7	5.5	5.5
3. Proactive Planning of HV & LV networks	Reduced investment to serve new connections	13.8	10.4	13	31.5	From 2019-2025 only - then superseded by Responsive Demand and ANM benefits	13	13.8	10.4	31.5
4. Power Outage Management	Reduce duration of LV interruptions	27.2	36.2	14.1	24.1	Increasing from 2015 to 2019 (when rollout complete). ENA benefit is based purely on consumer willingness to pay (WTP) value of 0.17p per minute and assumes no DNO incentive benefit or opex saving KEMA benefit is based on Ofgem's RIIO ED1 value of lost load (VOLL) i.e. 0.107p per minute and again assumes no DNO incentive benefit or opex saving	(Do not impact on DNO cost base)		(Do not impact on DNO cost base)	
5. Power Outage Management	Reduced Guaranteed Standard failure payments	2	4	2.1	3.6	From 2019 assuming energisation status polling capability Note: proposed ED1 reduction from 18h to 12h not taken into account	2	2.1	3.6	4
6. Active Network Management	Optimising LV network voltage and power flows informed by smart meter data	17.4	118.5	6 to 8*	6 to 221*	Based on LCT exponential growth trend and minimum cost of counterfactual in the IC report (assuming 10% increase in capacity headroom) Assumes hh 'real time' data flows from smart meters	6	17.4	118.5	221
min total		80.7	187.8	49.3	98.2					
max total		80.7	187.8	51.3	313.2		35.1	53.6	151.2	290

NOTES:

ENA values are those presented in the March 2012 report presented as undiscounted values aggregated for the ED1 and ED2 period.

Benefits are based on a 2014 mass roll out commencement rather than the new 2015 mass roll out, so the ED1 benefits will be reduced if new timing is applied.

*All the ENA and KEMA values are undiscounted values apart from these as the base figures KEMA used were provided to them by EATL as discounted values.

**ENA values used as figures not provided by KEMA for these items.

The two dark green columns on the right show the range of monetary benefit for those items that impact DNOs' cost bases. Note that the nominal QOS improvements do not confer a DNO IIS benefit as outage start and finish times advance by the same amount. There is a notional benefit associated with open circuit faults, but it's so small as to be negligible.

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(ii) DSR benefits dependent upon Supplier-led ToU tariffs and load control / smart appliances

		ENA	ENA	EATL	EATL		Benefit impacting on DNO cost base in ED1 outside DNO control		Benefit impacting on DNO cost base in ED2 outside DNO control	
Category	**Nature of Benefit**	**ED1 Period Benefit (£m)**	**ED2 Period Benefit (£m)**	**ED1 Period Benefit (£m)**	**ED2 Period Benefit (£m)**	**Notes**	**Min (£m)**	**Max (£m)**	**Min (£m)**	**Max (£m)**
7a. Responsive Demand - TOU tariffs	Reduced need for network capacity to meet peak demand	26.1	177.7	12.0 to 119.0	94.1 to 348.4	Based on LCT growth in the various 4th carbon budget scenarios and taking outputs from Transform for the two scenarios giving the extreme figures. For this analysis, no distinction has been drawn between response to ToU incentives and use of smart appliances, as discussed in the report	12	26.1	94.1	177.7 (7a. only)
7b. Responsive Demand - Load Control	Remote control or smart appliance managed responsive demand	34.8	236.9							
8. Management of Network Losses	Mitigated increase in variable I2R network losses due to improved load factor	100.8	685.7	4.9 to 7.6	55.1 to 66.4	Based on DECC 4th carbon budget scenarios 3 and 4 assuming losses valued at £60 per MWh (DR5) Note £100.8 equates to 1.7TWh saving over ED1; £685.7 equates to 11.4 TWh saving over ED2. Benefits from losses reduction do not accrue to DNOs (no target based losses incentive in ED1)	(Do not impact DNO cost bases)		(Do not impact DNO cost bases)	

min total		161.7	1100.3	16.9	149.2
max total		161.7	1100.3	126.6	414.8

Responsive Demand benefit ranges above are those that DNOs have determined to be the best estimate after consideration of all he factors available and taking into account the high degree of uncertainty.

NOTES:

ENA values are those presented in the March 2012 report presented as undiscounted values aggregated for the ED1 and ED2 period.

Benefits are based on a 2014 mass roll out commencement rather than the new 2015 mass roll out, so the ED1 benefits will be reduced if new timing is applied.

(iii) Total DNO cost-base impacting benefits (Summary of tables (i) and (ii))

Category	Nature of Benefit	RIIO ED1 Period DNO cost-base impacting benefits (in DNO control) Min (£m)	RIIO ED1 Period Max (£m)	RIIO ED2 Period DNO cost-base impacting benefits (in DNO control) Min (£m)	RIIO ED2 Period Max (£m)
1. Proactive Planning of HV & LV networks	Better informed load-related investment decisions	11.4	17.6	13.2	27.5
2. Voltage monitoring and sag/swell alarms	Avoided voltage complaints and admin costs	2.7	2.7	5.5	5.5
3. Proactive Planning of HV & LV networks	Reduced investment to serve new connections	13	13.8	10.4	31.5
5. Power Outage Management	Reduced Guaranteed Standard failure payments	2	2.1	3.6	4
6. Active Network Management	Optimising LV network voltage and power flows informed by smart meter data	6	17.4	118.5	221
7. Responsive Demand - TOU tariffs	Reduced need for network capacity to meet peak demand	12	26.1	94.1	177.7
8. Responsive Demand - Load Control	Remote control or smart appliance managed responsive demand				
Total		47.1	79.7	245.3	467.2

(iv) Benefits no longer available due to changes in the Smart Meter specification

Category	Nature of Benefit	ENA ED1 Period Benefit (£m)	ENA ED2 Period Benefit (£m)	Notes
1. Remote Messaging	Reduced postal / transport charges for notified shutdowns (from 2019)	4	8	Minimum IHD spec in SMETS2 does not support text messaging
2. Extreme Voltage Protection	Elimination of damage to consumer appliances	20	40	Assumed Floating Neutral (extreme voltage) Protection – now excluded from SMETS2
Total		24	48	

NOTE:
ENA values are those presented in the March 2012 report presented as undiscounted values aggregated for the ED1 and ED2 period.

(v) Total network related benefits from Smart Meter Message flows

Source:	ENA	ENA	EATL & KEMA	EATL & KEMA	ENA	EATL & KEMA
	Combined benefits of (i) and (ii) for ED1. (£m)	Combined benefits of (i) and (ii) for ED2. (£m)	Combined benefits of (i) and (ii) for ED1. (£m)	Combined benefits of (i) and (ii) for ED2. (£m)	Total ED1 & ED2 network benefits (£m)	Total ED1 & ED2 network benefits (£m)
min	242.4	1288.1	66.2	247.4	1530.5	313.6
max	242.4	1288.1	177.9	728	1530.5	905.9

NOTE:

ENA values are those presented in the March 2012 report presented as undiscounted values aggregated for the ED1 and ED2 period.

CONFIDENTIAL REPORT

Prepared for:
Energy Networks Association (ENA)

Reviewing Network Benefits of Smart Meter Message Flows

Workstream 2 – Benefits dependent on DSR actions by Suppliers and Consumers

Authors: M Sprawson & D Yellen

Report No: 85580

Project No: 85580

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Draft 1.0	04/04/13	M Sprawson		Early draft issued to DNV-KEMA to ensure consistency
Draft 2.0	05/04/13	M Sprawson	D A Roberts 05/04/13	Includes additional material: losses calculations and conclusions
Draft 2.1	15/04/13	M Sprawson & D Yellen		Revised following comments from ENA members
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Draft 2.3	19/04/13	M Sprawson & D Yellen		Final draft incorporating minor modification after comments from ENA members
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Executive Summary

The main conclusions that can be drawn from the analysis contained in this report are as follows:

1. Based on data from National Grid, demand levels are expected to reduce steadily initially (until around 2019) given the increases in energy efficiency and low initial movement towards electrification of heat and/or transport.

2. The network reinforcement costs associated with meeting the demands placed on the network by LCTs are low in RIIO-ED1 but increase rapidly and significantly in ED2. The costs associated with meeting these demands are very similar for three of the DECC scenarios, with the 'Credit purchase' scenario representing an outlying, low, position.

3. Demand is likely to be reshaped if a supplier only needs to pay a customer 2p/kWh of demand moved[1]. If the required rate to be paid is nearer to 10p/kWh, the results suggest that this becomes uneconomic from a supplier perspective. Demand reshaping is more prevalent for feeders supplying largely domestic load, rather than those focused on commercial load. Although demand is reshaped significantly at 2p/kWh, the change to peak demand is still fairly minimal (normally less than 5% and in some cases, negligible). Assuming DSR can take place at a cost of 2p/kWh for a supplier, the amount of network reinforcement that is avoided varies from £9m - £85m in ED1 and from £55m - £235m in ED2 for the various scenarios. All figures given in discounted totex terms.

4. An assessment of load shaping through direct remote control of demand and/or by smart appliances responding to ToU tariffs was removed from the scope of works and has not been investigated in this report.

5. It has been shown that demand profiles could vary with different wind profiles, with peak demands moving by up to three hours and varying by up to 10%.

6. Transform estimates that the projected increase in cost of losses will be reduced through DSR actions and have been shown to save between £35m and £45m on average (on an NPV basis over the period to 2030) depending on the scenario considered (DECC 4th Carbon budget scenario 3 and Scenario 4 give the high and low bounds). Losses have been considered on individual feeders and have been shown to reduce by approximately 2% for supplier initiated DSR as against the predicted amount of losses with no DSR actions in place.

7. A review of DSR trials and customer attitudes has shown that overall customers are receptive to DSR measures, but that the level of incentive must be sufficiently high to encourage behaviour. This level is considerably higher than the 2p/kWh which is indicated by the analysis in this report to be economic for suppliers to achieve reshaping through DSR. An average demand reduction of 5% seems feasible, provided that the incentive rate is appropriately set. Response to DSR trials has shown that the most effective results are obtained in areas where some heating or cooling load (such as air conditioning) can be shifted.

[1] This analysis assumes that all of the energy suppliers are homogenous with the same blend of generation and customer types in their supply / demand portfolio. Differences between specific energy suppliers are out of scope of the GB Transform™ model, and therefore out of the scope of this report.

8. An analysis of the potential benefits of reducing peak loads by up to 10% in 2030 using DSR, projects that the total saving available up to 2030 on reduced network investment could be as high as £2 billion or as low as £35m dependent on the DECC 4th carbon budget scenario whilst savings on losses are consistently around £45m independent of scenario.

Contents

1 Introduction

1.1 Approach

The demands placed on the electricity distribution network (particularly at LV and 11kV) are likely to change dramatically over the coming years as a result of the drive towards electrification of heat and transport and to ensure delivery of governmental targets relating to carbon emissions.

The precise nature of these changes is, as yet, not fully understood, but there are likely to be a number of contributory factors that can be examined. This report addresses some of these factors, building on analysis carried out for Workstream 3 of the Smart Grid Forum over the past year. The approach taken is to consider the various elements described in the ENA document 'Scope of Works for Reviewing Network Benefits of Smart Meter Message Flows', focussing on the tasks listed under Workstream 2 of this document:

Workstream 2 Scope of works	This Report
1. Consider the impact on peak demand and load shape on DNOs networks at LV and 11kV of each of DECC's 4th Carbon Budget scenarios depicted in Annex 2. One possible option would be to utilise the detailed analysis of load shape evolution undertaken by GL Noble Denton, along with the regional forecasting of LCT growth rate undertaken by Element Energy, in order to support the development of the SGF WS3 Transform model.	**Section 2**
2. For each scenario determine and quantify (using the SGF WS3 Transform model as a reference source or otherwise) the costs of 11kV and LV network reinforcement (through conventional means or smart solutions - including enablers) necessary to accommodate the new peak demands over the ED1 and ED2 periods.	**Section 3**
3. For each scenario determine and quantify the credible extent to which load shape modification purely as a consequence of consumers responding to ToU tariffs, informed by smart meter data and enabled by smart meter functionality, could mitigate reinforcement costs and/or smart solutions in 2 above over the ED1 and ED2 periods.	**Section 4.1**
4. For each scenario determine and quantify the credible extent to which load shape modification through direct remote control of demand and/or by smart appliances responding to price signals, and enabled by smart meter functionality, could further mitigate reinforcement costs and/or smart solutions in 3 above over the ED1 and ED2 periods.	**Section 4.2**
5. Evaluate and quantify the extent to which 'beneficial' load reshaping under 3 and 4 might be mitigated or even undermined by load shaping to follow national wind generation output over the ED1 and ED2 periods.	**Section 4.3**
6. Based on the residual position determined by 5, estimate (in MWh terms) the extent to which the increase in distribution network variable losses under 1 above would be mitigated over the ED1 and ED2 periods through load shape modification (clearly stating underlying assumptions).	**Section 4.4**
7. Undertake high-level benchmarking of experience in other countries that have rolled out smart metering and peak demand shifting strategies to determine whether the evidence supports the conclusions of this Workstream in terms of the extent to which peak demand can be shifted in practice.	**Section 5**

In this way, the changes to demands both on a nationwide and local feeder basis, brought about through the connection of low carbon technologies are examined. The anticipated costs of meeting these increased demands, under a range of scenarios and adopting a range of solutions can then be considered. An additional factor to consider is the likely effects of time-of-use tariffs being introduced by electricity suppliers. While these are not yet fully understood, it is possible to model potential effects by considering a range of costs associated with demand shifting and analysing the extent to which demand is shifted at such prices. In doing this, it should be noted that it is assumed there is no cost to DNOs associated with demand shifting, and all DSR is being conducted via supplier time of use incentives.

In order to complete this analysis, use is made of the Transform™ model developed by EA Technology with support from the following partners: GL Noble Denton, Element Energy, Frontier Economics, Chiltern Power, Smarter Grid Solutions and Grid Scientific with regard to various inputs, such as demand profiles, feeder composition, enabler costs, etc. This allows demand profiles to be examined on a half-hourly basis for peak demands each year between now and the end of RIIO-ED2 to establish how these demands will alter and how they may be influenced by supplier incentives. Considering these factors, together with anticipated reinforcement costs to mitigate growth in demand, can contribute to an overall assessment of the benefits of smart meters to network operators. In assessing the scope for DSR in this study, only DSR activity driven by suppliers looking to manage generation costs has been considered. This may result in network benefits to DNOs if the time from which demand is shifted coincides with local network peaks. There may be additional benefits to network operators if they were to engage in DNO-led DSR; but such considerations are outside the scope of this study.

Furthermore, in modelling the requirement for demand shifting, the Transform™ model creates a priority order for demand shifting, as follows: Heat Pumps with storage, EV charging, smart appliances. In all the model runs shown in the following sections the demand shifting has been achieved entirely through the use of demand shifting of Heat Pumps with storage. This means that more demand shifting potential is available but is not justified in terms of reducing generation costs. It could however be justified in terms of reducing network investment costs (were DNOs to lead certain DSR activity) but this has not been modelled.

1.2 Assumptions

In order to ensure that all work is aligned with the ongoing work under Phase 3 of Workstream 3 of the Smart Grid Forum, all key modelling assumptions within Transform™ will be held constant, and consistent with that piece of work.

It should be noted that these assumptions do not necessarily concur with any assumptions used in previous work not making use of Transform carried out by or for ENA with regard to a benefits analysis of smart meter message flows with regard to distribution networks.

The key assumptions that will be used are as follows:

1. All 4 DECC scenarios will be considered in terms of:
    a. Distributed Generation uptake
    b. Electric Vehicle uptake
    c. Heat pump uptake
2. Energy efficiency will be held at 'Policy' level throughout all scenarios and all study cases
3. Underlying load growth is taken from National Grid figures
4. A discount rate of 3.5% will be used for all present value calculations
5. The rate of incentive for ToU DSR will be 2p/kWh unless otherwise stated
6. The model will use a look ahead period of 5 years when selecting investments and will aim to achieve a minimum of 1% of headroom being available after this 5 year period
7. The assumed temperature for winter peak conditions is -3°C and for winter average is 0°C
8. When analysing individual feeders, Cluster Group 4 is taken as default unless otherwise stated. This is the fifth most highly clustered group and represents approximately 12.5% of feeders on the network. This group is felt to be appropriate as the cluster levels are not too high so as to overstate the need for investment, but are still high enough that clustering has an effect (at the very low cluster groups there is little to no clustering present).
9. All modelling will use the national GB model of Transform v3.2.0 (released March 2013) and all associated parameters relating to costs of conventional and smart solutions and enabling technologies

In this way, all outputs are expected to be wholly consistent with Phase 3 of Workstream 3 of SGF, allowing for direct comparisons to be made with other reports produced under that project.

2 Impact on peak demand and load shape

This analysis focuses on the way in which load is changing as a result of the connection of low carbon technologies to the distribution network, and does not include any load reshaping through DSR actions. Throughout the report all charts are based on the winter peak condition and show the likely demand over a 24 hour period on a cold winter's day.

It should be noted that demand reduces between 2012 and 2020. This is because energy efficiency measures are taking effect and the uptake levels of low carbon technology are only very low in the initial period and then, in some scenarios, increase rapidly through the latter portion of RIIO-ED1 and more markedly through ED2.

2.1 Local feeder demand

In order to consider how demand may change at a more local level, three of the available 19 LV feeders have been identified for analysis: LV1 (Central Business District (CBD)), LV8 (terraced street) and LV9 (rural village fed via overhead network). All feeders are radial rather than meshed. The reason for selecting these three feeders is that it gives an interesting cross section of different types of network present within a DNO licence area, with LV1 clearly being dominated by commercial load, while the other feeders have a domestic bias. The inclusion of a rural network allows for a reasonable proportion of electric heating demand to be considered, which is only present to a much smaller degree within the terraced street environment.

Of the 19 LV feeder types contained within Transform, the terraced street feeder is the most common, accounting for over 34% of all GB feeders. The CBD radial feeder accounts for just under 2% and the rural village feeder for approximately 2.5% of the population.

In each case, the analysis has used cluster group 4 within Transform, to act as a representative level of clustering rather than overstating the potential load change or indeed assuming even distribution of low carbon technologies across feeders.

There is a high degree of correlation between the first three scenarios. Therefore, in order to improve readability, the graphs for the 'high abatement in heat' and 'high abatement in transport' scenarios are omitted from this section and only the 'high electrification of heat and transport' and 'credit purchase' scenarios are shown. These reflect the two extreme ends of the spectrum of scenarios.

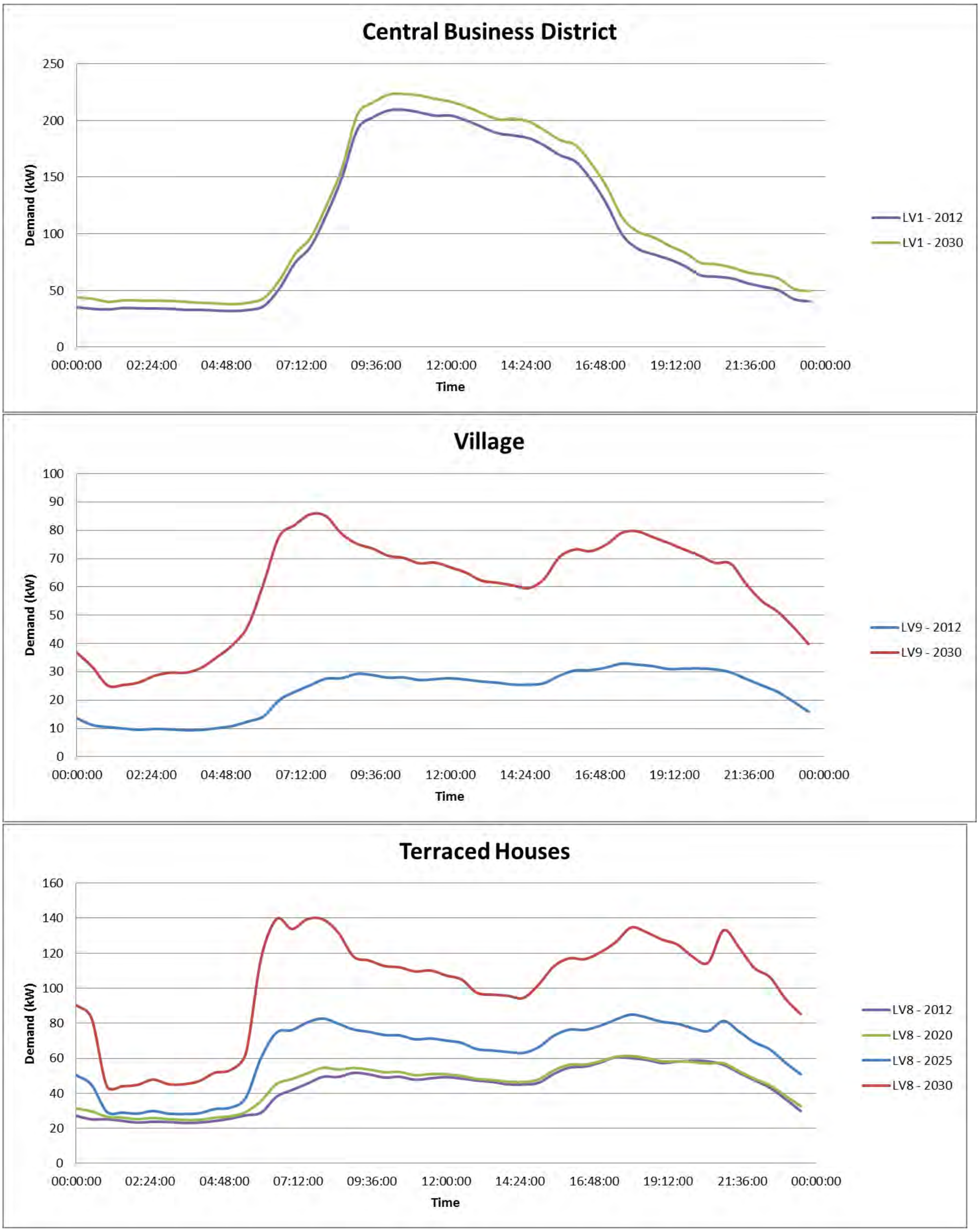


Figure 1 Daily demand for winter peak condition across three representative feeders for 'high electrification of heat and transport' scenario

It can be noted from Figure 1 that in the case of the CBD feeder, there is very little increase in demand between 2012 and 2030. This is as a result of the demand being commercial and not being allocated a great deal of heat pump or electric vehicle load, while still receiving the benefits of some PV generation and energy efficiency measures.

The increase for LV8 and LV9 is much more substantial as heat pumps and electric vehicles are present to a far greater extent. The graph for the terraced street feeder (LV8) has further been expanded to show how demand increases at 2020 and 2025 to draw out the fact that a large amount of the change in demand actually happens in RIIO-ED2 (and indeed, the latter half of ED2).

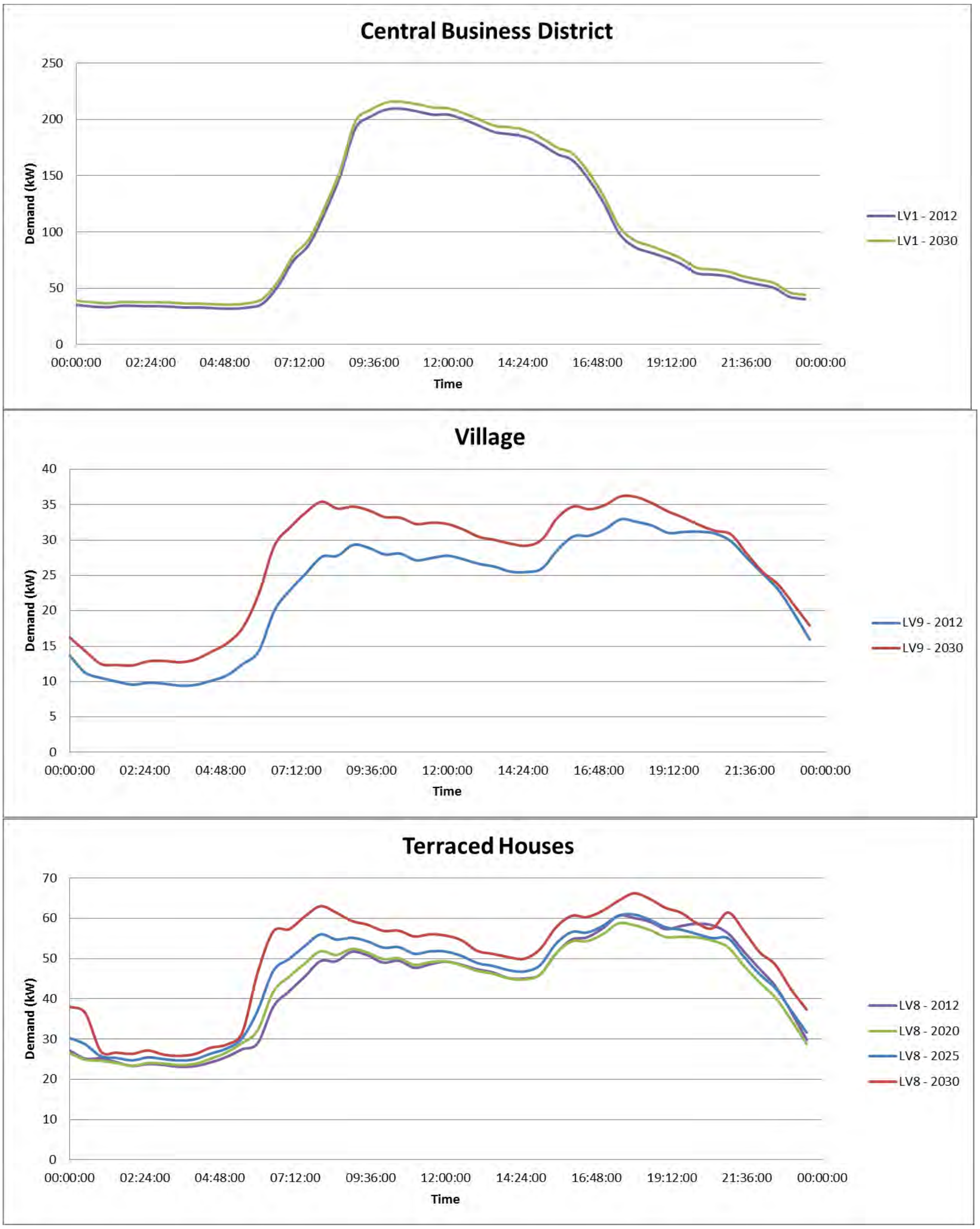


Figure 2 Daily demand for winter peak condition across three representative feeders for 'credit purchase' scenario

There is a clear difference between Figure 2 and Figure 1 insofar as the level of demand increase for each feeder in the 'credit purchase' scenario is significantly reduced. This demonstrates that the level of heat pump uptake, say, in rural settings under this low scenario is unlikely to present any real problems to network operators, unless the uptake is extremely highly clustered.

3 The costs of 11kV and LV network reinforcement

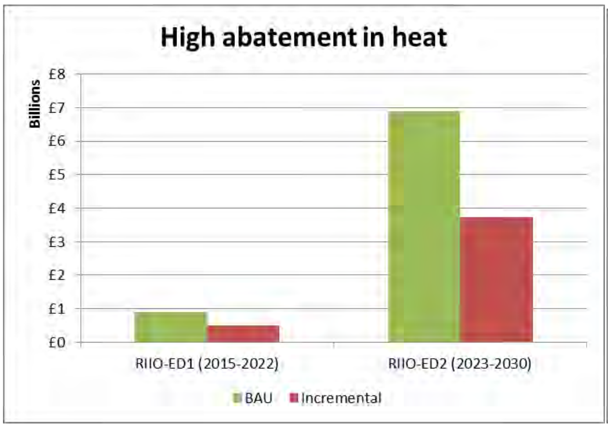
In order to meet the changing demands imposed upon the distribution network, a considerable amount of investment will be necessary. In this section, the amount of investment required during ED1 and ED2 for each of the four scenarios is presented. The Transform model has again been utilised to establish how these investment levels vary depending on whether a 'smart incremental' or conventional Business-As-Usual 'BAU' investment strategy is employed. A BAU strategy only considers conventional solutions, such as transformer and circuit replacement, whereas a smart strategy considers these solutions together with alternative options such as active network management, real time thermal ratings etc (neglecting any solutions aimed at shaping the load profile, such as domestic demand side response).

All of this analysis focuses only on investments required at the 11kV (or equivalent, such as 6.6kV, 6kV or 20kV) and LV voltage levels and deliberately excludes any investment at 33kV and above.

In all cases, the investment requirements are presented as discounted totex, with a discount rate of 3.5% having been consistently applied.

Figure 3 again highlights the similarities between three of the scenarios and clearly demonstrates the fact that the majority of investment is necessary in ED2. As would be expected, in all cases, the 'incremental smart' strategy is shown to be more cost-effective than 'BAU' and the step up from investment in ED1 to ED2 represents between a four-fold and seven-fold increase (in the incremental strategy).

The 'credit purchase' scenario by contrast shows a much more evenly split investment requirement. This, again, is in line with expectations as the numbers of LCTs connecting to the network are very small and do not see the sudden acceleration that is present in each of the other scenarios.



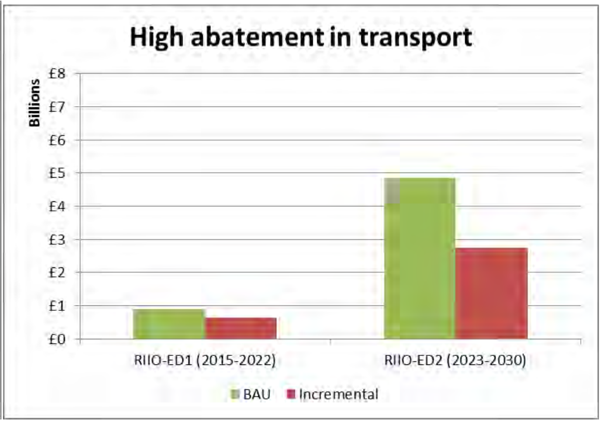


Figure 3 Investment necessary in ED1 and ED2 as a result of interventions on 11kV and LV networks to meet LCT demands

Figure 4, below, indicates the overall level of investment required at 11kV and LV until the end of ED2 for each of the four scenarios, indicating that the high electrification of heat and transport scenario does represent the most significant levels of investment, but is not vastly dissimilar (particularly when considering a smart incremental investment strategy) to the first two scenarios.

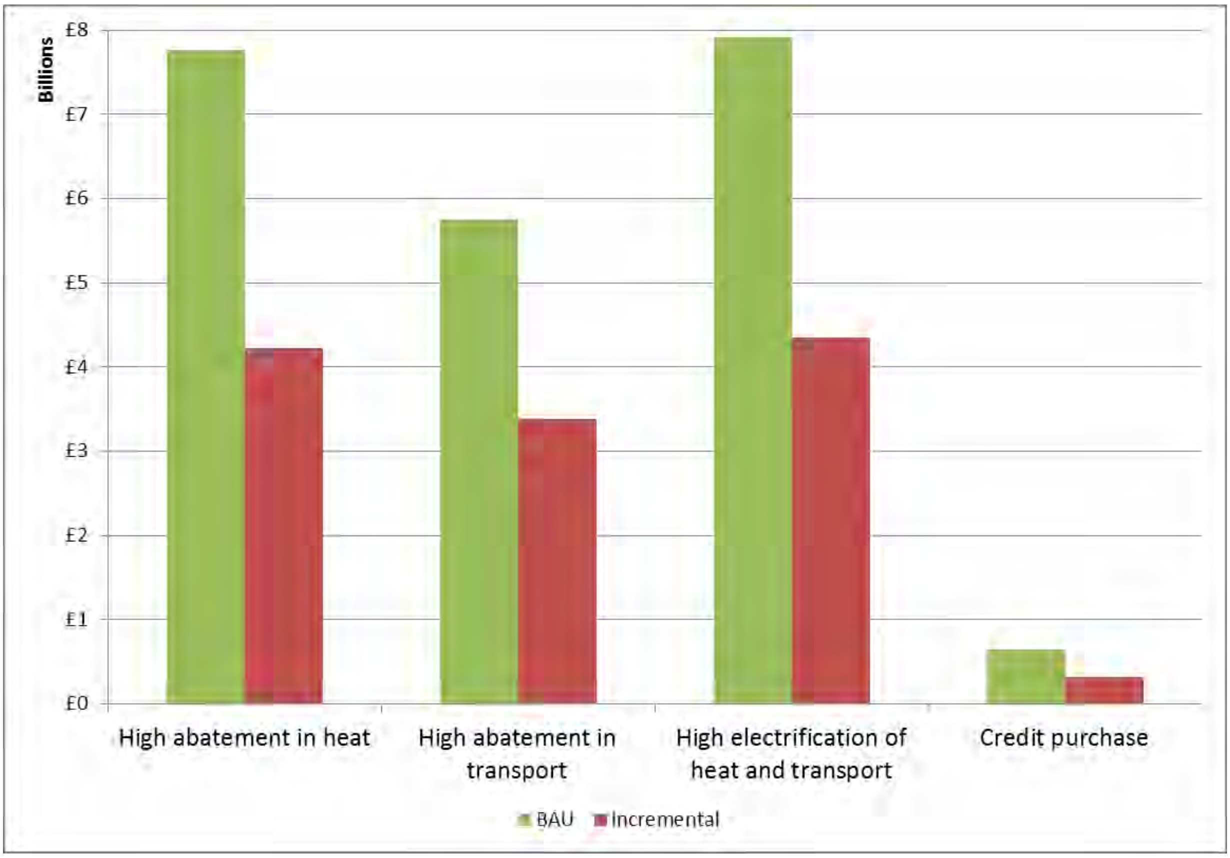


Figure 4 Total investment at 11kV and LV required before the end of RIIO-ED2 (2030) for each of the scenarios and investment strategies

4 Load reshaping through DSR

4.1 The credible extent for customer response to ToU tariffs

In order to establish the likely changes to demand profiles as customers respond to supplier-led time-of-use incentives, a series of assessments have been carried out.

It should be noted that this analysis does not attempt to quantify a customer's willingness to pay, nor does it look to determine what incentive rate should be set out by a supplier. Rather, it has considered the attractiveness to an average supplier of being able to move customer demand to meet its own needs. In order to do this, three rates per kWh of supplier to customer incentives were agreed with the project team and examined: 2p, 10p and 20p. Clearly this is a complex area and the actual impact will be governed by marginal difference between peak and off peak pricing as well as competitive tariffs attracting different consumer groups. Much more work will be required to fully analyse this situation.

It should be noted that this analysis assumes that the generation market works 'perfectly' and that all suppliers have access to the same generation portfolio. Furthermore, it also assumes that all suppliers have a homogenous customer base which is evenly distributed across the country. Clearly this is a simplification, but it is a necessary assumption in order to enable the analysis without the need to consider the complicated trading arrangements currently in place. This means that although results presented indicated that DSR at a cost of, say, 20p to a supplier is uneconomic, there may be cases across the country for certain suppliers where the reverse is true. The nature of the model is to consider a GB-wide approach and does not attempt to compensate for regional variations.

The analysis considered the GB-wide case as well as the three individual LV feeders considered previously to determine the way in which demand was likely to be altered with these incentive rates in place for the various DECC scenarios. Given time and budget constraints it was necessary to select a year to display on the graphs as an example of the amount by which a load profile has been altered and 2030 has been used in all cases. This year was selected as being the final year for full data from DECC on LCT roll out. As we move forward through time, the proportion of load that can be shifted increases (as more customers purchase smart appliances etc) and hence for the ED1 and ED2 periods, this could be considered to represent something of a 'most optimistic' case in terms of the amount of demand that would be shifted.

As stated in section 1.1, this analysis only considers supplier-led DSR through time of use incentives. It specifically does not cover any network operator-led DSR, any DSR through the use of aggregators, or any individual contracts that network operators may have established with industrial and commercial customers to manage demand.

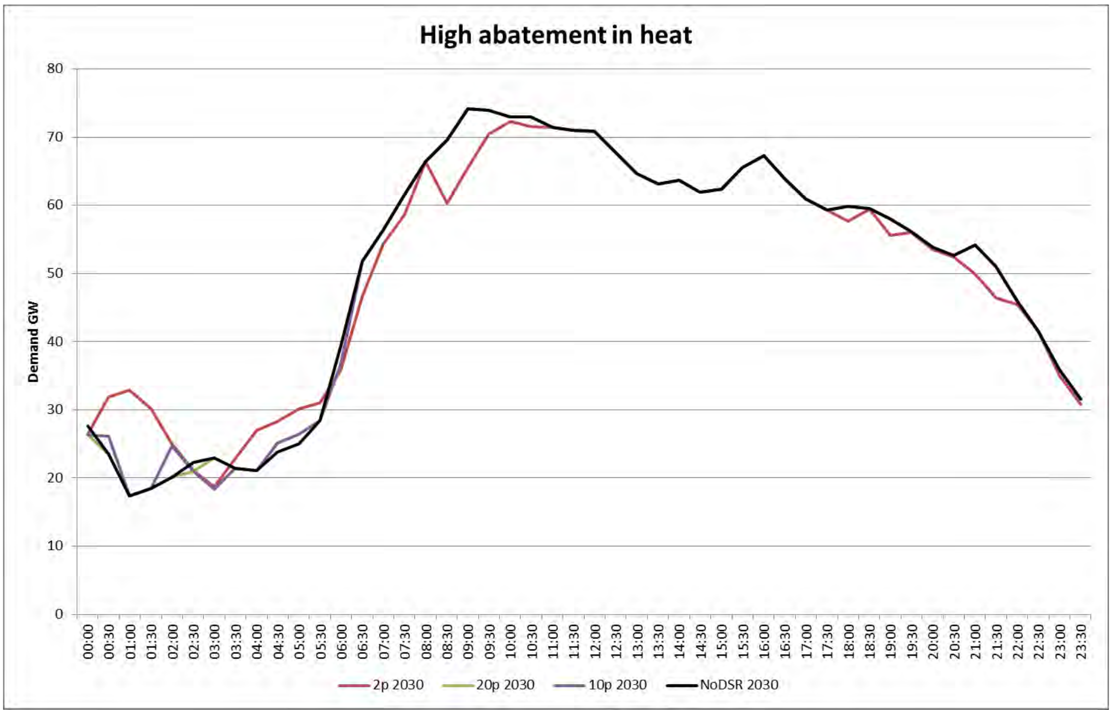
4.1.1 GB-wide case

The following graphs (Figure 5) show the winter peak daily demand in 2030 across Great Britain for each of the four scenarios. In each case, the black trace shows the demand expected to be present with no load reshaping through DSR, while the other traces show the extent to which the demand curve is altered with an incentive rate of 2p, 10p and 20p/kWh.

The curves for the first three scenarios look similar, with a peak of around 73 – 75GW, whereas the credit purchase scenario has, as would be expected, a much lower peak of just under 60GW owing to the lack of uptake of electric vehicles and heat pumps.

In all cases, there is a reasonable amount of demand shifting occurring when the incentive rate is 2p/kWh (the red trace), but at higher costs any changes are confined to the early hours of the morning. This is because as the incentive rate increases, from 2p to 10p the generation options available to save larger amounts are increasingly rarely available.

For all scenarios, the peak is reduced through the use of DSR at 2p/kWh and the extent of this reduction varies from 3GW to approximately 10GW in the case of the 'high abatement in heat' scenario. However, although this reduction occurs at time of original peak, the new peak of the red curve is only approximately 2GW below the original peak; and this is true of all scenarios, with the peak shifting by around 90 minutes.



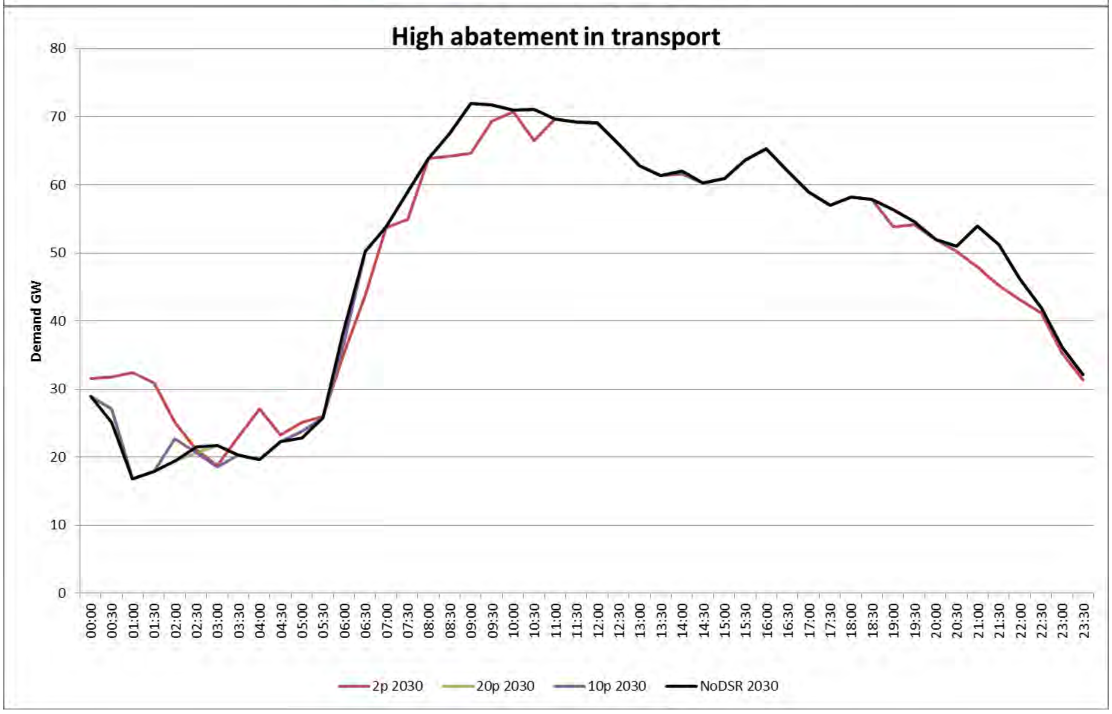


Figure 5 National demand profiles for winter peak day in 2030 with various incentive rates for DSR applied across all scenarios

Some justified concern has been expressed at the shape of these load curves, showing a morning peak. This morning peak arises from the shape of the commercial load curves currently in use in the model. Whilst these load curves are broadly in line with Elexon's commercial load curves EA Technology accept that these curves would benefit from further examination and the review of these load curves has been placed into the next WS3 Governance review (due in September 2013), providing time for considered reflection on this issue.

4.1.2 Individual feeder analysis

For ease of reading, and owing to the similarities that exist between three of the scenarios, the results presented here focus on the ‘high electrification of heat and transport’ and ‘credit purchase’ scenarios to act as boundary conditions.

It can be seen from Figure 6 that in the case of the CBD feeder, the model predicts that there is very little change to the demand profile irrespective of the cost assigned to DSR. This is because the demand found within the CBD does not lend itself so readily to DSR as that found in other settings. For example, there is unlikely to be many smart appliances that would respond and nor is there likely to be the same level of engagement as one might find from an individual consumer who could save money by using their appliances at different times of day. Conversely, there will be shiftable space heating (including heat pumps) and air conditioning loads, which are factored into the model, and this solution may still prove to have benefits for localised demand shifting.

The village feeder shows some significant variation if the national rate is 2p/kWh, but virtually none with any higher rates. The most obvious shift occurs during the mid-morning when demand is reduced and is reassigned to the overnight period. However, it should be noted that while some demand is shifted from peak periods, there are still some half-hourly periods where very little demand is shifted, meaning that the overall reduction in peak is very small.

The terraced street feeder shows the greatest variation at the 2p/kWh rate and a small variation can be seen in the early morning at higher rates (10p and 20p). The reason that more variation is seen on this feeder can be attributed to the fact that there are more domestic connections to this feeder than either of the other two, and hence the scope for shifting certain elements of demand increases. This is because only a certain proportion of each load type (such as wet appliances) are able to be shifted, but because there are more connections and hence more wet appliances supplied along this feeder, there is greater scope for demand re-shaping. It should still be noted, however, that for both the 10p and 20p rate, the level of change to demand that occurs is minimal, even with a significant amount of load being available for shifting and in the highest LCT uptake scenario. This indicates that it seems uneconomic for suppliers to collectively incentivise demand shifting at a rate such as 10p/kWh for this high uptake scenario, whereas at 2p/kWh the model predicts that DSR provides a financially more attractive option.

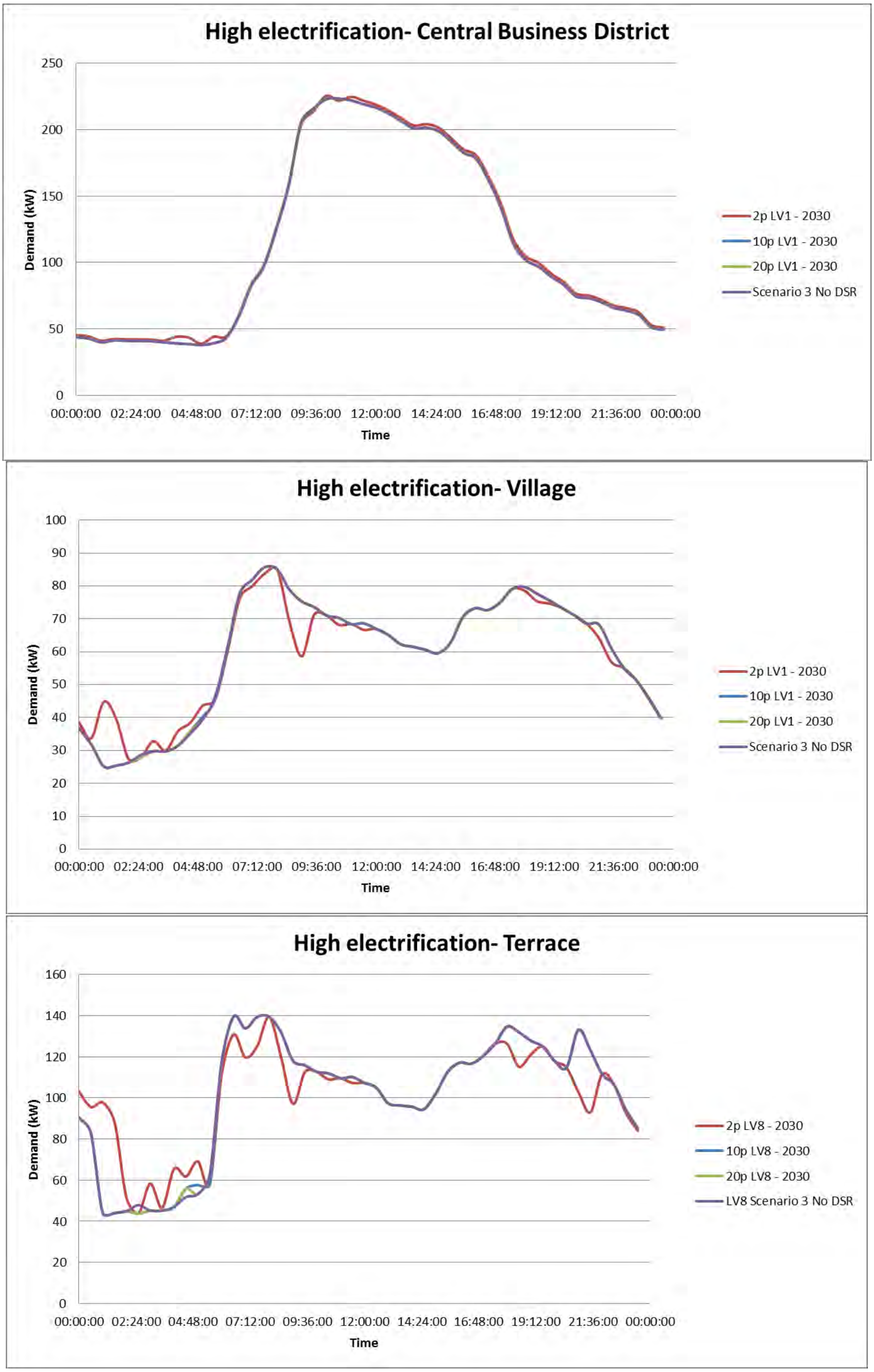


Figure 6 Winter peak daily profiles in 2030 with various levels of DSR incentive applied to three representative LV feeders for high electrification of heat and transport scenario

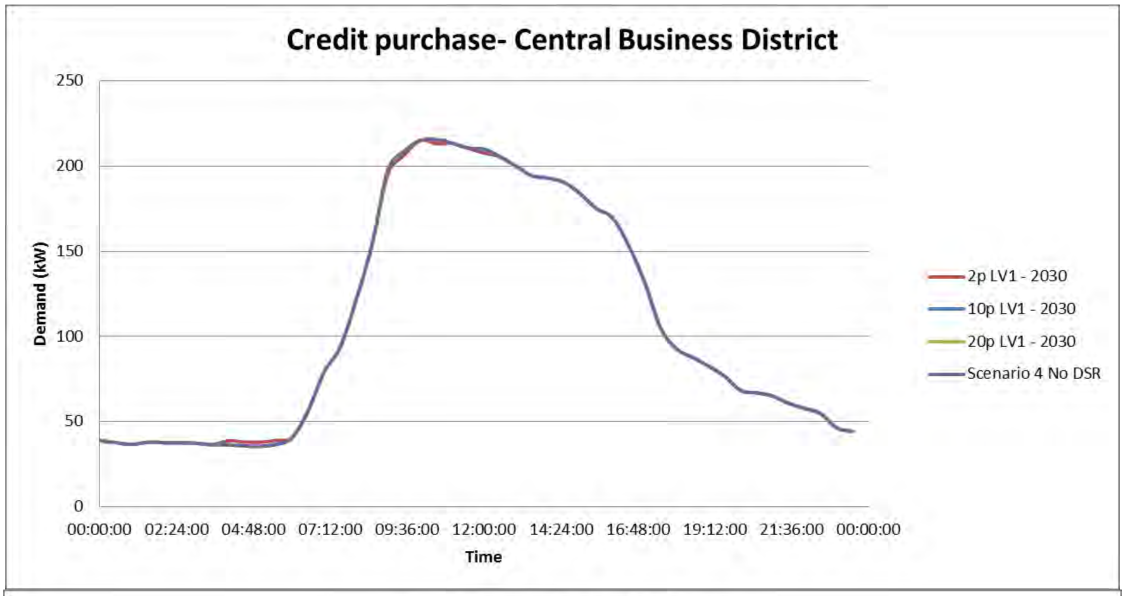
Figure 7 below now considers the same feeders, but under the ‘credit purchase’ scenario, which has the lowest uptake of LCTs.

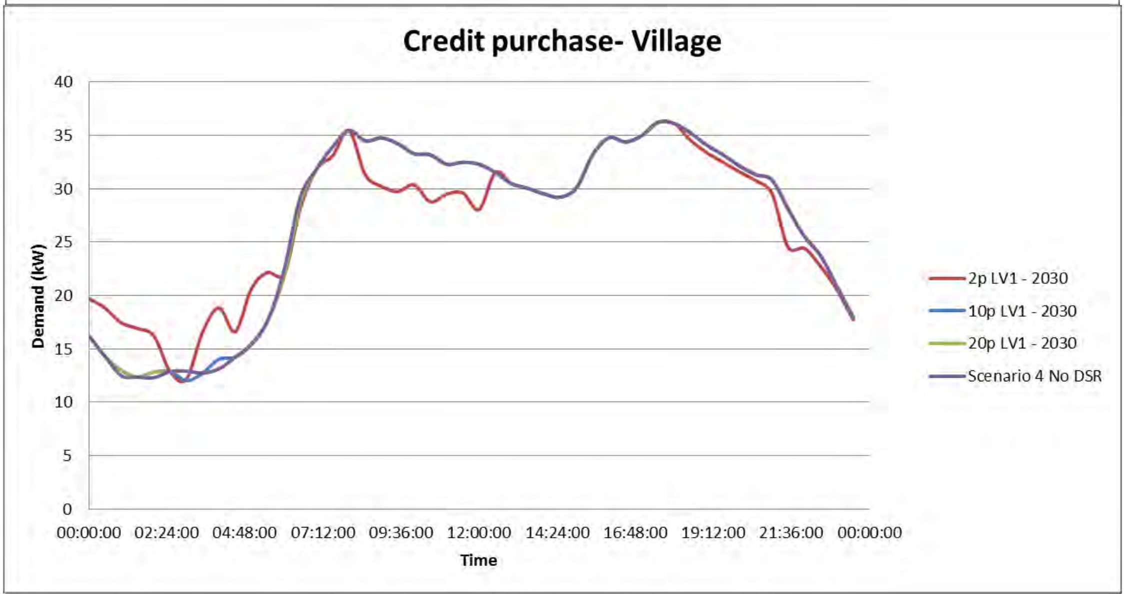
One might expect that the amount of load shifted under this scenario would be less than that described in Figure 6 given that there are fewer LCTs that may be eligible for shifting and it can be seen that in the case of the CBD feeder, very little change is observed.

However, in the case of the village and terraced street feeders, there is actually an increased level of profile re-shaping through DSR compared to that in the high electrification of heat and transport scenario. The reason this occurs is that demand overall is considerably lower. This means that there is essentially more freedom for the supplier to ‘pick and choose’ when it is more beneficial to move demand. In the case of higher demands when, it must be remembered, only a relatively small amount is eligible to be shifted, there is a large amount of demand that must be serviced at particular times, meaning the scope for shifting is actually fairly limited.

When demand levels overall are lower, then the major component of the demand (which is not eligible for shifting) is considerably smaller, meaning that only a small amount of demand must be serviced at a given time. This means that there is more scope to shift the remaining demand with considerably greater freedom. Hence the more significant changes to the demand profiles shown below.

However, it should still be noted that there is still a fairly limited, although greater than previously, amount of demand shifting occurring at the 10p and 20p rates. At the 2p/kWh rate, a considerable amount of shifting is present at various times through the day for both the village, and to a greater extent, the terraced street profile. The amount of demand that is shifted at absolute peak times, however, remains minimal in cases for both rural village and terraced street, again showing that while the shape can be shifted significantly at certain times of day, the peak demand remains fairly constant. It should also be remembered that these load curves are for 2030 where LCTs are more widely proliferated. In the earlier years there would therefore have been less scope for demand shifting.





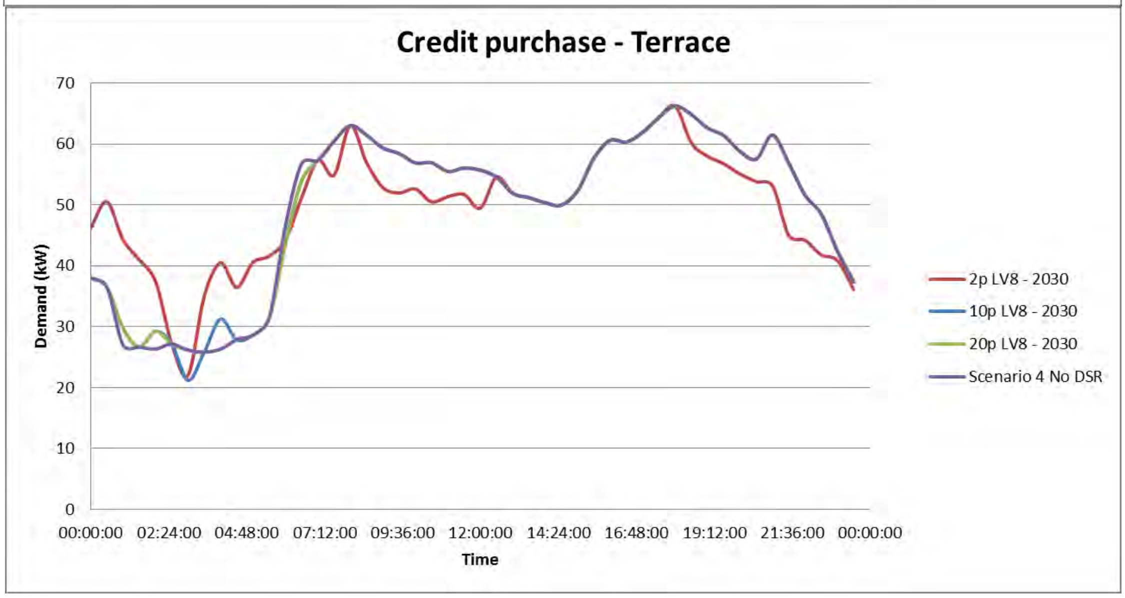


Figure 7 Winter peak daily profiles in 2030 with various levels of DSR incentive applied to three representative LV feeders for credit purchase scenario

4.1.3 Avoided investment attributable to DSR

Having established that certain load profiles do, in fact, alter provided that the cost to suppliers is sufficiently low, it is possible to examine the amount of DNO investment that could be avoided. This effect occurs when the supplier interests coincide with those of the DNO and demand is moved away from peak times, meaning that a reinforcement that would otherwise have been required becomes unnecessary.

This can be calculated by examining the totex investment requirements when no DSR is enacted, and again when supplier-led DSR is present. It is found that in the case to 2030, if the incentive rate is 10p or 20p/kWh, then there is no saving for the DNO. However, if the incentive rate is set at 2p/kWh, as seen earlier, demand profiles could alter significantly. Table 1 captures the extent to which the Transform™ model predicts such effects occur.

Table 1 Amount of totex saved as a result of supplier-led DSR actions assuming incentive rate of 2p/kWh

Scenario	RIIO-ED1		RIIO-ED2	
	Totex savings (£)	Savings as % of totex	Totex savings (£)	Savings as % of totex
High abatement of heat	£17,573,654	3.5%	£235,335,837	6.3%
High abatement of transport	£17,961,041	2.9%	£58,627,083	2.1%
High elect. of heat & transport	£84,948,498	13.9%	£138,268,793	3.7%
Credit purchase	£9,306,176	7.5%	£55,031,688	28.2%

In summary, the available peak reduction from DSR varies over time and with cluster group. Below is shown an example where peak reduction of just over 3% is achieved (for a mid-range cluster group):

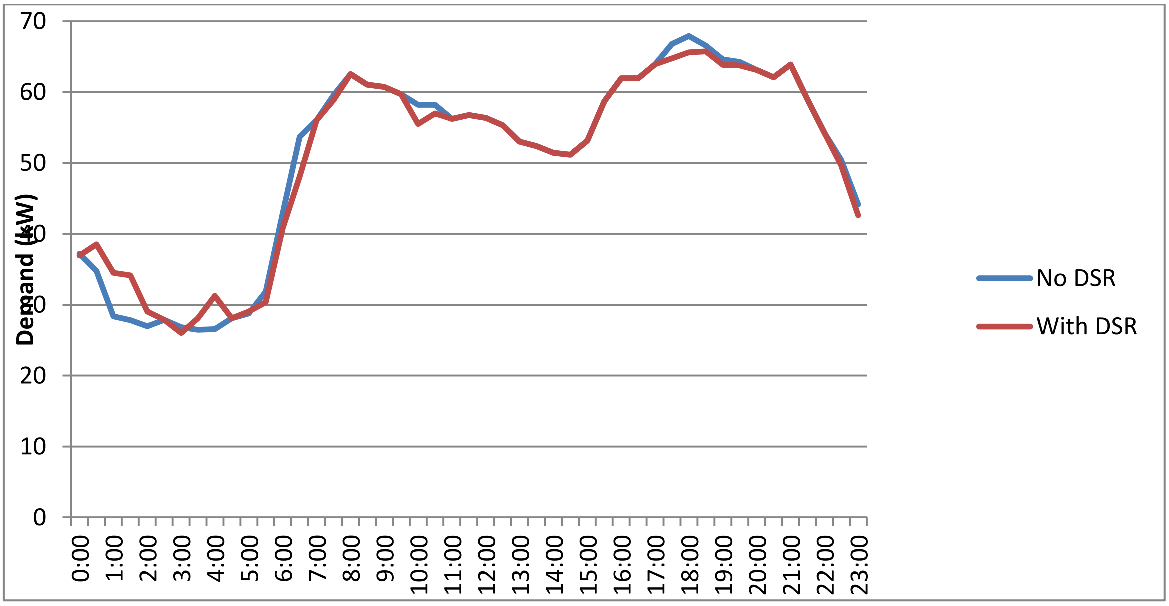


Figure 8 Sample Peak Demand reduction (in this case scenario 3 LV8 cluster group 4 in 2022)

The amount of peak reduction available varies over time and with deployment of LCTs, rising from 0 to around 4% before falling back once LCTs reach higher levels of ownership.

4.2 Load shape modification through direct remote control of demand

Originally the scope also included an assessment of load shape modification through direct control of demand (sending signals to smart appliances, electric vehicle charging points etc) and controlling the demand associated with such loads remotely.

However, following teleconferences with ENA during March/April 2013, it was decided that this was not of interest to this project, given that such a situation would require the ability to send direct control signals to smart meters; something which is not expected to be viable under the current specification.

Therefore, no analysis has been carried out on this subject.

The only cost savings considered through DSR in this report are therefore the impact of price signals sent by energy suppliers to incentivise switching loads due to peaks and troughs in energy prices.

4.3 Impact of following wind generation

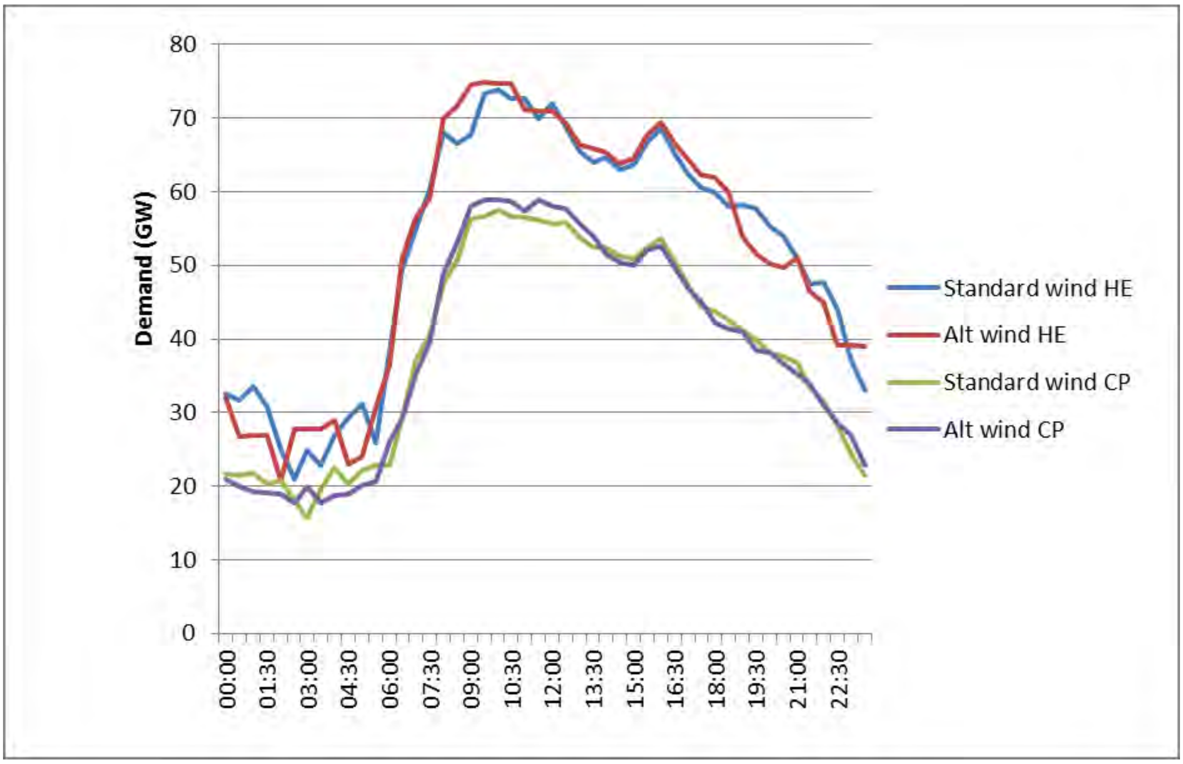
The Transform™ model uses wind profiles to determine how suppliers may wish to shape demand to follow such generation, if the economic conditions are favourable to doing so. This section examines the differences that could be caused by varying from the 'standard' wind profile used to an 'alternative' wind profile.

These profiles (shown in Figure 10, below as 'Standard Wind' and 'Alt Wind 2') were incorporated as part of the work for the Smart Grid Forum in an activity led by Frontier Economics, who have experience in working in this field and sought advice from other industry stakeholders including Elexon.

The two profiles described above are already fairly different in their nature and test the level of response to wind-following under these varied conditions. However, to further explore this, the graph also includes two artificial profiles to test boundary conditions. The first shows high levels of wind consistently throughout the morning, dropping off completely in the afternoon and evening ('Morning Wind'), while the second shows the reverse, with no wind in the morning and a considerable amount consistently in the afternoon and evening ('Afternoon Wind'). It is not envisaged that these two profiles are likely to occur, but, as stated, they are included to demonstrate the extent to which the demand reshaping observed through wind following could theoretically vary.

Figure 9 Four wind profiles showing export on a winter's day in 2030 used for analysis to explore boundary conditions

By looking at these four wind profiles, it is possible to determine the level to which demand may vary if it were to try to follow any one of these. The following graphs (Figure 10) demonstrates the way in which demand varies for a winter's day in 2030 if following one of the above wind profiles, under the 'High electrification of heat and transport' (HE) and 'Credit purchase' (CP) scenarios respectively. It should be noted that the graphs also include the boundary conditions of 'morning' and 'afternoon' wind profiles to demonstrate the extent to which demand could vary, while the 'standard' and 'alt' profiles show a credible amount by which this variation might occur.



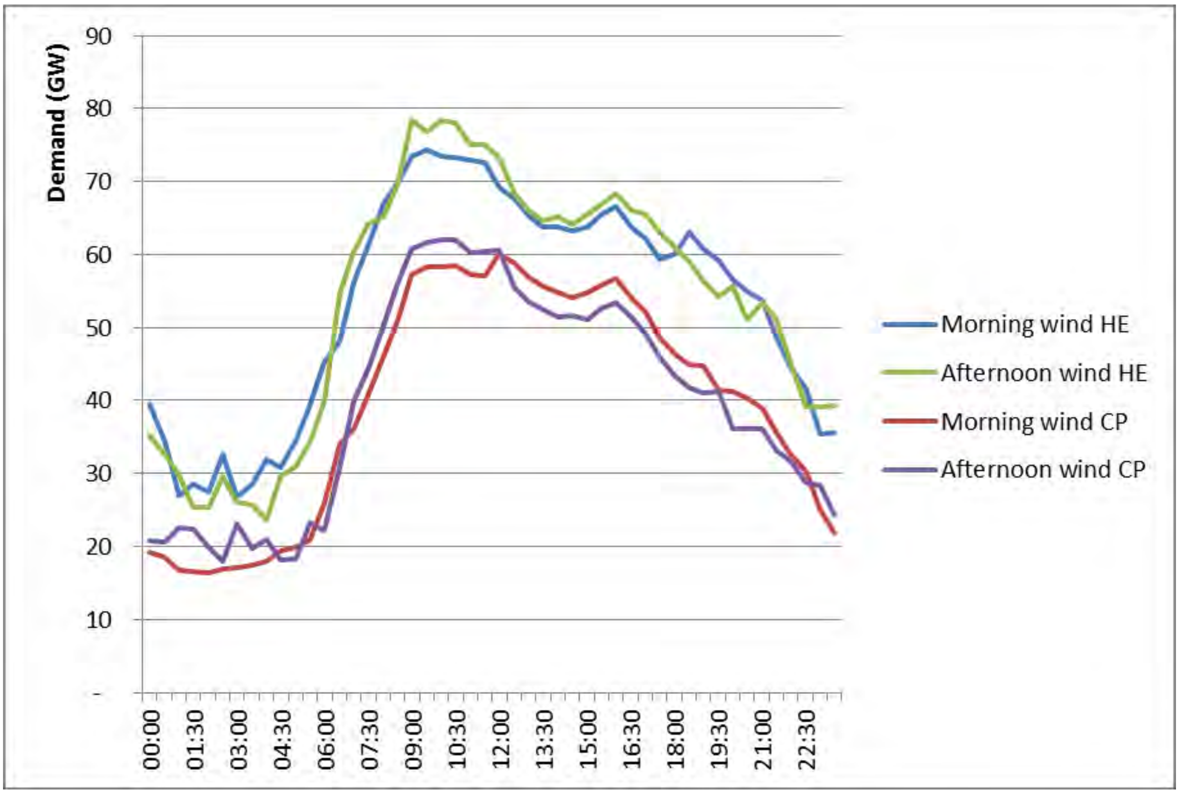


Figure 10 Demand profiles for a winter's day in 2030 showing variation caused by DSR actions of suppliers following wind at a cost of 2p/kWh

The following graphs (Figure 11) indicate the way in which demand can be expected to vary on a terraced street feeder on a winter's day in 2030 under the low uptake of LCT (Credit purchase) scenario, assuming that suppliers attempt to follow wind profiles at a rate of 2p/kWh. It is noticeable that there is significant variation, even in the 'standard' and 'alt' wind profiles with the time of peak shifted by some three hours between them, and also the magnitude of the peak differing by around 10% of demand. The reason that demand may seem to follow wind more readily than following the price signals discussed in previous sections is because the model perceives a greater benefit to doing so. The reason for this is that if wind is plentiful, it becomes a virtually 'free' resource and in the model the cost per kW of generation reduces significantly, meaning that there is significantly more low cost generation available.

The extreme wind profiles used for boundary testing demonstrate that under such conditions, the time of peak may vary significantly (early morning as against evening) but the magnitude of the peak in this case remains fairly constant.

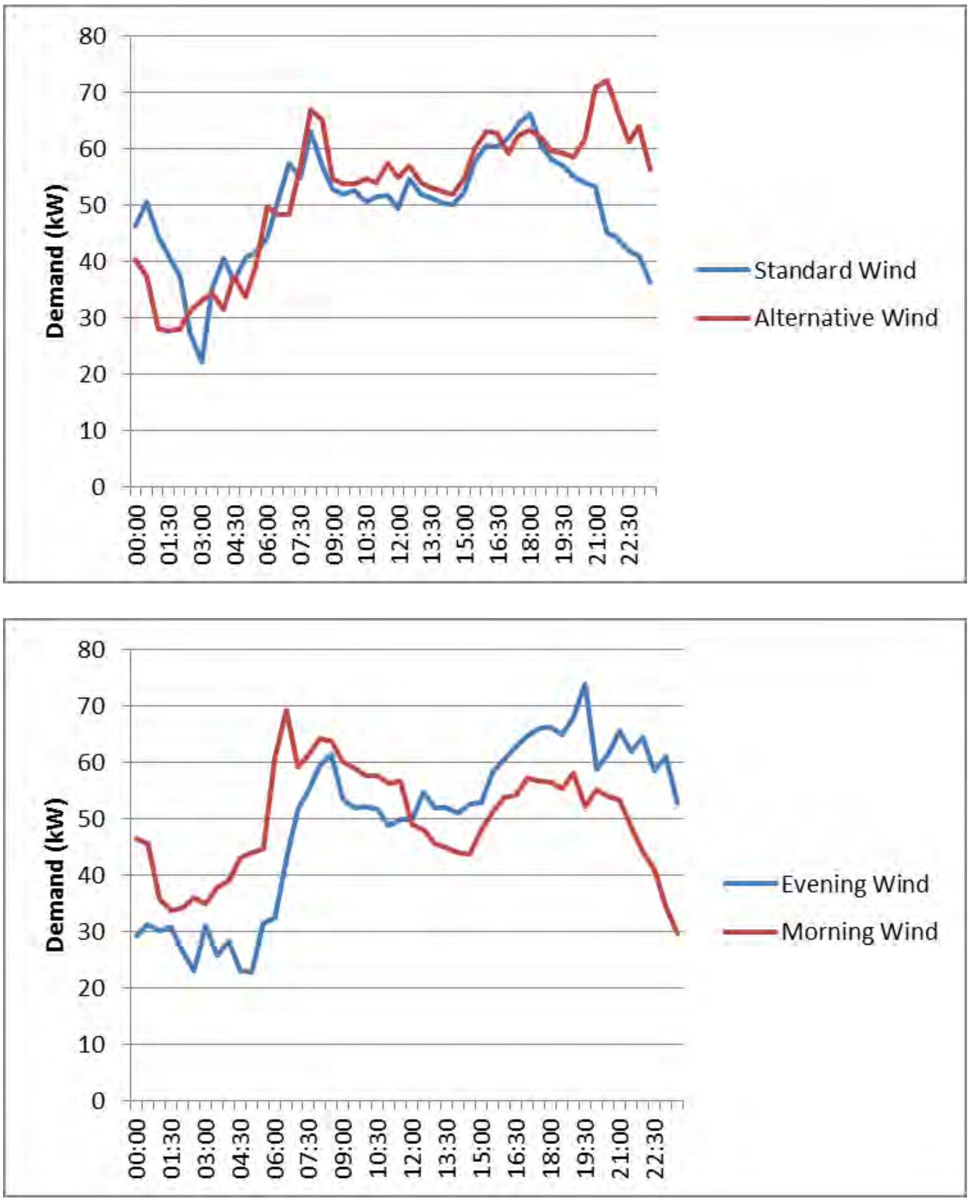
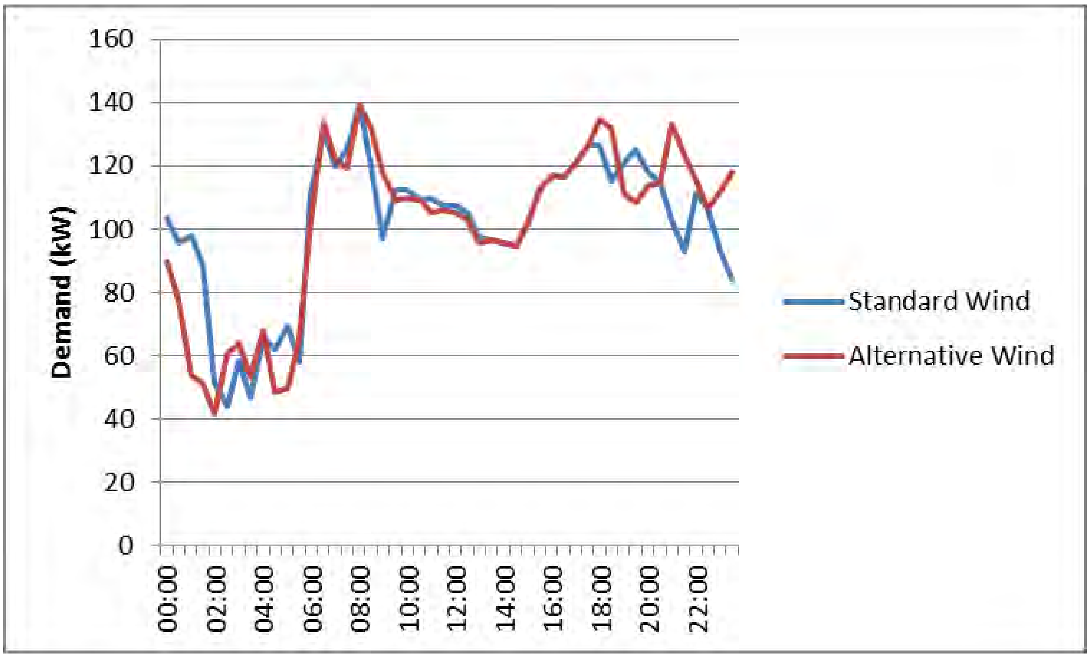


Figure 11 Demand profiles for terraced street LV feeder for a winter's day in 2030 under the 'Credit purchase' scenario with suppliers following various wind profiles

For completeness, the effects on the terraced street feeder of demand following these wind profiles can also be observed in the high uptake scenario (High electrification of heat and transport). These graphs are shown in Figure 12.

It can be seen that in this case, there is very little variation between the 'standard' and 'alternative' profiles in terms of the time or magnitude of peak demand. There is much more variety when considering the extreme 'morning' and 'afternoon' wind profiles, as would be expected. However, even in these cases, the difference in absolute peak demand level is less than 10%, but the load shapes are very different. It is therefore possible that suppliers could in fact increase maximum demand on the network by encouraging consumers to consume when peak demand occurs together with peak wind. Further work will be needed here to ensure this is managed correctly in the future.



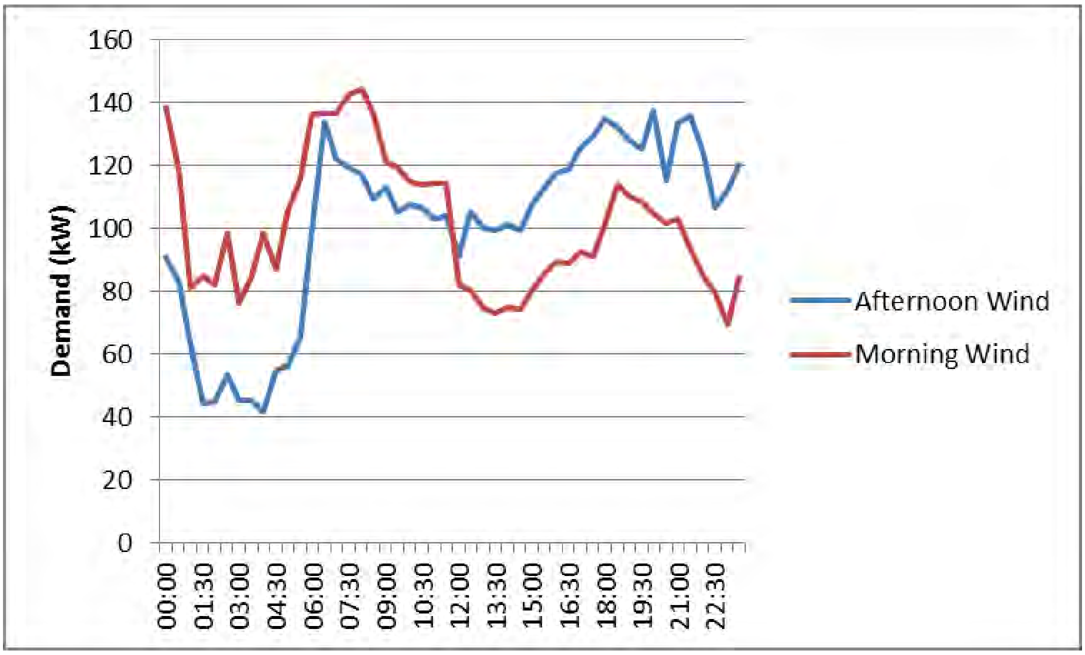


Figure 12 Demand profiles for terraced street LV feeder for a winter's day in 2030 under the 'High elect of heat and transport' scenario with suppliers following various wind profiles

In order to draw out the level of difference in peak demand that arises in any given year, the following graph (Figure 13) shows how the peak demand observed on the same terraced street feeder would vary over the years to 2030 assuming that suppliers attempted to follow these wind profiles at an incentive rate of 2p/kWh. It can be seen that there is considerable consistency between the graphs, although the peak demand increases more quickly in the boundary condition of 'Afternoon Wind', before then realigning with the other profiles by the end of RIIO-ED2.

This result demonstrates that although the demand shape can alter considerably, the actual peak demand level is unlikely to be significantly affected, although as noted earlier there is the possibility that maximum demand could be impacted if peak wind occurs and is incentivised at times of maximum demand.

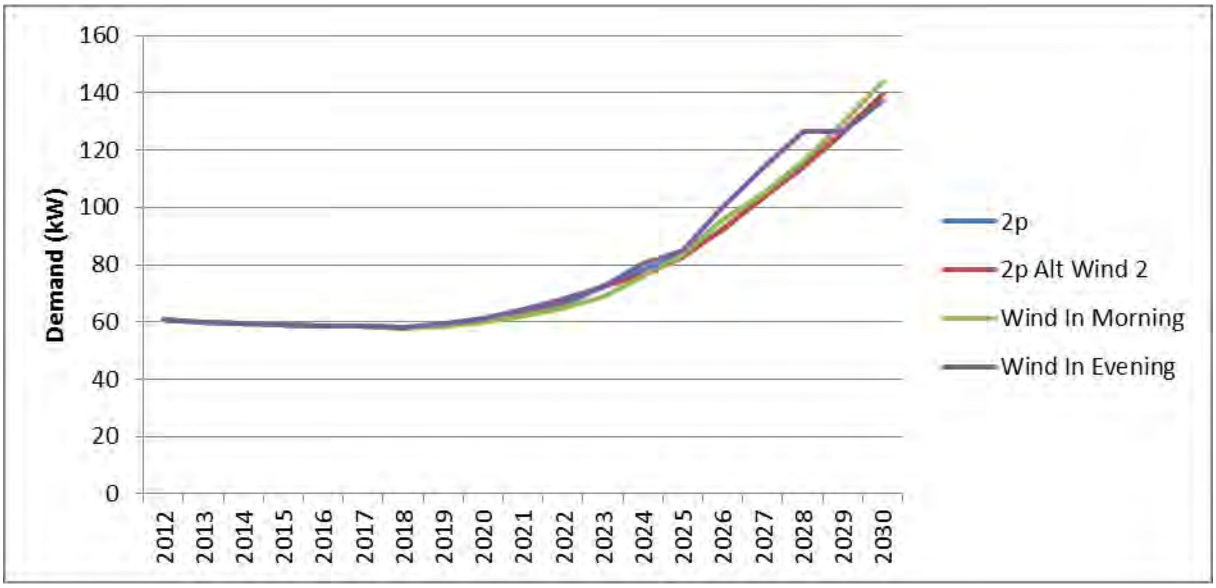


Figure 13 Peak demand by year for LV Terraced Street feeder under the 'Credit purchase' scenario depending on the wind profile selected

4.4 Impact of load shaping on losses

4.4.1 Nationwide losses

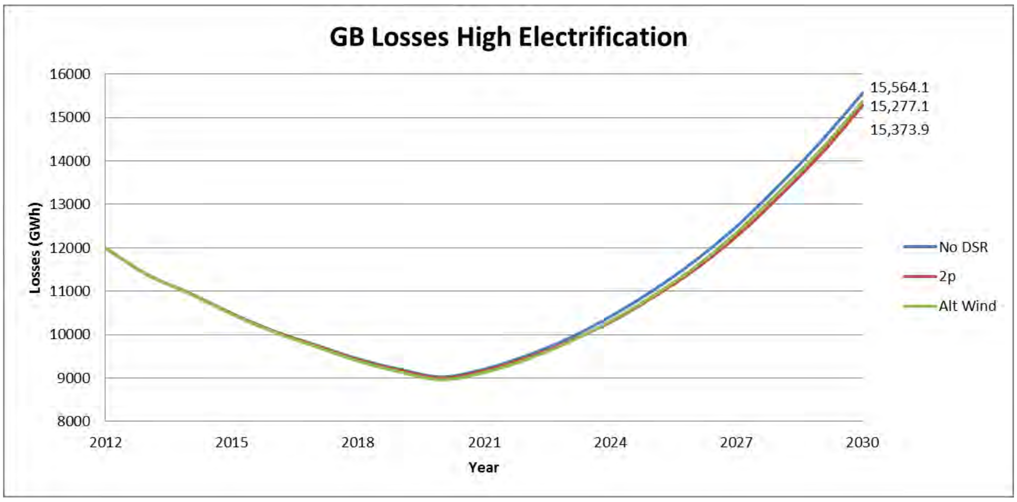
As demand increases, caused in part by low carbon technologies, the associated losses can also be expected to increase. This is because variable losses square with the current being supplied through the network. Hence it can be observed that if a peak demand is increased, the losses are exacerbated. If demand were to be reshaped to reduce these peaks, the overall losses could be reduced, compared to the high peak demand case.

The following graphs (Figure 14) illustrate the expected changes in total losses across Great Britain over the period to the end of 2030, and furthermore show how such losses might be mitigated through the use of DSR measures. In each of the graphs (representing the two scenarios with the highest and lowest growth in low carbon technologies), the blue curve shows the likely changes to losses profile while the red and green curves show how this could be mitigated through the use of two wind profiles (as considered in 4.3).

In each case, the starting profile of variable losses has been assumed to align with previous ENA work in this area, and hence has been taken to be 12.25TWh. This appears to fit with data obtained from Ofgem[2] which lists all DNO losses (fixed, variable and commercial) to be approximately 18.8TWh.

In order to determine the change to variable losses (I^2R losses), the sample daily profiles within Transform were used (summer average representing 6 months of the year, winter average representing ~5.5 months of the year, and winter peak representing two weeks of the year). The I^2 terms for each half hour of each of these three representative days in the base year were calculated and then summed (with appropriate weightings given to each day depending on the portion of the year it represents: 50%, 45% and 5% respectively). This was then indexed such that the starting losses position (12.25TWh) became 100%. For each of the following years, the I^2 terms were then summed again and compared with the base year to give a percentage increase in losses. By simply multiplying this percentage by the starting losses figure (12.25TWh), the losses in any year to 2030 could be calculated.

The total losses in GWh in 2030 are displayed to the right of each curve for clarity.



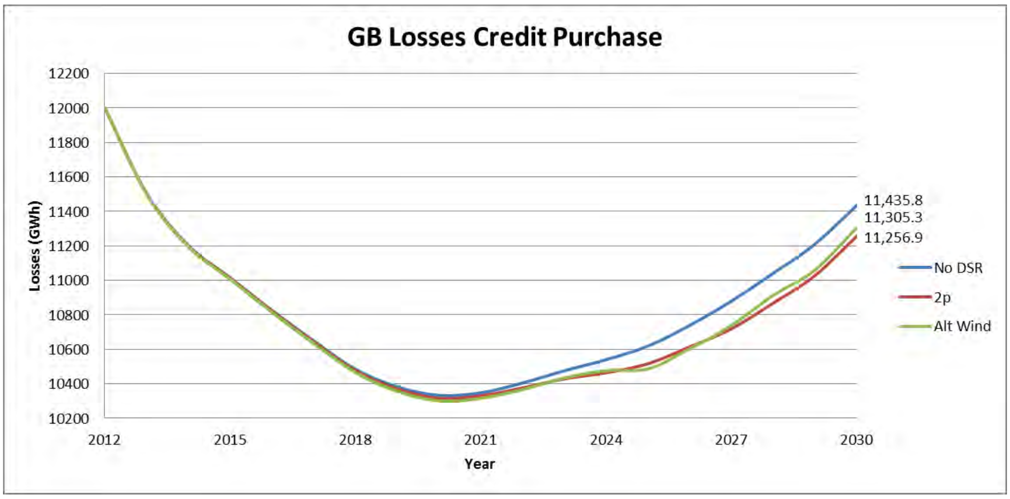


Figure 14 Losses across Great Britain for situations where there is no DSR, and two cases of DSR following different wind profiles at 2p/kWh

2 http://www.ofgem.gov.uk/Networks/ElecDist/Documents1/Distribution%20Units%20and%20Loss%20Percentages%20Summary.pdf

In each of the scenarios there is a noticeable reduction in losses initially, while increased energy efficiency measures and overall demand reduction across the country outweigh any uptake of low carbon technologies. Then, as demand is forecast to grow once prevailing economic conditions become more favourable, and as the uptake of LCTs increases, the load, and hence the losses, increase dramatically from 2020 onwards.

In the case of the credit purchase scenario, the model forecasts that by 2030, losses will have almost returned to the level they are currently at today, whereas in a high electrification of heat and transport scenario, they will far outstrip present levels, increasing from some 12,000GWh to some 15,500GWh.

The effect of DSR, driven by the two wind profiles is still fairly limited. In the case of the high electrification scenario, the greatest benefit realised is some 287GWh, amounting to 1.85%, while in the case of the credit purchase scenario, a saving of 179GWh, or 1.6% is obtained. This represents the best-case scenario of the two wind profiles examined, but these are thought to be representative and while it would be possible to construct artificial profiles that could show a more significant benefit, these are unlikely to materialise in practice.

Furthermore, analysis has been undertaken to establish what the overall benefit of losses reduction is to a network operator. Table 2 below shows what the NPV level of savings would be where the losses have been calculated for each year, and converted to a financial figure using a value of £60/MWh and discounting annually by 3.5% in line with assumptions taken elsewhere in this report.

Table 2 Savings in losses through DSR actions initiated by suppliers to follow wind profiles

	Losses savings using standard wind profile (£m)	Losses savings using alternative wind profile (£m)	Average losses savings (£m)
High electrification of heat and transport	63.678	24.876	44.277
Credit purchase	40.269	31.212	35.740

As previously stated, there are some concerns regarding the overall load profile used. Hence further analysis was also undertaken to examine the effect of using a different demand profile. A demand profile was constructed that accurately reflects the demand seen today and this profile was used for a repeat of the analysis. It was found that the amount of losses saved remained of the order of 1.5 – 2%, largely because although there is a pronounced evening peak, the difference between the peak demand and the minimum overnight demand is smaller than in the original modelled profile, making some DSR less attractive.

4.4.2 Losses on individual feeders

In order to establish the way in which losses might vary on individual feeders, the same three representative networks as previously have been considered: CBD (LV1), terraced street (LV8) and rural village (LV9).

For this analysis, cluster group 4 was again examined so as to represent a reasonable level of clustering, and for consistency with other analysis within this report. The characteristics of these feeders is known (in terms of length, conductor size etc). The load was assumed to be connected in ten equal amounts along the feeder, thus breaking the circuit into ten sections, each with its own impedance. The amount of current travelling through each section could then be analysed, to determine the initial losses position. By observing how the load (and hence current) changes over time and taking the change in the square of the current (assuming constant impedance) the change in variable losses has been calculated.

This is shown in the below graphs (Figure 15 and Figure 16) as the blue curve, with two additional curves also drawn. These show how the losses would differ under two wind profiles (discussed in 4.3 above) when a payment of 2p/kWh is assumed. In this way, the change in losses position at 2030 can be calculated and is shown to the right of each of the graphs for clarity in kWh terms.

The graphs below (Figure 15) indicate that under the high electrification of heat and transport scenario, losses are likely to remain fairly constant until 2021 and then increase sharply as demand increases.

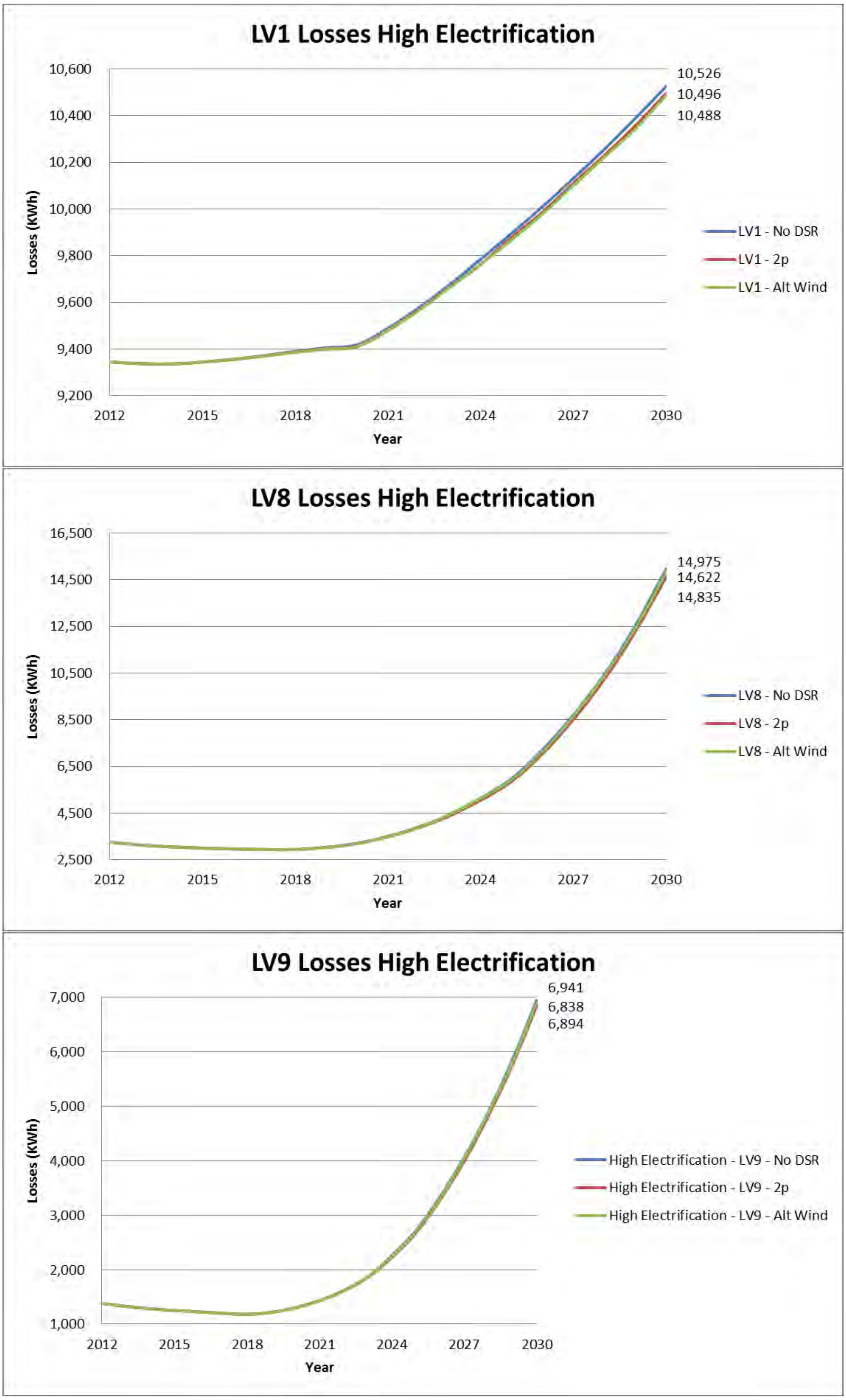


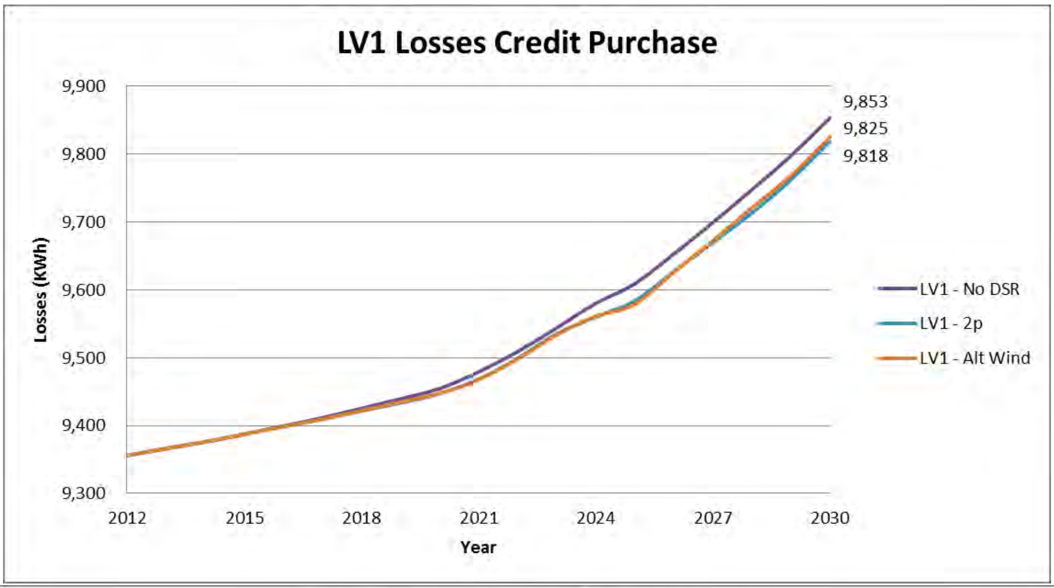
Figure 15 Losses on representative feeders under high electrification of heat and transport scenario under no DSR, and DSR available at 2p/kWh for two wind profiles

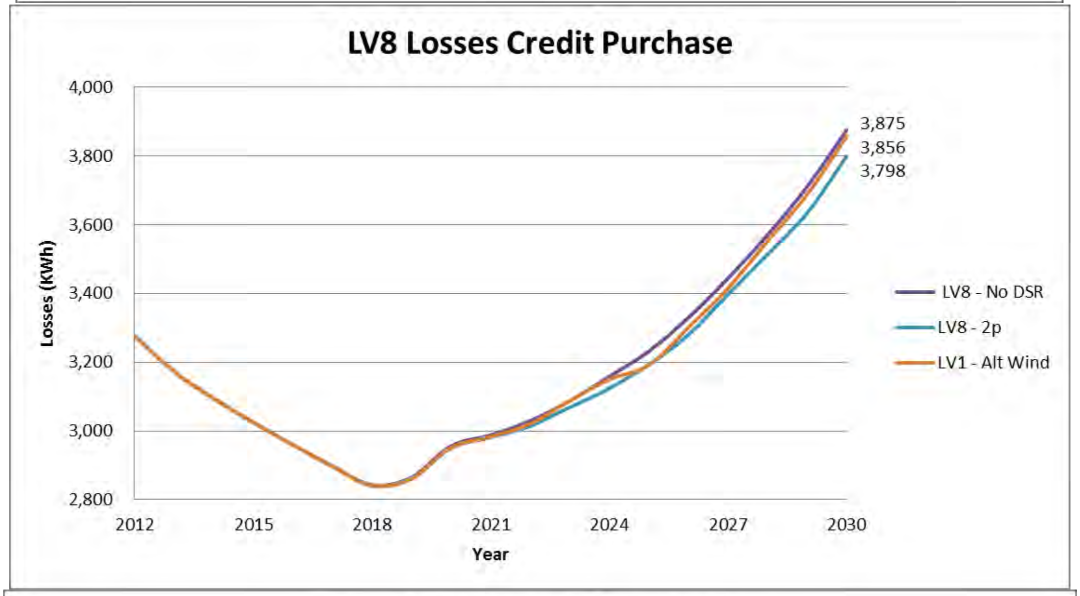
Hence it can be observed that on these individual feeders there is a reduction in the increased losses projected at 2030 of up to 353kWh or 2.35% in the case of the terraced street feeder. The reductions are smaller for CBD (LV1) and rural village (LV9).

The analysis has then been repeated for the credit purchase scenario; the results of which are shown in Figure 16 below. In these graphs, when considering the domestic feeders (LV8 and LV9) it can be seen that there is initially a significant reduction in losses arising from the fact that demand reduces through energy efficiency (and hence there is an associated squaring effect of this when considering the losses) without there being the same level of uptake of low carbon technologies to increase demand that was seen in Figure 15. Losses again begin to increase around 2019 and continue to do so steadily throughout ED2.

In the case of the CBD feeder, the reduction until 2019 is not observed; instead a steady increase is seen, not dissimilar to that observed under the high electrification of heat and transport scenario previously. This can be attributed to the fact that there are fewer, larger buildings connected to these feeders that do not benefit as much from increased energy efficiency as a larger number of smaller buildings on other feeders do.

From the graphs below it can be seen that the level of losses that are offset by DSR is lower than that in the high electrification of heat and transport scenario, being up to 77kWh or just under 2%.





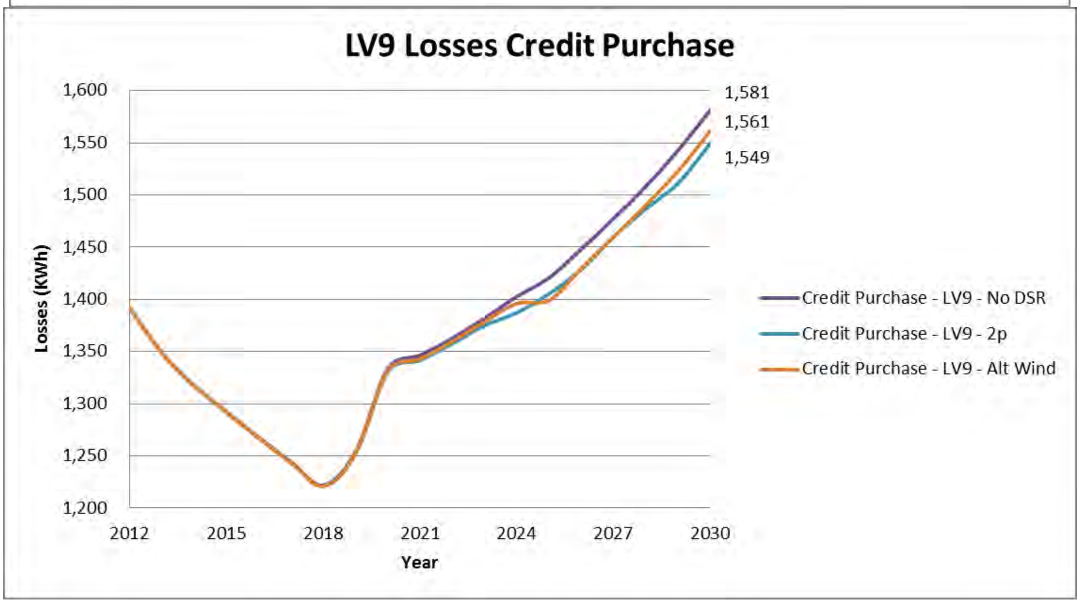


Figure 16 Losses on representative feeders under credit purchase scenario under no DSR, and DSR available at 2p/kWh for two wind profiles

4.5 Impact of potential peak demand reduction

As a final piece of analysis, investigations have also been carried out to determine what the potential impact on network investment and losses would be if DSR actions were to bring about a reduction in peak demand.

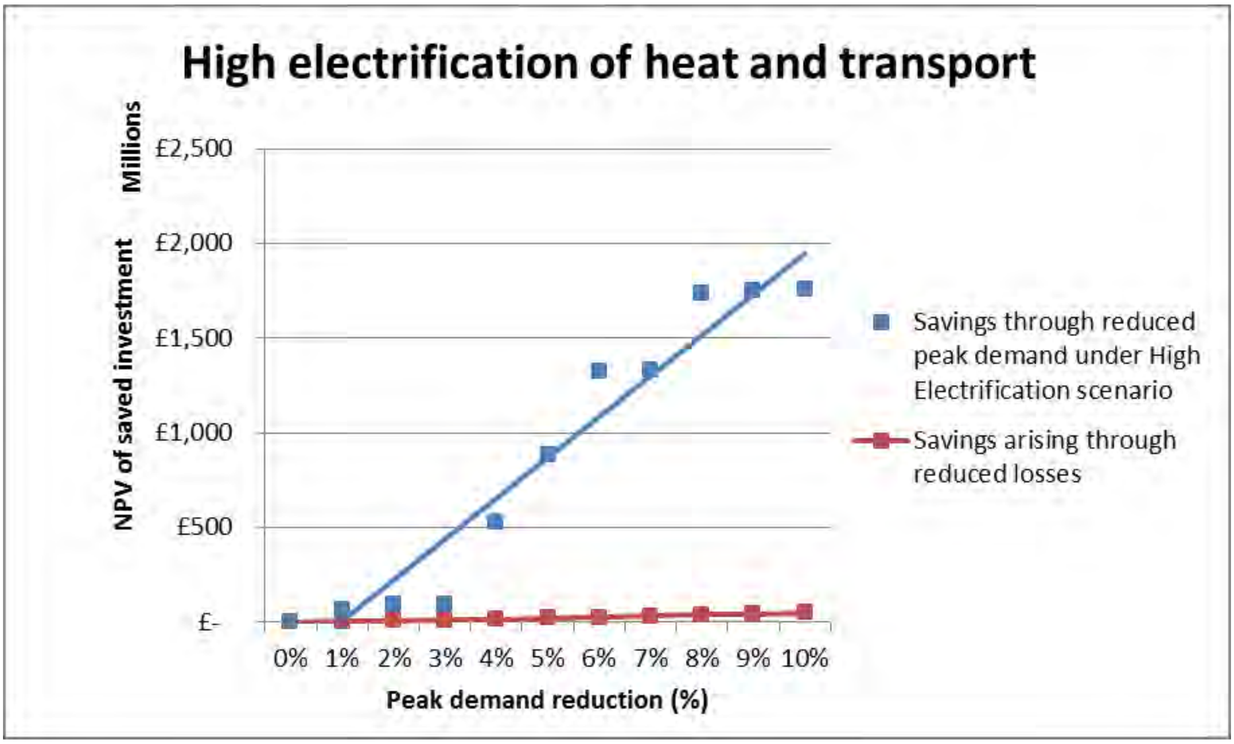
To this end, studies have been carried out on a GB basis, examining a reduction of up to 10% in peak, with the total energy saved at this peak time shared across the rest of the day. In order to ensure that this does not merely create another peak in the next half-hour, the approach taken was to limit the time of day when demand could be shifted to being a minimum of one hour either side of the time when the peak demand was being reduced. In other words, if the peak demand occurred at 6pm and a reduction of 5% in that demand meant that the peak was essentially flattened between 5.30 and 6.30, then demand would be shifted such that the demand could not increase between 4.30 and 7.30pm. In order to allow the analysis to proceed, the assumption was then taken that the demand that is moved from the peak time is evenly shared across the remaining portion of the day (midnight to 4.30pm and 7.30pm to 11.30pm in the above example). While this will not necessarily be true, it is not considered that this assumption will have a significant impact on the results.

The following graphs (Figure 17) demonstrates the level of saving in investment that can be made through a reduction in peak demand. The case considered is the saving to 2030 where DSR acts every year to reduced peak demand by a given percentage (between 0% and 10%). This may slightly overstate the benefit in early years.

It can be seen that over the period, for the high electrification scenario the NPV of saved investment accruing through this reduced peak is £1.75bn while the NPV of saved costs through reduction in losses is approximately £50m. The losses benefit increases fairly linearly over the period with between £3m - £7m for each percentage reduction in demand (averaging at £5m per % demand reduction).

For the credit purchase scenario, the level of saved investment is much more modest, being up to £35m for a 10% reduction in peak demand and an associated saving of up to £45m for losses with this peak demand reduction.

It may appear that the level of losses saved through DSR is somewhat disproportionate to the amount of investment that can be saved as a result of networks no longer requiring reinforcement. The reason for this is that there is a defined trigger threshold for when networks require investment. If the demand is slightly above this threshold, then reinforcement is necessary, but if it sits even slightly below, then no reinforcement is required (and hence investment is deferred). Hence by saving a comparatively small amount of losses, it is possible to reduce demand below this threshold, meaning that although the losses saving value is small, the amount of deferred investment can be significant.



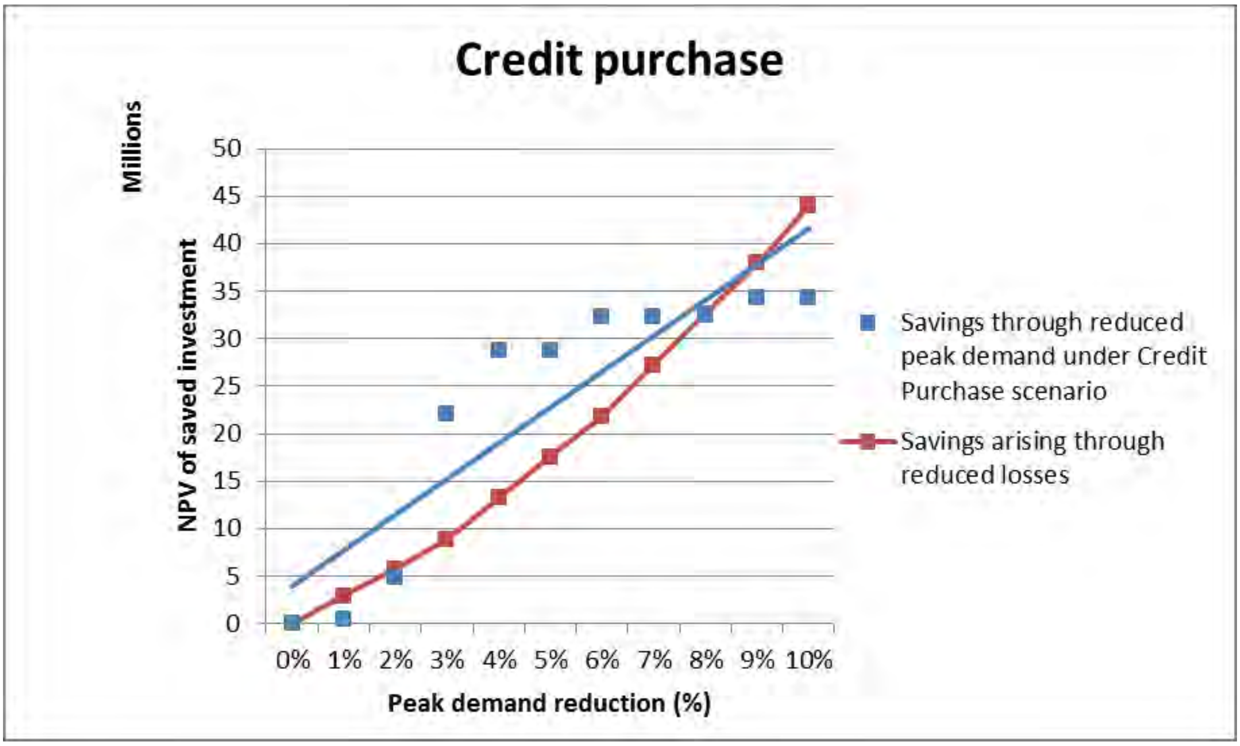


Figure 17 NPV of saved investment to 2030 as a result of peak demand reduction through DSR and associated reduction in losses

5 Literature review of DSR and ToU experience

5.1 DSR in the Global Context

A reasonably large number of studies have been conducted looking at consumer attitudes and actions to Demand Side Response. DECC published "Demand Side Response in the domestic sector- a literature review of major trials" in August 2012. This major review, conducted by Frontier Economics considered the global evidence for the success of DSR in the domestic sector and identified 30 significant trials including 15 which used "Time of Use Tariffs" to incentivise demand shifting/reduction.

The table below is adapted from the report and shows the results achieved in reducing peak demand for various tariffs in nine international trials.

Table 3 Summary of DSR trials conducted globally

Trial	Country	Number of participants	Average reduction in peak demand	Peak to off-peak price differential
Ontario Smart Price Pilot (2006-2007)	Canada	124	0%	140%
Idaho DSR trial (2005-2006)	USA	85	0%	184%
Missouri CPP trial (2004-2005)	USA	91	0%	349%
CL&P Pilot (2009)	USA	188	2.50%	208-408%
California State-wide Pricing Pilot (2003-2004)	USA	226	3.50%	200%
myPower Trial (2006-2007)	USA	379	4.50%	187%
PSE's ToU trial (2001-2002)	USA	300000	5%	unknown
Ireland Electricity Smart Metering Behaviour Trials (2009-2010)	Ireland	2,920	9.50%	143-271%
PG&E's Trial (2008-2010)	USA	86,222	11%	varied

We can see that there is an enormous variation in the shift achievable. The central case appears to suggest a reduction of around 5% may be achievable. It is noticeable in the trials that involve air conditioning systems that the peak shift achievable is generally much higher.

For instance, the largest reductions were found for consumers with central air conditioning in the Xcel *Energy Trial*[3] where the average critical peak demand reduction was 38%, and the *Integral Energy*[4] *Trial* in Australia, where the average critical peak demand reduction was 37%. Since there are great similarities between heap pumps and air conditioners, this suggests that peak shifting for domestic heat pumps may be substantial.

A major survey in 2008[5] looked at the acceptance of load shifting in different domestic appliances, this found:

- 77% of consumers would accept a shift of three hours for washing machines and tumble dryers, but they were concerned about leaving laundry for a longer time as it might go mouldy or become creased.
- For dishwashers, 77% would accept a shift of at least three hours, and the main concern about smart operation was noise during the night.
- There were some objections to smart operation of fridges and freezers due to concerns about safety and the potential for a reduction in food quality
- Reported willingness to accept automation was highest for interventions affecting fridges and freezers and lowest for those affecting cookers.

5.2 UK Attitudes to DSR

In a recent UK study, Consumer Focus engaged Ipsos Mori in 2012 to conduct a major study into "Consumer Experiences Of Time of Use Tariffs". In this study Mori interviewed almost 6,000 UK electricity consumers about their experience of using time of use tariffs (mostly economy 7 or Economy 10). This study found that:

- 50% of ToU tariff users deliberately run appliances, other than water and space heating systems, at off peak periods to save money.
- 38% have no storage heating and do not use any appliances at off peak rates
- 12% of ToU tariff users have been caused considerable upset or discomfort, ill health or financial problems attributed to their tariff or heating system. This rises to 15% among those with storage heating.
- There are TOU Tariff "evangelists", these are generally retired people and home workers, both of whom may spend a lot of time in the home and give much attention to optimising their power usage.
- Some of their lifestyle adaptations may seem extreme to observers, for example ironing at night, or cooking a meal in the small hours of the morning.

Overall, the evidence suggests that the introduction of DSR with some form of economic incentive in the UK would:

- Be welcomed by some portions of the population
- Result in actions being taken by some consumers to reduce demand at peak times
- Be more effective if coupled with automation of devices
- Overall result in a demand shift of up to 5%, or possibly more if the home has a heat pump or air conditioning unit.

[3] Faruqui and Sergici, 2009, Household Response to Dynamic Pricing of Electricity- A Survey of the Experimental Evidence
[4] Energy Market Consulting Associates, 2009, Smart Meter Consumer Impact: Initial Analysis
[5] Mert et al, 2008, Consumer acceptance of smart appliances.

6 Conclusions

The main conclusions that can be drawn from the analysis contained in this report are as follows:

- Based on data from National Grid, demand levels are expected to reduce steadily initially (until around 2019) given the increases in energy efficiency and low initial movement towards electrification of heat and transport.
- The network reinforcement costs associated with meeting the demands placed on the network by LCTs are low in RIIO-ED1 but increase rapidly and significantly in ED2.
- The costs associated with meeting these demands are very similar for three of the DECC scenarios, with the 'Credit purchase' scenario representing an outlying position.
- Demand is likely to be reshaped if a supplier only needs to pay a customer 2p/kWh of demand moved. If the required rate to be paid is nearer to 10p/kWh, the results from the model based on marginal cost of generation show that this becomes uneconomic from a supplier perspective.
- Demand reshaping is more prevalent for feeders supplying largely domestic load, rather than those focused on commercial load.
- Although demand is reshaped significantly at 2p/kWh, the change to peak demand is still fairly minimal (normally less than 10% and in some cases, negligible).
- Assuming DSR can take place at a cost of 2p/kWh for a supplier, the amount of network reinforcement that is avoided varies from £9m - £85m in ED1 and from £55m - £235m in ED2 for the various scenarios. All figures given in discounted totex terms.
- It has been shown that demand profiles could vary with different wind profiles, with peak demands moving by up to three hours and varying by up to 10%.
- If DSR incentivises demand reduction at peak times by up to 10%, it has been shown that a saving of up to £1.75bn in discounted totex over the period to 2030 could be made
- Losses will be reduced through DSR actions and have been shown to save between £35m and £45m on average (on an NPV basis in the period to 2030) depending on the scenario considered.
- Losses have been considered on individual feeders and have been shown to reduce by approximately 2% for supplier initiated DSR as against the predicted amount of losses with no DSR actions in place.
- A review of DSR trials and customer attitudes has shown that overall customers are receptive to DSR measures, but that the level of incentive must be sufficiently high to encourage behaviour. This level is considerably higher than the 2p/kWh which is indicated by the analysis in this report to be economic for suppliers to achieve reshaping through DSR. This raises the risk that UK consumers may be less responsive to DSR.
- An average demand reduction of 5% seems feasible, provided that the incentive rate is appropriately set.
- The earlier analysis showed that if a 5% reduction in peak demand could be achieved, then a saving of between £29m and £885m is possible over the period to 2030 depending on the DECC scenario considered
- Response to DSR trials has shown that the most effective results are obtained in areas where some heating or cooling load (such as air conditioning) can be shifted.

The following table (Table 4) is reproduced from the ENA report 'Analysis of Network Benefits from Smart Meter Message Flows (Interim Review) and has been updated with the figures previously given in this report. All figures are in NPV format, using a 3.5% discount factor, consistent with other analysis in this report.

Again, it must be stressed that all figures in this table are benefits realised via supplier-led DSR through time of use tariffs. Additional benefits may accrue through any network operator-led DSR, or through the use of aggregators or individual contracts with specific industrial and commercial customers for demand management, but they are not captured in this report.

Table 4 Summary of savings accruing to a DNO through the use of supplier led DSR measures

Category	Nature of Benefit	Basis of Derivation	ED1 Period Benefit (£m)	ED2 Period Benefit (£m)	Notes
Responsive Demand - TOU tariffs	Reduced need for network capacity to meet peak demand	Avoided cost of reinforcement due to improved load factor releasing capacity headroom	9.3 – 84.9	55.0 – 235.3	Based on LCT growth in the various 4th carbon budget scenarios and taking outputs from Transform for the two scenarios giving the extreme figures. For this analysis, no distinction has been drawn between response to ToU incentives and use of smart appliances, as discussed in the report
Responsive Demand - Load Control	Remote control or smart appliance managed responsive demand				
Management of Network Losses	Mitigated increase in variable I^2R network losses due to improved load factor	Current level of variable technical losses assumed to be 12.25TWh and predicted to increase in line with demand to 2030 following profiles in Transform derived from National Grid and DECC data	3.7 – 5.7	32.1 – 38.6	Based on DECC 4th carbon budget scenarios 3 and 4 assuming losses valued at £60 per MWh (DR5)

ANNEX 29: FIXED COSTS OF SINGLE LICENSEE STATUS

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Contents

1. Executive Summary

Electricity North West is the only Distribution Network Operator (DNO) that is in an ownership structure that does not contain another DNO. As a consequence of this, we incur a level of fixed costs that is higher than other DNOs (because the other DNOs can share costs with companies in the same group).

We asked KPMG to analyse the level of fixed costs that a single licensee would incur above the level that would be expected of DNOs in an ownership group that included two DNOs. KPMG's report estimated that the fixed cost uplift which Electricity North West should be afforded relative to other DNOs as a result of its single licence status is £10.5m per year (2011-12 prices). We included this report in our July 2013 plan and are pleased that Ofgem recognised this as a "*well presented report*".

We used the results of KPMG's analysis in testing that our forecast costs represent an efficient level of costs for a single licensee group.

Ofgem's cost assessment analysis undertaken as part of its Fast Track decision did not take account of the fixed costs of being a single licensee. This resulted in the level of business support costs included in our July 2013 plan being assessed as being inefficient. Oxera has undertaken analysis for us that considers alternative assumptions within Ofgem's business support models. Oxera has also considered alternative modelling approaches such as regression analysis. This analysis demonstrates that Ofgem's assessment of our business support costs as part of its Fast Track decision was materially distorted by an inappropriate assumption regarding fixed cost normalisation; alternative models suggest materially higher modelled efficient costs for Electricity North West.

We also asked Oxera to assess whether it was possible to calculate the level of fixed costs by ownership group econometrically based on the data provided by DNOs in July 2013. Whilst the results of this analysis are not fully intuitive, possibly due to the small sample size used, they do disprove the hypothesis that fixed costs vary linearly by licensee, demonstrating that smaller companies incur a higher level of fixed costs.

Overall, we are confident that our plan offers excellent value for money for our customers and that the benefits in other parts of our plan outweigh these higher costs. Despite the inclusion of these costs our customers will pay some of the lowest prices for electricity distribution in Great Britain during the RIIO-ED1 period. Last year Ofgem assessed the total costs of each DNO's business plan and its analysis showed that our total costs are amongst the lowest of any DNO. This efficient cost base feeds directly into lower prices for our customers. Our leadership in our industry demonstrates that our customers benefit considerably from being served by Electricity North West. Electricity customers connected to our network receive some of the best quality of supply for some of the lowest costs of anywhere in the country. Their service is provided by an effective business focussed solely on the North West that has a proven track-record in innovation, enabling a rapid and effective response to any new challenge that might arise.

We accept that single licensee status is not an inherent characteristic and that it is possible that during the course of RIIO-ED1 our status could change. If we become part of an ownership structure that includes one or more other DNO licensee (either because our current owner purchases another licensee or because we are sold into a group that already includes a DNO licensee) we agree that an adjustment should be made to our cost baselines for fixed costs to ensure that any fixed cost allowance that we no longer need is returned to customers.

2. Ownership Structure of Licensees in Great Britain

The ownership structure of Distribution Network Operators is set out in the following figure and table:

1. Western Power Distribution: West Midlands (WMID)
2. Western Power Distribution: East Midlands (EMID)
3. Electricity North West Limited (ENWL)
4. Northern Powergrid (Northeast) Ltd (NPgN)
5. Northern Powergrid (Yorkshire) plc (NPgY)
6. Western Power Distribution: South Wales (SWALES)
7. Western Power Distribution: South West (SWEST)
8. UK Power Networks: London Power Networks (LPN)
9. UK Power Networks: South East Power Networks (SPN)
10. UK Power Networks: Eastern Power Networks (EPN)
11. Scottish Power Distribution Ltd (SPD)
12. Scottish Power Manweb plc (SPMW)
13. Scottish & Southern Energy: Scottish Hydro Electric Power Distribution (SHEPD)
14. Scottish & Southern Energy: Southern Electric Power Distribution (SEPD)

<table>
<tr><th>Group</th><th>Operating area</th><th>Licensees in ownership group</th></tr>
<tr><td>Electricity North West</td><td>North West</td><td>1</td></tr>
<tr><td rowspan="2">Northern Power Grid</td><td>North East</td><td rowspan="2">2</td></tr>
<tr><td>Yorkshire</td></tr>
<tr><td rowspan="4">Western Power Distribution</td><td>West Midlands</td><td rowspan="4">4</td></tr>
<tr><td>East Midlands</td></tr>
<tr><td>South Wales</td></tr>
<tr><td>South West</td></tr>
<tr><td rowspan="3">UK Power Networks</td><td>London</td><td rowspan="3">3</td></tr>
<tr><td>South East</td></tr>
<tr><td>East</td></tr>
<tr><td rowspan="2">Scottish Power</td><td>South Scotland</td><td rowspan="2">2</td></tr>
<tr><td>Merseyside & North Wales</td></tr>
<tr><td rowspan="2">Scottish and Southern Energy</td><td>North Scotland</td><td rowspan="2">2</td></tr>
<tr><td>South</td></tr>
</table>

Electricity North West is the only DNO that is in an ownership structure that does not contain another DNO.

3. Quantification of Fixed Costs Incurred by Licensees

3.1 Bottom Up of Level of Fixed Costs - KPMG

Analysis based on 14 licensees will not appropriately calculate the level of fixed costs that would be required for an efficient single licensee (because all other DNOs belong to ownership groups that include multiple DNOs).

We asked KPMG to analyse the level of fixed costs that a single licensee would incur above the level that would be expected of DNOs in an ownership group that included two DNOs. KPMG's report 'Estimating a fixed cost uplift allowance for RIIO-ED1' contains the results of its analysis. KPMG also tested whether any of the fixed costs could be diversified by outsourcing these activities. Its subsequent report 'Outsourcing suitability assessment' contains this analysis. KPMG's two reports can be found as Appendices 1 and 2 to this annex.

We included KPMG's reports in our July 2013 plan and are pleased that Ofgem recognised this work as "*a well presented report*".

In summary, KPMG undertook a bottom up approach to assessing how individual elements of our closely associated indirect and business support cost base would change if we were to double the size of our network. Its report identified fixed costs and semi variable costs (costs which are not fixed but would not change proportionately with the size of the network, equivalent to Ofgem's group-variable costs definition). It did not seek to identify the cost drivers associated with semi-variable costs. Where possible it cross referenced its analysis to academic research and management literature for evidence in relation to economies of scale that have been achieved. The following table summarises the results of KPMG's analysis.

2011-12 prices Net distribution		Single licensee group			2 licensee group		
		Fixed costs	Semi variable costs	Total fixed plus semi variable	Fixed costs	Semi variable costs	Total fixed plus semi variable
Closely Associated Indirects	Network design & engineering	0.8	1.1	1.9	0.8	1.2	2.0
	Engineering management and clerical support & Project management	0.5	0.6	1.1	0.5	0.8	1.3
	System Mapping	0.2	0.0	0.2	0.2	0.0	0.2
	Control Centre	1.4	0.0	1.4	1.4	0.0	1.4
	Call centre	1.0	0.0	1.0	1.0	0.0	1.0
	Stores	0.1	1.9	2.1	0.1	2.7	2.8
	Operational training	0.3	0.0	0.3	0.3	0.0	0.3
	Vehicles and transport	0.1	0.1	0.1	0.1	0.1	0.2
	Network policy	0.4	0.0	0.4	0.4	0.0	0.4
Business Support Indirects	HR and non-operational training	1.0	0.1	1.1	1.0	0.2	1.1
	Finance & Regulation	2.2	2.0	4.1	2.2	2.8	5.0
	CEO	1.4	0.0	1.4	1.4	0.0	1.4
	IT & telecoms (indirects only)	1.4	10.3	11.7	1.4	14.6	16.0
	Property (indirects only)	0.3	2.1	2.4	0.3	3.9	4.2
	Total	10.9	18.2	29.0	10.9	26.4	37.3

KPMG's analysis showed that the proportion of fixed and semi variable costs varied significantly between activities. Fixed and semi variable costs comprise more than 50% of the following activities: stores, network policy, HR and non-operational training, CEO, IT & Telecoms, Property.

		Fixed costs	Semi variable costs	Variable costs
Closely Associated Indirects	Network design & engineering	15%	20%	65%
	Engineering management and clerical support & Project management	3%	4%	93%
	System Mapping	13%	0%	87%
	Control Centre	37%	0%	63%
	Call centre	31%	0%	69%
	Stores	8%	92%	0%
	Operational training	4%	0%	96%
	Vehicles and transport	1%	1%	97%
	Network policy	100%	0%	0%
	Total	11%	8%	81%
Business Support Indirects	HR and non-operational training	52%	7%	41%
	Finance & Regulation	25%	23%	53%
	CEO	53%	0%	47%
	IT & telecoms (indirects only)	11%	81%	7%
	Property (indirects only)	9%	70%	21%
	Total	21%	50%	28%

KPMG's report estimated that the fixed cost uplift which Electricity North West should be afforded relative to other DNOs as a result of its single licence status is £10.5m per year, after adjustment for reductions that could potentially be achieved through outsourcing (2011-12 prices). The following table shows the fixed cost uplift identified by KPMG, by activity.

		KPMG estimate		Uplifted to 2012-13 prices	
		net distribution*	gross costs	net distribution	gross costs
		2011-12	2011-12	2012-13	2012-13
Closely Associated Indirects	Network design & engineering	0.8	0.8	0.9	0.9
	Engineering management and clerical support & Project management	0.4	0.4	0.4	0.4
	System Mapping	0.1	0.1	0.1	0.1
	Control Centre	0.7	0.7	0.7	0.7
	Call centre	0.5	0.5	0.5	0.5
	Stores	0.6	0.6	0.7	0.7
	Operational training	0.1	0.1	0.1	0.1
	Vehicles and transport	0.1	0.1	0.1	0.1
	Network policy	0.2	0.2	0.2	0.2
Business Support Indirects	HR and non-operational training	0.5	0.6	0.6	0.6
	Finance & Regulation	1.6	1.8	1.7	1.8
	CEO	0.7	0.7	0.7	0.8
	IT & telecoms (indirects only)	3.8	4.1	3.9	4.2
	Property (indirects only)	0.2	0.2	0.2	0.2
	Total	10.5	10.9	10.7	11.3

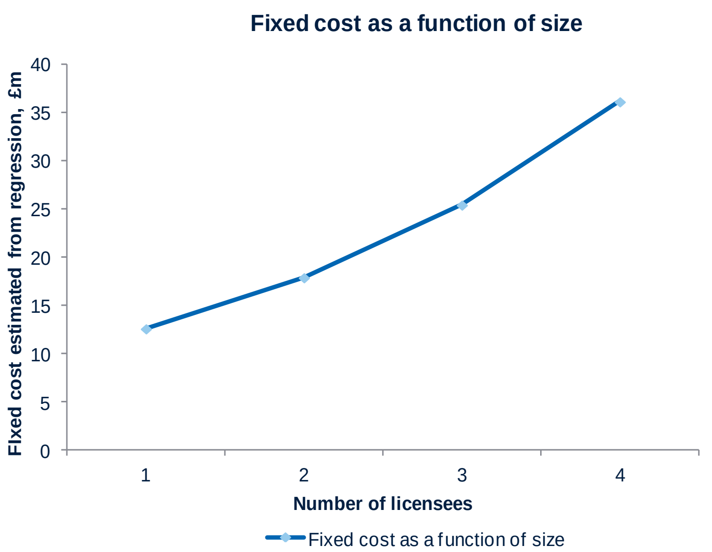
* Equivalent to 'Estimated Efficient Fixed Cost Uplift adjusted for non price control costs' in KPMG report

We used the results of KPMG's analysis in testing that our forecast costs represented an efficient level of costs for a single licensee group.

3.2 Econometric Assessment of Level of Fixed Costs - Oxera

We asked Oxera to test whether it was possible to assess the level of fixed costs incurred by companies of different sizes econometrically using a regression model containing the data submitted by DNOs in July 2013. The results of Oxera's analysis follow.

Ownership Group	Average Business Support Cost submitted over forecast (£m)	Average fixed cost estimated from the model (£m)
ENWL	36	12.6
NPG	42.1	17.9
SP	50	17.9
SSE	48.3	17.9
UKPN	91.9	25.4
WPD	105.3	36.1
Total	**373.6**	**127.7**



Oxera's results are somewhat counterintuitive as they suggest that more fixed costs are incurred in moving from a 3 DNO group to a 4 DNO group than is suggested between 2 and 3 DNO group. The opposite would be expected, particularly as the average size of WPD's 4 licensees is smaller than the average size of UKPN's licensees. This is possibly because of the small sample size involved and the fact that the sample includes only one single licensee, one 3 DNO group and one 4 DNO group. For this reason, we do not recommend that Ofgem uses econometric modelling to assess levels of fixed costs due to the sample size involved.

Using the fixed costs estimated from the regression model, Oxera tested the hypothesis whether fixed costs are proportional to the number of licensees operated by an ownership group. The hypothesis was rejected at the 1% level of significance. In other words, when the number of licensees increases from one to two, the fixed cost of the group increases by less than twice, demonstrating that smaller companies incur a higher level of fixed costs.

Further details of Oxera's analysis can be found in Appendix 3.

4. How Ofgem's Cost Assessment Analysis Considered Fixed Costs

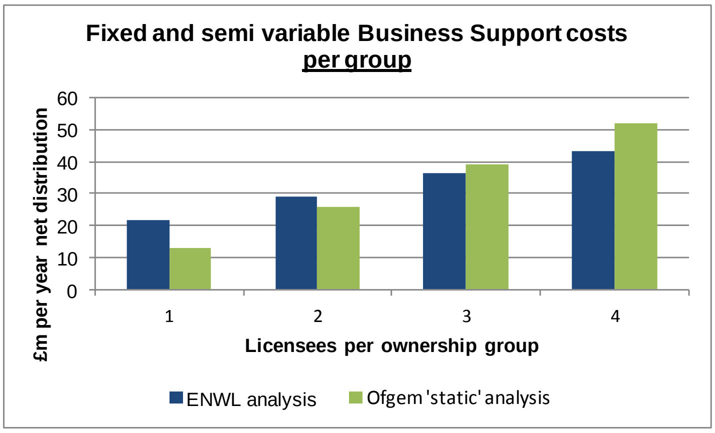
4.1 Business Support Analysis

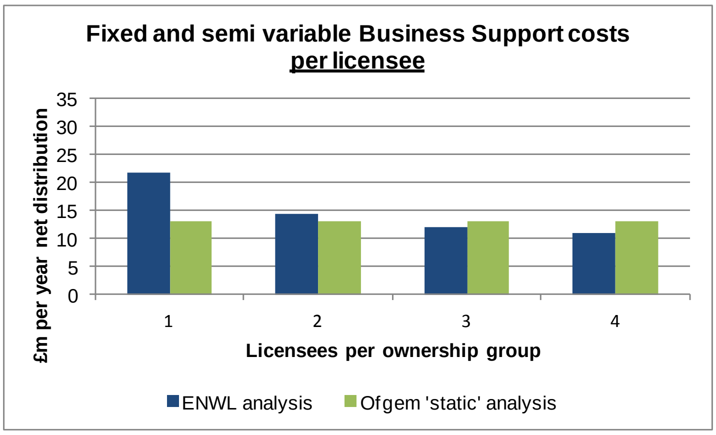
4.1.1 Ofgem's Approach

Ofgem's bottom up analysis of our proposed business support costs as part of its Fast Track decision suggested that efficient business support costs for Electricity North West are £177m (2012-13 prices, net distribution, eight year total, including real prices effects). Our plan included £255m of business support costs. Ofgem therefore suggested that our proposed business support costs were 44% higher than a modelled efficient level of costs.

As part of its analysis it made a normalisation adjustment to remove £13m per licensee from business support costs. In doing so, it effectively assumed that costs were fixed by licensee and no costs could be shared between companies.

The following graphs show how the level of fixed and semi variable costs removed in Ofgem's normalisation compare to the level identified in KPMG's analysis. We have extrapolated KPMG's analysis to show 3 and 4 licensee groups. It is clear that Ofgem's normalisation differs significantly from KPMG's and that at a licensee level (second graph), Ofgem's approach will particularly distort the efficiency results of single licensee groups.





4.1.2 Sensitivity Analysis of Ofgem's Approach

Ofgem's business support cost assessment model does not currently include a facility to remove different levels of fixed costs per group; it simply allows removal of the same value per licensee or per group.

We asked Oxera to undertake analysis to test the sensitivity of results of Ofgem's modelling to different assumptions in fixed cost normalisation, using the following scenarios:

- £13m per licensee – as in Ofgem's Fast Track analysis
- No fixed cost adjustment
- £23m per ownership group – twice KPMG's identified fixed cost uplift between a single and two DNO group

The results of Oxera's analysis show that Ofgem's business support analysis is hugely sensitive to its fixed cost assumptions, and that more appropriate assumptions would result in modelled efficient costs for Electricity North West being more than £77m higher.

Fixed costs - results

£m ED1 2012-13 prices		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Static	Efficiency %	-47%	-24%	29%
	Allowance	184.5	190.8	261.7
Monte Carlo	Efficiency %	-25%	-22%	6%
	Allowance	184.9	192.8	262.1

Fixed costs - variance

£m ED1 2012-13 prices		£13m per licensee (Ofgem)	No adjustment	£23m per Group
Static	Efficiency %	N/A	23%	76%
	Allowance	N/A	6.2	77.2
Monte Carlo	Efficiency %	N/A	3%	31%
	Allowance	N/A	7.9	77.2

The detailed results of Oxera's analysis can be found in Appendix 4.

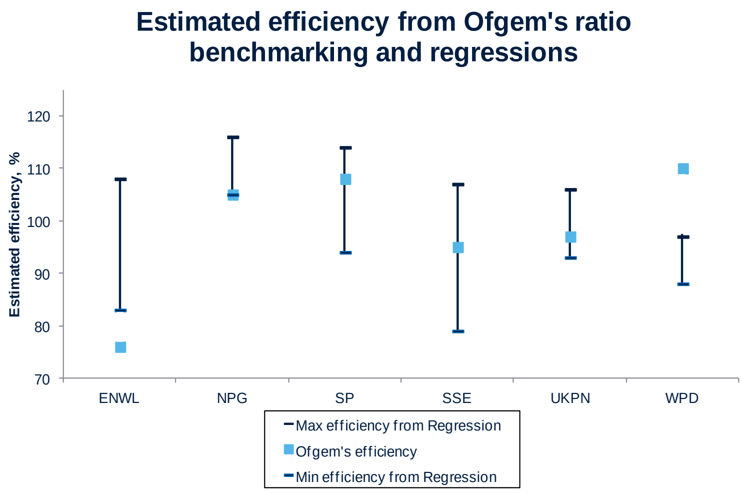
4.1.3 Alternative Regression Analysis

We asked Oxera to assess how the results from regression analysis differ from those of Ofgem's model.

Oxera developed a range of eight regressions based on combinations of

- Cost driver: Ofgem's Business Support composite and MEAV (driver for business support in Ofgem's activity drivers totex)
- Licensee and group based analysis
- Logarithms and levels

The results of its analysis are shown on the following graph.



In addition to demonstrating the sensitivity of results to the regression assumptions chosen, Oxera's results clearly demonstrate that the results obtained from Ofgem's model are outside of the range of results obtained from regression analysis.

Oxera's analysis included four ownership group based models. On average, these models suggest that Electricity North West's modelled efficient costs should be some £48m higher than Ofgem's analysis.

More details of Oxera's regression analysis can be found in Appendix 5.

4.1.4 Sensitivity Analysis to Ofgem's Approach

We asked Oxera to adapt Ofgem's business support model to allow a different level of fixed cost normalisation to be made depending on the number of licensees within the ownership group. Oxera used this model to remove a level of fixed costs determined econometrically via regression analysis, as described in section 3.2. If Ofgem had used this approach at its fast track decision the level of modelled fixed costs for Electricity North West would have been £25m higher.

Further details of Oxera's analysis can be found in Appendix 3.

4.1.5 Other Factors Affecting Ofgem's Assessment of our Business Support Costs

Ofgem's assessment of the efficiency of our business support costs is further distorted by three other issues:

- Analysis is distorted by Ofgem's removal of insurance costs from its models. This approach disadvantages companies such as Electricity North West that included very efficient forecasts of insurance costs.
- A spreadsheet error in Ofgem's business support model resulted in negative costs being modelled for some companies and artificially reducing benchmark costs. As this error affected all DNOs it was partially corrected via Ofgem's upper quartile translation.
- A spreadsheet error in Ofgem's aggregated cost assessment model resulted in the results from the business support model being inappropriately treated as gross costs. As this error affected all DNOs it was partially corrected via Ofgem's upper quartile translation.

Annex 14 provides more details of these issues.

4.1.6 Summary

We strongly believe that the evidence presented here demonstrates that Ofgem's assessment of our business support costs as part of its Fast Track decision was materially distorted by an inappropriate assumption regarding fixed cost normalisation. Different alternative modelling approaches inevitably suggest different results, but all suggest material increases to the level of efficient business support costs above that assumed by Ofgem.

4.2 Closely Associated Indirect Analysis

Ofgem's bottom up analysis of our proposed closely associated indirect costs as part of its Fast Track decision suggested that efficient closely associated indirect costs for Electricity North West are £370m (2012-13 prices, net distribution, eight year total, including real prices effects). Our plan included £336m of closely associated indirect costs. Ofgem therefore suggested that our proposed closely associated indirect costs were 9% lower than a modelled efficient level of costs, ie our costs forecasts are better than Ofgem's modelled costs.

Ofgem's assessment of closely associated indirects was generally based on regression by licensee. Ofgem included no group based regressions. We believe that it would be appropriate to incorporate group based regressions for those elements of cost that include substantial fixed and semi variable costs, such as network design & engineering, network policy, stores, control room and call centre, to ensure that account is taken of costs that can be shared between companies of the same group. Appendix 2 provides details of KPMG's assessment of fixed and semi variable costs associated with closely associated indirects.

4.3 Overall Sensitivity Analysis

Ofgem's published Fast Track assessment document 'Assessment of the RIIO-ED1 business plans' states that "*Whilst our central view does not include any adjustment for ENWL's view of 'fixed costs', our sensitivity analysis with 'fixed costs' included shows that ENWL is still above our overall fast-track cost assessment benchmark."* The report goes on the say that this sensitivity analysis was undertaken "*on the basis of ENWL's view of 'fixed costs*'".

Ofgem's overall cost assessment results, adjusted for monetisation of cost of equity and outputs, suggested that our costs were £77m above Ofgem's benchmark (8 year value, 2012-13 prices, net distribution). KPMG's view of equivalent annual fixed cost uplift, as included in our July 2013 plan, is £10.7m per year ie £85m over 8 years. We therefore do not understand how Ofgem has concluded that our costs are above its cost assessment benchmark when fixed costs are included.

We have repeatedly asked Ofgem to share its sensitivity analysis to allow us to understand how it reached this conclusion, but it has not shared the analysis with us. Without being able to review Ofgem's analysis, we can only assume that Ofgem made an error in how it undertook its fixed cost sensitivity.

4.4 Alternative Approaches For Assessing Slow Track Companies

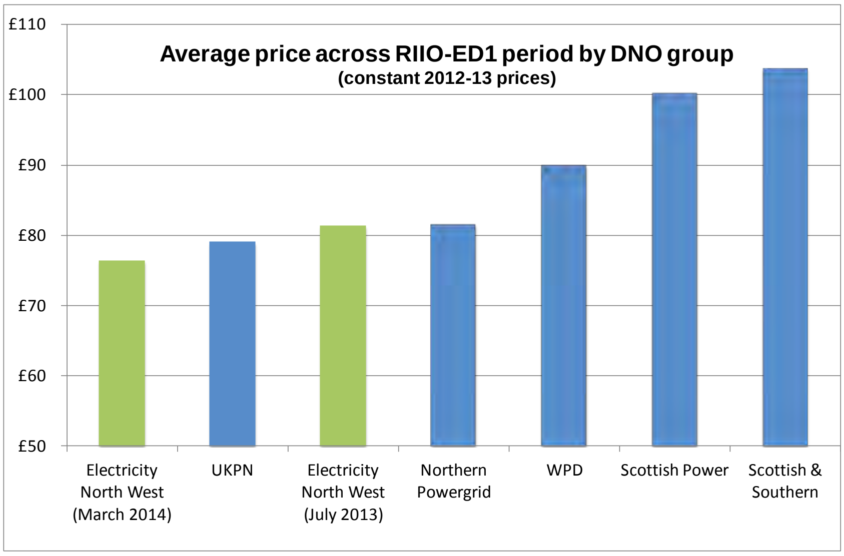
It is essential that Ofgem's cost assessment methodologies for business support indirects and closely associated indirects take account of the extent to which fixed costs can be shared by companies in the same ownership group. Annex 14 outlines in more detail our proposals for how cost assessment approach for Slow Track companies should be different to that used to assess Fast Track companies.

We note that the two largest DNO ownership groups, UK Power Networks and Western Power Distribution, have both proposed group-based cost assessment approaches for the assessment of some business support indirects and closely associated indirects. We believe that this adds further evidence to support both the fact that fixed costs can be shared by companies in larger groups and that the most appropriate cost assessment tools for these activities are those based on ownership group analysis.

5. Why It Is Appropriate For North West Customers To Pay For Fixed Costs

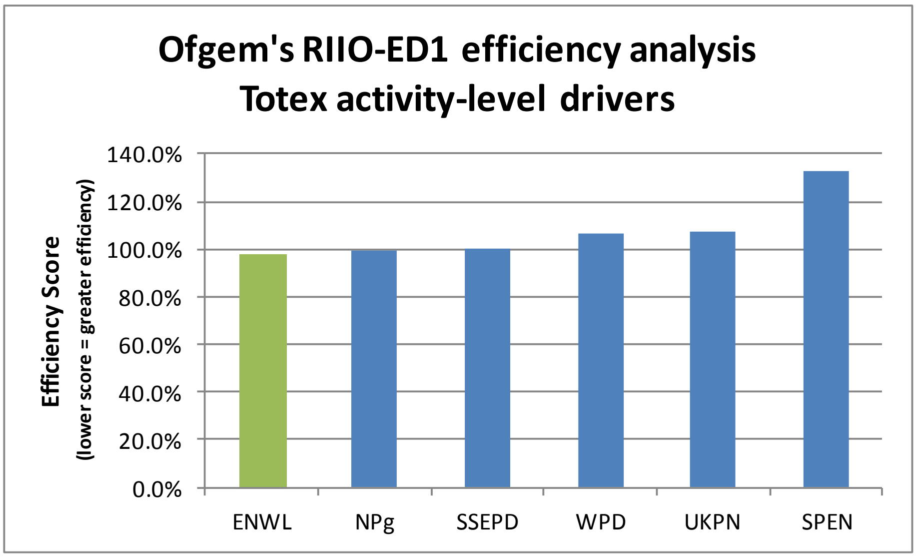
5.1 Providing Excellent Value for Money

Overall, we are confident that our plan offers excellent value for money for our customers and that the benefits in other parts of the plan outweigh these higher costs. Despite the inclusion of these costs our customers will pay some of the lowest prices for electricity distribution in Great Britain during the RIIO-ED1 period. We have compared the prices in our plan (using Ofgem's Plan-on-a-Page format) with the information available from all the other DNOs (Plan-on-a-Page) in July 2013 to produce the graph below.



Source: All DNOs plan on a page publications, July 2013

This shows that our prices were the second lowest of any DNO group and have reduced significantly. This is not a surprise as our base revenue is over £76m lower than in our previous business plan submission in July 2013. Last year Ofgem assessed the total costs of each DNO's business plan and its analysis showed that our total costs are amongst the lowest of any DNOs in Great Britain. This efficient cost base feeds directly into lower prices for our customers.



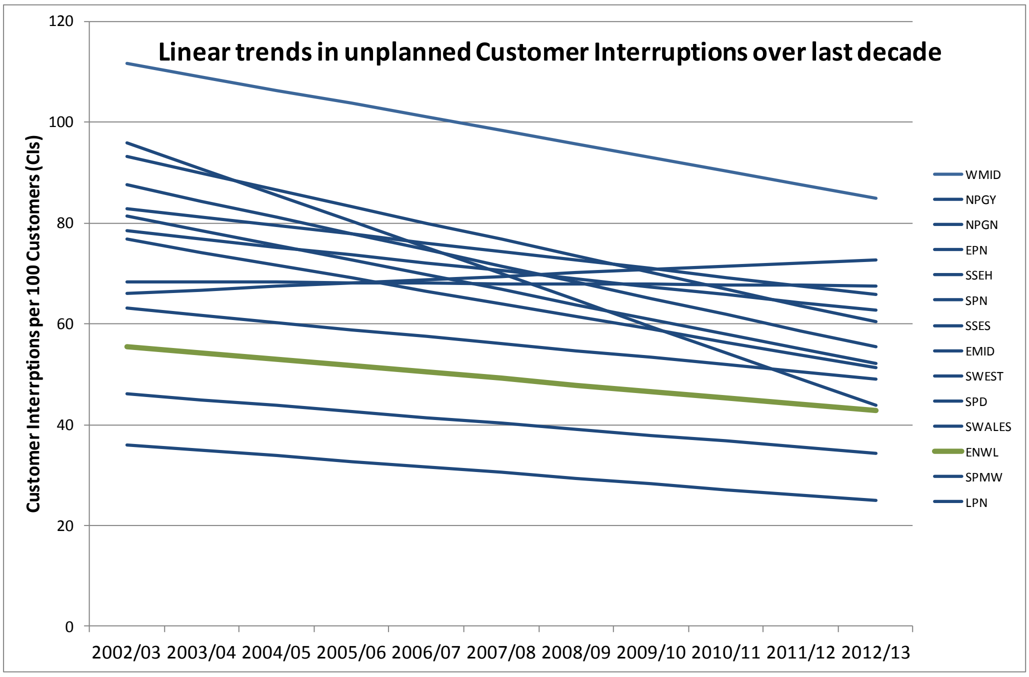
Source: Ofgem, RIIO-ED1 business plan expenditure assessment - methodology and results, December 2013

5.2 Benefits of Electricity North West

Electricity North West is entirely focused on delivering electricity to the five million people who live and work in the North West of England. We are not part of a larger corporate group, we do not get distracted by operations in any other parts of the energy supply chain. We simply concentrate on serving our customers in the best ways possible, day in and day out. We have always been leaders in some fields in our industry and since we separated from a larger corporate group in 2007 we have been steadily improving our performance in every aspect of our business.

5.2.1 Quality of Supply Leaders

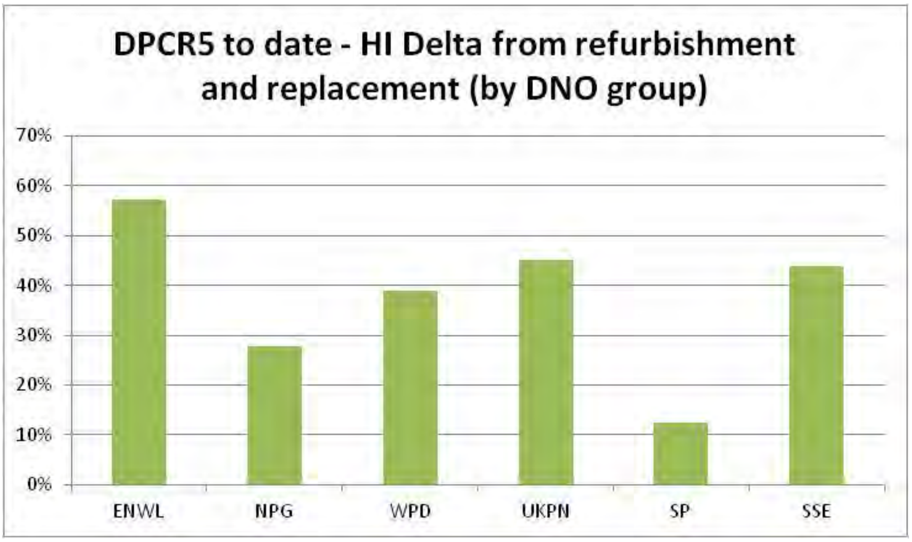
The quality of supply experienced by customers connected to our network has consistently been one of the best in the country since privatisation and, since the introduction of standard measurement in 2002 has been shown to be consistently in the upper quartile. This means that over the last decade, the people in the North West have experienced some of the most infrequent and shortest power cuts in the whole of Great Britain. Our network is inherently resilient and we ensure it stays that way through efficient maintenance and asset renewal. Our performance has steadily improved as we have developed and implemented a wide variety of 'smart' technologies on the network including the deployment of widespread remote sensing and control, coupled with artificial intelligence and a self-healing capability into the control room.



Source: Ofgem

5.2.2 Investment Delivery Leaders

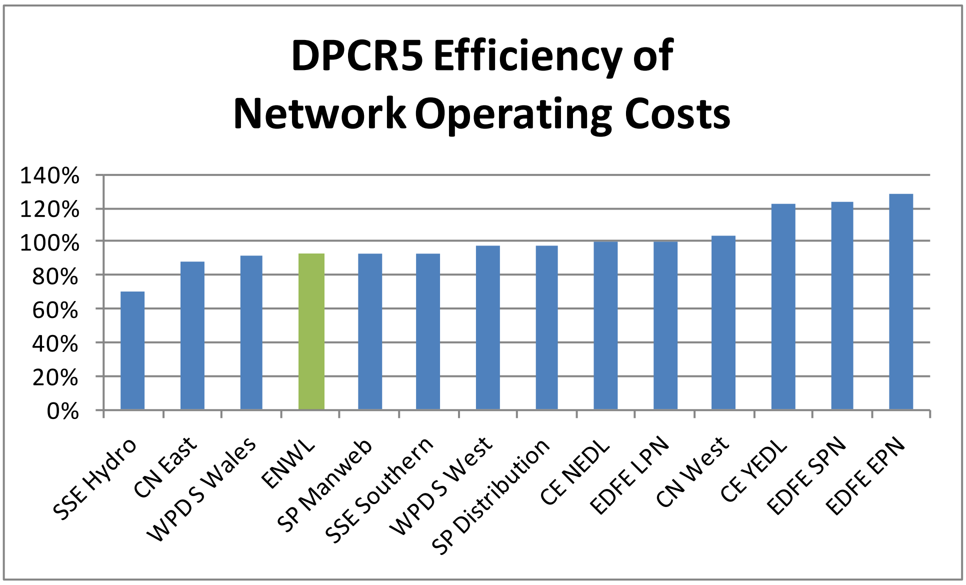
Unsurprisingly for the birth place of the industrial revolution, the North West contains some of the oldest electricity network in the country. This could have presented a risk of more frequent power cuts as old assets fault or a high asset renewal bill to our customers. To manage this risk Electricity North West has developed world-leading asset management techniques and technologies to ensure we spend our customers' money as wisely as possible. These techniques determine the best things to do and in more recent years we have also demonstrated our leadership in the efficient delivery of these projects. This is now demonstrated by our leading performance against the output metrics looking at improvements in asset health that we have helped Ofgem introduce for the DPCR5 period. This shows that in the first two years of DPCR5, we delivered a higher proportion of our overall DPCR5 HI target than any other DNO group. The graph below shows that we are well ahead of scheduled having completed nearly 60% of our programme in the first two of the five year programme.



Source: Ofgem

5.2.3 Cost Reduction Leaders

In 2009, as Ofgem set the last price control review, we were rewarded as leaders in determining both the lowest unit costs of capital projects of any DNO in Great Britain and recognised as leaders in operational efficiency. We have continued to deliver efficiently for our customers and to set benchmarks for the whole industry. Ofgem's initial assessment of our previous business plan for the RIIO-ED1 period indicated that we remained a unit cost leader and an operating cost leader. Additionally, Ofgem's assessment shows that our total cost base is now one of the lowest of all DNOs.



Source: Ofgem, DPCR5 Final Proposals - Allowed revenue - Cost assessment appendix, December 2009

5.2.4 Innovation Leaders

We have achieved this performance for our customers not only by working harder, but also by working smarter. Electricity North West has developed a culture that encourages new ideas and new approaches. This has been inspired by the successes we have had in the asset management area and has been expanded to cover all areas of our business. Innovation drives our excellent quality of supply performance, our low unit costs and contractor costs, our tree-cutting leadership and our stakeholder engagement. Our strength in this area is perhaps best measured by our performance in Ofgem's Low Carbon Networks Fund innovation competition where we have been the only company to successfully win an un-conditional project award in each of the last three years.

Our innovative approach has been applied to the challenges facing our industry as we move to a low carbon economy. We are developing exciting new techniques and technologies to tackle these challenges that have significant benefit for our customers. These include our new Capacity To Customers (C_2C) Demand Side Response contracts and our Smart Street energy cost minimisation approach. As a result of our innovative approach, our customers have benefitted from the largest payback on innovation investment of any DNO (£133m benefit for £26m investment) and the largest smart grid discount in RIIO-ED1 plans of any DNO at over £82m.

Our leadership in our industry demonstrates that our customers benefit considerably from being served by Electricity North West. Electricity customers connected to our network receive some of the best quality of supply for some of the lowest costs of anywhere in the country. Their service is provided by an effective business focussed solely on the North West that has a proven track-record in innovation, enabling a rapid and effective response to any new challenge that might arise.

5.3 Our Role as a Comparator

In our industry, it is important to have a number of different owners and operators running the distribution businesses. This means that new ideas and approaches are developed by a good number of different management teams and enables their performance to be compared to identify and share best practice.

In its policy statement on mergers, Ofgem flags a number of issues associated with the benefits of different DNO groups. Ofgem states that:

> *"the number of independent groups within a sector brings significant benefits to consumers in terms of the ability it gives Ofgem to set effective price controls."*

By remaining independent from the other five DNO groups Electricity North West provides a valuable comparator that provides benefits to the people of the North West and to DNO customers across the country.

Ofgem lists a number of benefits of independent distribution companies, including:

- *"The more independent companies that we have to compare the more likely it is that one of them will reveal information that will allow us to set allowed revenues at an efficient level for all companies and/or that will support us in setting higher quality standards"*

- *“The more information that we have from independent sources then the more confident we can be in our cost assessment work meaning that we do not need to err on the side of caution”*
- *“These independent groups ... are compared against each other ... by investors and consumers as well. This creates competition between these management teams to become the leading performers in terms of efficiency and service quality. The more independent management teams there are competing to be the leading company the fiercer this competition is and consumers benefit from this through improvements being made more quickly than they otherwise would in the absence of that competition”*
- *“This is the essence of comparative regulation – Ofgem needs to use regulatory tools to try and replicate the competitive pressures that do not naturally exist in monopoly businesses. These competitive pressures are much stronger the more independent companies that we have in a sector”*
- *“Mergers ... may reduce the diversity in management approaches ... [and] the number of opinions/views within the sector which can be very useful for making progress in introducing new ideas or generally in policy development itself”*
- *“There are significant qualitative benefits where Ofgem is able to make comparisons between companies in terms of the ideas and policies that they are proposing”*
- *“There may be scope for a group that controls a significant share of the market to ‘game’ this benchmarking by allocating costs in a particular way between its licensees that maximises its total allowed revenues to the detriment of consumers”*
- *“There may also be issues of comparability between network groups if their scales vary significantly. A large group would also have a significant impact on any benchmarks that we set”*

5.4 Appropriateness of Including Fixed Costs in our Business Plan

Overall, we are confident that the benefits to north west customers of us remaining a single licensee and continuing to offer leading service for low costs, combined with the benefit to all customers in Great Britain of being an extra comparator that Ofgem will use to set stretching targets, more than outweighs the relatively small additional costs associated with being a single licensee. We therefore believe that our proposition for customers to fund the slightly higher costs in this area is well justified.

6. How Customers Will Be Protected From Any Change In Ownership Structure

We accept that single licensee status is not an inherent characteristic and that it is possible that during the course of RIIO-ED1 our status could change.

If we become part of an ownership structure that includes one or more other DNO licensee operating in Great Britain (either because our current owner purchases another licensee or because we are sold into a group that already includes a DNO licensee) we agree that an adjustment should be made to our cost baselines for fixed costs to ensure that any fixed cost allowance that we no longer need is returned to customers.

We propose to introduce a mechanism, to be set out in our distribution licence, to ensure that an appropriate adjustment can be made to our allowed costs. This adjustment would effectively reverse our baseline costs for all or part of the fixed costs that were assumed in our RIIO-ED1 baseline costs at Final Determination. Assuming that Ofgem accepts our proposal, this would be capped at either £10.7m pa (KPMG's identified fixed cost uplift) or the level of company specific adjustment made by Ofgem (if that amount is lower than £10.7m pa). We observe from data following in recent consolidations that it takes some time for savings to be made and propose that adjustments would be enacted from 12 months after the finalisation of any transaction that leads to us being part of a wider group. Any savings that we are able to make in the first 12 months following any transaction would be shared with customers via the routine efficiency sharing mechanism.

In order to ensure that any changes associated with this mechanism are predictable to suppliers and can therefore be passed through to customers, we propose that adjustments would be proposed and made at times set out for other uncertainty mechanisms in May 2019 and at the end of RIIO-ED1 period. These adjustments would take account of any transactions that occurred before those dates so that customers are fully compensated.

We will work with Ofgem to develop the required licence condition and associated financial handbook chapters and price control financial model modifications to achieve this. A draft licence condition is included as Appendix 6.

7. Conclusion

Electricity North West is the only Distribution Network Operator (DNO) that is in an ownership structure that does not contain another DNO. As a consequence of this, we incur a level of fixed costs that is higher than other DNOs (because the other DNOs can share costs with companies in the same group).

We have undertaken analysis, supported by KPMG, to assess the level of fixed costs that a single licensee would incur above the level that would be expected of DNOs in an ownership group that included two DNOs. KPMG's report estimated that the fixed cost uplift which Electricity North West should be afforded relative to other DNOs as a result of its single licence status is £10.5m per year (2011-12 prices).

Ofgem's cost assessment analysis undertaken as part of its Fast Track decision did not take account of the fixed costs of being a single licensee. This resulted in the level of business support costs included in our July 2013 plan being assessed as being inefficient.

We believe that Ofgem made an error in how it undertook its fixed cost sensitivity.

Oxera has undertaken analysis for us that considers alternative assumptions within Ofgem's business support models. Oxera has also considered alternative modelling approaches such as regression analysis. This analysis demonstrates that Ofgem's assessment of our business support costs as part of its Fast Track decision was materially distorted by an inappropriate assumption regarding fixed cost normalisation; alternative models suggest much higher modelled efficient costs for Electricity North West.

Oxera has also undertaken analysis, based on the data provided by DNOs in July 2013, that demonstrates that when the number of licensees increases from one to two, the fixed cost of the group increases by less than twice, demonstrating that smaller companies incur a higher level of fixed costs.

Our analysis suggests that Ofgem's analysis underestimated allowances for fixed costs by between £25m and £77m. Different alternative modelling approaches inevitably suggest different results, but all suggest material increases to the level of efficient business support costs above that assumed by Ofgem. The low end of this range on Oxera's econometric assessment of fixed costs that are somewhat counterintuitive and probably under-estimate fixed costs.

Overall, we are confident that the benefits to north west customers of us remaining a single licensee and continuing to offer leading service for low costs, combined with the benefit to all customers in Great Britain of being an extra comparator that Ofgem will use to set stretching targets, more than outweighs the relatively small addition costs associated with being a single licensee. We therefore believe that our proposition for customers to fund the slightly higher costs in this area is well justified.

We accept that single licensee status is not an inherent characteristic and that it is possible that during the course of RIIO-ED1 our status could change. If we become part of an ownership structure that includes one or more other DNO licensee we agree that an adjustment should be made to our cost baselines for fixed costs to ensure that any fixed cost allowance that we no longer need is returned to customers.

8. Appendices

The following documents are attached as appendices to this annex

Appendix 1	KPMG - Estimating a fixed cost uplift allowance for RIIO-ED1
Appendix 2	KPMG - Outsourcing suitability assessment
Appendix 3	Oxera - Econometric fixed cost estimation revised Monte Carlo ratios
Appendix 4	Oxera - Analysis of Business Support Costs
Appendix 5	Oxera - Business Support regression results
Appendix 6	Draft fixed cost adjustment licence condition

[These appendices contain commercially sensitive or personal information and have been redacted from public domain versions.]