UK Power Networks

Business plan (2015 to 2023)

Annex 10: Smart Metering

March 2014

“A reliable... an innovative... and the lowest price electricity distribution group.”

UK Power Networks
Delivering your electricity

Contents

Document History

Version	Date	Revision Class	Originator	Details	Section Update
1.01	14/01/2014	Minor	Adrian Searle	Added version control table at the beginning of the document.	N/A
1.02	21/02/2014	Major	Adam Rielly	Updated the EPN, LPN and SPN RIGS data cost tables to reflect revised Direct and Indirect costs	1.4 Cost Summary tables 1 and 2
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1.02	21/02/2014	Minor	Adam Rielly	Added a comment to support the increase in DCC Fixed Costs allowance	2.1 Purpose and structure
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1.02	21/02/2014	Major	Adam Rielly	Revised the DCC Fixed cost pass-through profile to reflect the latest DCC view on Fixed cost per meter	6.4 Table 9 DCC Fixed and variable costs summary
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1 Executive summary

1.1 Context

The Government has mandated the rollout of smart gas and electricity meters to all domestic and non-domestic customers by the end of 2020. This is a major national change programme that will involve visits to every premise in the UK and the installation of more than 100 million devices over a five year period.

The rollout of smart meters will play an important role in Great Britain's transition to a low-carbon economy, and help us meet our long-term challenges in ensuring an affordable, secure and sustainable energy supply. They will provide real-time information on energy usage and accurate billing, helping consumers to target their usage and save money; they will enable the introduction of more sophisticated energy management, with Time-of-Use Tariffs and load shifting and they will pave the way for the smart grid and the network of the future.

The rollout is Supplier-led to maximise the potential for consumer benefits, but has significant dependencies on and opportunities for, Distribution Network Operators (DNO). These are:

Dependencies

- DNO Interventions: Suppliers and their agents periodically identify a meter installation where there is a technical problem with the service equipment which requires a DNO to undertake remedial work. These are typically identified during a meter replacement. The intensive rollout is likely to identify these earlier, leading to a significant expansion in these DNO interventions. Ofgem has indicated a core allowance of 2% of meter installations requiring an intervention. The business model will need to be able to address these efficiently and effectively.
- Industry Interface and Income Management: There are three broad areas of potential change: core systems such as registration will require modification to support smart meter data and flows; the Smart Energy Code (SEC) will require support and administration; the availability of half-hourly data may generate different billing requirements.
- Security and Privacy: access to the meter and provision and management of data is subject to stringent security and privacy requirements. The DNO must adhere to these.
- Data Communications Company (DCC) costs: The DNO is responsible for a fixed fee per meter point per year for the provision of DCC services and for transactional fees for optional services. The fixed fee will be treated as pass through until the end of mass rollout, 2020/21. Thereafter it will be funded by business benefit. Transactional fees should be funded by business benefit.

Opportunities

- Improved real-time data – Fault Management and Customer Service enhancements. The provision of real-time data on faults via the 'last gasp' facility and the ability to remotely test meter energisation status offer the opportunity to significantly improve fault management performance and customer service. It will be possible to identify and target faults more quickly and to provide the customer with significantly enhanced information and a faster response.
- Improved asset and performance data – Network Condition and Planning: The provision of detailed usage information from meters across the network offers the opportunity to significantly improve network planning. It will afford much better targeting of Low Voltage (LV) refurbishment, should enable the avoidance of additional development to support some new connections and help reduce losses.
- Improved real-time control – supporting the future network: the combination of real-time and asset data with greater real-time control, will pave the way for the network of the future in ED1. It will provide the information and capability to support expansion of low carbon technologies (LCT) and Time-of-Use Tariffs. There will be the ability to undertake Active Network Management (ANM) and further avoid the need for network reinforcement/d new investment. Smart meters will pave the way for a full smart grid in ED2.

1.2 Key principles

UK Power Networks has adopted the following key principles in determining our strategy for smart metering:

- The interests and experience of the customer are paramount. Work undertaken during ED1 must create a good customer experience and customer benefits must be realised early where possible, to help encourage positive adoption of smart metering.
- Smart metering will yield data and functionality that provides a significant opportunity for business benefits and these opportunities must be seized.
- Smart metering provides the vanguard in moving the UK distribution networks towards a smart grid, capable of supporting load shifting, pervasive Low carbon technologies and active network management. Investment must be made to take advantage of these opportunities in ED1 and provide a sustainable platform to maximise opportunities in ED2.
- Smart metering provides a new infrastructure that benefits not just DNOs, but customers, Suppliers, other participants and GB plc. All benefits must be sought and analysed, not just those that accrue to UK Power Networks.
- To measure these principles, we will aim to meet or exceed the benefits set out in the ENA's paper 'Analysis of Network Benefits from Smart Meter Message Flows Interim Review (Phasing and Categorisation)[1] and seek wherever possible to meet the benefits that can be distilled from the Department of Energy and Climate Change (DECC) Impact Assessment (IA)

1.3 Business model changes

UK Power Networks has considered whether the existing business model is best placed to support the challenge and opportunity of smart metering, or whether changes are required. The Smart Meter Readiness Programme has been established by UK Power Networks in order to plan, design, coordinate and programme manage the delivery of strands which will ensure a smooth roll out of smart meters by Suppliers as well provide business and customer service improvements. The following details the approach which has been adopted.

Interventions

We have based our Interventions approach on Ofgem's estimate of a 2% intervention rate. For Eastern and Southern regions, we have applied the 2% to the number of meters. For the London region, it is important to note that we have applied the rate to the number of services, reflecting the significant number of multi-storey properties in London. There are therefore less interventions but of greater rating and complexity in London, partially causing a much higher cost per intervention.

Based on the 2% rate, an average of 25,000+ smart meter installation related interventions per year (average through rollout period) may need to be undertaken. These must be carried out efficiently and effectively with trained staff who deliver a good customer experience and in a safe manner.

The Smart Meter Readiness Programme will establish the approach, processes, contractor strategy, recruitment and planning. Once established the business will be primarily managed through the existing three regions. This will: maximise the opportunity for efficient linkage with other forms of work; facilitate the transfer of business knowledge, mentoring and leadership from existing staff; encourage commitment to the company and help train staff for post-rollout careers. A mix of direct and contractor labour will be adopted to match a 2% intervention rate; this will vary region by region, according to existing practices and the availability of skilled resources. Direct recruitment will provide UK Power Networks with a new skilled labour force ready to cover workforce renewal and the new challenges of distributed networks impacted by LCT in ED2, while gaining the benefits of the marketplace and reducing the risk of resource shortages.

Recruitment and training plans will be put in place in the summer of 2013, alongside a retention strategy to insulate UK Power Networks from market competition. A contractor partnering strategy will be established. Existing working practices and contracts will be reviewed to identify best practice and ensure that is implemented across all regions.

New innovative ways of working will be sought, with a particular focus on safe live working to minimise costly and customer disruptive excavations. Constructive relationships will be established with Suppliers, to bring forward work wherever possible and maximise the information available, such that work can be planned to maximise efficiency and reduce customer impact.

Fault Management and Customer Service

We will take benefits of smart data early, particularly in the use of energisation checks to avoid nugatory visits. As more smart data becomes available, we will utilise this in our core fault management processes. We will review our overall business model, in particular the use of Distribution Supply Technicians (DST) to undertake site checks prior to crew dispatch. We will assess changes to the business model to support storm situations.

We will significantly improve the customer experience during fault situations. We will commence a move of our customer service operations from 'inbound reactive' to 'outbound proactive'. We will use the information available to maximise the speed and quality of information available to the customer, winning their trust and paving the way

[1] ED1 & ED2 Network and Smart Grid benefits arising from smart meter data and functionality

for reduced fault calls in the latter part of ED1 and throughout ED2. In conjunction with the UK Power Networks Transformation programme, we will identify and implement pro-active mechanisms of communicating with the customer to provide information on faults and rectification progress. This will help deliver a step change in business performance ready for ED2.

Network Operations, Planning and the Path to the Smart Grid

There will be limited changes to the business model during ED1. We will focus during this period on accumulating smart data to drive our greater understanding of the network. Towards the end of mass rollout, we will acquire sophisticated modelling tools and establish a small team to assess and optimise the use of the data. Such tools and data are expected to significantly enhance the capabilities of the design and planning function and facilitate in a controlled manner (with regard to supply quality) the mass deployment of LCT and the move to smarter networks. This will predominantly impact ED2, but may generate some changes during ED1.

We will actively work with Suppliers and seek opportunities to exploit the potential of Time-of-Use tariffs and load shifting. We will determine whether this should be a separate unit, or integrated with the core business.

Other areas

Other areas will only require small increases in operational cost, or minor change to the model.

1.4 Cost summary

UK Power Networks has assessed each area of cost and sought ways to optimise spend, consistent with delivering a quality consumer experience and the overall benefits. The costs are summarised in the Table 1. Costs are elaborated in each relevant section in this document.

Table 1 Programme overall cost summary

Area	DPCR5	ED1	Comment
Interventions	£1.8m	£48.8m	Establish a workforce and carry out additional smart meter call outs and interventions
Indirects (inc. training)	£1.0m	£6.2m	Associated work management and for additional Smart Meter Interventions.
Industry interface and income management	£0.2m	£0.6m	Support additional data queries and the Smart Energy Code (SEC)
Call centre	-	£0.4m	Additional agents to manage the Smart Meter call outs.
Network Condition and Planning	-	-	
DCC Fixed charge	£1.9m	£12.3m	Based on 7.7m meters, rising from 12p to 20p per meter per year
DCC transaction costs	-	£1.9m	Energisation checks and asset data
IT Costs	£6.3m	£22.3m	Mandated change and building a platform to support smarter networks
Total	£11.2m	£92.5m	

We have made the following assumptions about pass-through of costs in our submission.

Table 2 Pass-through cost summary

Area	Pass-through	Borne by UK Power Networks	Comment
Interventions	£50.6m	-	Costs directly arise from the programme
Indirects (inc. training)	£7.2m	-	Costs directly arise from the programme
Industry interface and income management	£0.8m	-	Costs directly arise from the programme
Call centre	£0.4m	-	Costs directly arise from the programme
Network Condition and Planning	-	-	
DCC Fixed charge	£11.1m	£3.1m	Pass-through until 2020/21, thereafter funded by business benefit
DCC transaction costs	-	£1.9m	Ofgem has indicated these need to be funded by business benefit and our submission reflects this. However, we note that significant additional information collection could yield additional benefits for GB plc and would seek to discuss funding of that with Ofgem during ED1.
IT Costs	£23.0m	£5.6m	We have assumed all mandated change is funded by pass-through. For the data warehouse and network modelling tools to support enhanced network management, we have assumed that 75% is pass-through. This is in line with the DECC IA, that assumes 25% of the benefits accrue to DNOs and 75% to GB plc
Total £119.1m	£93.1m	£10.6m	

1.5 Benefit summary

UK Power Networks has undertaken a rigorous approach to identifying and quantifying potential benefits. We have reviewed the benefits in the DECC IA and in the ENA submissions to the programme to identify the applicability and value to UK Power Networks. We have further sought to identify additional benefits and to ensure smart meter opportunities are fully fed into our other corporate initiatives. We have assessed the benefits to other parties, for example consumers and Suppliers, as well as to ourselves. The benefits are shown in the table over. In summary we estimate that during the ED1 period we can deliver:

- A total of £67.2million benefits for all parties against the DECC IA[2] estimate of £107million and the ENA estimate of £67million. (based on the paper 'Analysis of Network Benefits from Smart Meter Message Flows Interim Review[3];
- Benefits of £33.8million to the UK Power Networks business; £17.5million is already included in our core RIIO plan; £16.3million are additional benefits
- £13.9million of direct benefits to consumers, through reduced CMLs and lower bills for new connections from expected reduced network reinforcement requirements on low voltage networks

In addition to these financial benefits, we believe we can deliver substantial qualitative benefits to consumers, in particular proactive targeted messaging in fault situations. We can also position the business ready to address the opportunities of the network of the future at the start of ED2.

We note that the DECC and ENA benefits assume a rollout end date of 2019 and hence overstate the benefits available, since rollout will not now complete until 2020. The UK Power Networks projected benefits hence compare very favourably.

[2] The DECC IA is difficult to interpret given it primarily uses total NPV benefit. We have used the per meterpoint figures in the 2012 IA, amended to reflect updated commentary in the January 13 IA.

[3] The ENA paper (ref above) sets out totals for ED1. We have assumed the UK Power Networks should deliver 28% of that benefit based on our meter population

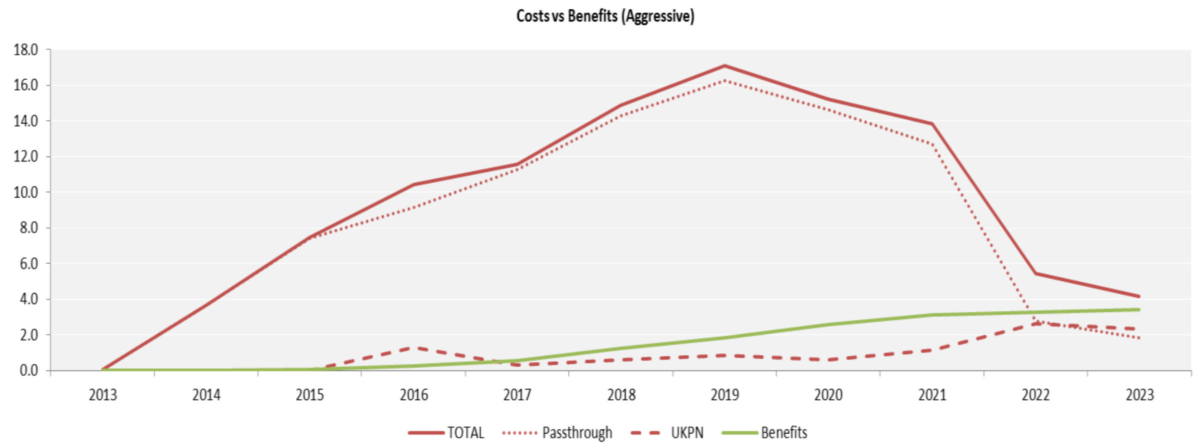
Table 3 Benefits summary against the DECC IA and ENA proposals

Benefit	Value in ED1					Comment
	DECC IA	ENA	UK Power Networks RIIO Plan	UK Power Networks New	Other beneficiaries (customers & suppliers)	
Reduced Losses	£26m	£28m			£19.5m	Reduced losses will accrue to Suppliers
Investment Decisions	£20m	£5.5m		£1.5m		Current projected low levels of reinforcement mean that the comparable DECC/ENA benefit cannot be fully realised
New Connections		£4.5m			£3.5m	Benefit will accrue to new customers as connections are requested through reduced network reinforcement costs
Avoided voltage investigations	£7m	nil				In the short term these will increase as smart metering will provide greater visibility. In the long term they will decrease
Active Network Management (ANM)	nil	£5m	£4m			Our RIIO plan already includes the use of ANM to reduce investment
Load shift/ToU	£2m	£18m	£13.5m			Our RIIO plan already includes the use of load shift to reduce investment. Note this is dependent on Suppliers.
Energisation status	Qualitative	In other		£11.1m		Energisation checks will avoid 11,000 nugatory visits per annum
Reduction in CML	£18m	£6m			£10.4m	This assumes the ENA proposal of an average 10 minute per fault (low voltage) reduction and customers willingness to pay research
Reduced fault opex	£28m	nil		£3.7m		
Reduced calls	£6m	nil				We concur with DECC that calls will reduce in the long term, but believe this trend will not appear until ED2
Total by party			£17.5m	£16.3m	£33.4m	
Total all parties	£107m	£67m	£67.2m			

Overall Financial Summary

The graph below indicated the overall position for UK Power Networks. The graph includes all costs incurred, separated into pass-through and business funded costs. Only those benefits that accrue to UK Power Networks are included.

Figure 1 Overall financial summary



The key conclusions, based on the pass-through assumptions set out above, are:

- The cost of supporting smart metering is £103.7million, of this:
  – £93.1million is assumed pass-through
  – £10.6million is assumed to be borne by business benefits
- The total benefits accruing to UKPN are £33.8million
- From the end of ED1, smart metering is broadly neutral to UK Power Networks.

2 Introduction

2.1 Purpose and structure

This document comprises UK Power Networks' submission to Ofgem for RIIO-ED1 with regard to the impact of smart metering on the UK Power Networks business. The document is structured as follows:

- The preceding Executive Summary, summarising the key dependencies on, and opportunities for, DNOs; our strategic response and the overall costs and benefits
- This introduction
- Four sections outlining our response on the key dependencies:
  - DNO Interventions
  - Industry interface and income management
  - Privacy and security
  - Interaction with the DCC
- Two sections outlining our response on the key opportunities of smart metering:
  - Fault Management
  - Network Planning, Operation and the path to the Smart Grid
- A section drawing together the IT impacts and requirements across the business. Note that each section describes its own IT impact and costs; this is drawn together here, but costs are not additional.
- A section bringing together uncertainties across smart metering and their impact.

Each of the dependency/benefit sections is divided into broadly the same sub-sections for ease of navigation:

- Scope: the area of the business impacted; the nature and timing of the impact
- Baseline/scenario: the key baseline metrics pre-smart metering; the selected scenario for change
- Business model: the changes to the business model to support smart metering - major or incremental
- Cost/Benefit: the costs and benefits across DPCR5 and ED1; benefit evolution into ED2
- Alternative scenarios/business models: alternatives to the selected approach that have been considered
- Implementation plan: summary of next implementation steps

Key assumptions/baseline

The submission is based on the following baseline documents:

- The Ofgem 'Strategy Decision for ED1', 4th March 2013, as clarified by the RIGs tables, Glossary and Guidance issued 3/4/13, 26/04/13 and 16/05/13..
- the DECC programme plan, 20th December 2012 and associated one year delay, announced 10th May 2013
- Supplier rollout profiles provided by the DECC Commercial Working Group (CWG) , March 2013 (We have assumed one year slippage on these rollout profiles to align with the programme slippage)
- the Smart Metering Impact Assessment published alongside the Smart Metering Technical Equipment Specification (SMETS), 24th January 2013. The business benefits are wholly reliant upon the SMETS 2 variant of Smart Meters, or subsequent variants, being deployed for mass rollout and beyond. SMETS 1 supports very limited benefits for Distribution Network Operators.
- DCC Costings and Services as provided by the DECC CWG February/March/April 2013 and updated in January 2014 to reflect the latest DCC estimates of 12p per meter per year to 2015 and 20p per meter per year thereafter.

- The latest Government decision documents as of May 2013.

Any changes to this baseline, in particular the plan, smart meter functionality and DCC costs will require the submission to be reviewed.

3 Dependency - DNO interventions

3.1 Scope

Suppliers and their agents periodically identify a meter installation where there is a technical problem with the service equipment which requires a DNO to attend and undertake remedial work. These are typically identified during a meter replacement. The intensive rollout is likely to identify these earlier, leading to a significant expansion in these DNO interventions. This will bring the following key challenges:

- The need for approximately 72 additional Smart Meter Call out Craftsmen at peak with the appropriate level of knowledge & experience, good customer and safety skills:
  - These need to be established and retained in a period when there is a high competition for similar skilled resources and contractors. The plan must be responsive to potential high levels of attrition
  - There is a time lag for in-house (and possibly contractor) resources to meet 2015/16 demand, with recruitment and training time
  - The model must ensure a smooth and efficient transition of in-house resources into other similar positions at the end of the roll out to avoid significant redundancy costs
- Uncertainty: Notwithstanding the slippage announced on 10th may 2013, there remains uncertainty around the DECC programme timescales, with regards to equipment availability (SMETS 2)the procurements and the go-live date. There is further uncertainty around the Supplier rollout profiles, with Suppliers still developing their own strategies in light of the programme uncertainty. These strategies are also likely to focus only on achieving the key roll out objectives of the Suppliers and not ensure a consistent level of interventions, proportionate to customer numbers within the three licence areas of UK Power Networks and the smart meter rollout profile. Our analysis has also highlighted issues with the internal quality of data feeding into the analysis.
- London specifics: the London region offers particular challenges in terms of the significantly high proportion of properties with multi-phase supply, where external excavation involving street works may be required to ensure the safe completion of an intervention.

The business model will need to be able to address these issues and deliver interventions efficiently and effectively and with a high quality customer experience. It should be noted that the customer will already have had an aborted installation, will require an intervention visit and a subsequent installation visit. There is clearly a customer experience risk and potential brand risk to UK Power Networks in this situation that needs to be managed. We are proposing specific approaches to address this.

Baseline/scenario:

Ofgem has indicated a core allowance of 2% of smart meter call outs. This yields the following intervention profile (including aborts and non-valid referrals):

Table 4 Call out profile based upon a level of 2%

	2014	2015	2016	2017	2018	2019	2020	2021
EPN	505	2903	7529	14697	19044	20919	20411	14379
LPN	248	1441	3511	6150	7876	8749	8656	6265
SPN	307	1870	4893	8900	11516	12942	12870	9291
Total	1060	6214	15932	29747	38436	42610	41936	29935

It is important to note that the London figure is based on a 2% rate against the number of *services*, not the number of meters. This is to reflect the significant number of multi-phase buildings in London. London has c.2.2million meters, but only c.1.45million services. This reduces the overall volume of jobs in London, but significantly increases cost, as multi-phase supplies are more complex.

Industry experience from Low Carbon London is that interventions are 2.7% and Eon has publicly declared 2.5% from some of their early installs. It is prudent therefore to plan a flexible model that allows for a greater amount, recognising that Ofgem will need evidence to support the figure. Ofgem has indicated that increases from 2 – 10% will be allowable at agreed rates subject to evidence.

Historic evidence suggests that interventions are broadly split 20/80 between emergencies and planned, with the introduction of the MACOPA guidelines and the new categorisation, detailed split information will become clearer during 2013.

We have followed the latest Supplier rollout profile supplied by the SMIP Commercial Working Group.

We note there is likely to be severe competition for trained direct labour and equivalent skilled contractors during this period. We have held contractor rates at their current level on the assumption we will improve our contract negotiation and management processes; this is an aggressive assumption given the high demand for contractors during the period. We are also developing a recruitment, retention and contractor management strategy to hold these rates as low as possible.

3.2 Post submission review of costs

Following on from the RIIO submission feedback we have reviewed our Smart Metering Interventions delivery strategy against the outputs and have included all of the ancillary items into the 2% volume. Our submission previously included these as an additional works and had an adverse effect on the modelling. As part of the review we have also made some reductions to the associated direct and indirect costs which are explained in the following notes.

The notes below will cover the differential in composite UCI between the LPN, EPN & SPN direct cost submission to the industry median.

Table 5 Post submission review of costs

EPN	July 2013 Submission (Cost £m)	March 2014 Revision (Cost £m)	Cost Difference	July 2013 Submission (UCI)	March 2014 Revision (UCI)	% Difference
Indirect	8.5	3.3	-5.3	129.6	49.3	-62%
Direct	25.9	19.3	-6.6	392.8	292.8	-25%
Total	34.5	22.6	-11.9	522.4	342.1	-35%

LPN	July 2013 Submission (Cost)	March 2014 Revision (Cost)	Cost Difference	July 2013 Submission (UCI)	March 2014 Revision (UCI)	% Difference
Indirect	3.6	1.5	-2.2	129.9	52.1	-60%
Direct	23.2	18.1	-5.1	828.8	646.3	-22%
Total	26.9	19.6	-7.3	958.7	698.4	-27%

SPN	July 2013 Submission (Cost)	March 2014 Revision (Cost)	Cost Difference	July 2013 Submission (UCI)	March 2014 Revision (UCI)	% Difference
Indirect	5.8	2.1	-3.8	141.7	50.3	-65%
Direct	16.1	11.3	-4.8	392.2	275.8	-30%
Total	21.9	13.4	-8.5	533.9	326.0	-39%

UKPN Total	July 2013 Submission (Cost)	March 2014 Revision (Cost)	Cost Difference	% Difference
Indirect	18.0	6.8	-11.2	-62%
Direct	65.3	48.8	-16.5	-25%
Total	83.3	55.5	-27.7	-33%

3.2.1 Indirect Costs

UK Power Networks 1st July 2013 Business Plan was based on the assumption that the expected scale of Smart Meter call outs would require a dedicated team.

We have since revised this strategy, in order to achieve Ofgem's efficiency challenge, for the Smart Meter call out work to be integrated within 'Business as usual' delivery teams. The Overall Smart Metering Programme Management will now form part of the newly formed Capital Distribution Delivery team responsibilities allowing a rationalisation of resource, whilst maintaining a focus on successful Programme delivery. This review in delivery strategy has resulted in a cost reduction of £6.5million in Indirect Management costs.

3.2.1.1 Training Costs Review

We have removed the recruitment and training cost associated with the additional Smart Meter Jointers, as these were already covered in Business Plan Annexe 16: Workforce Renewal, resulting in an Indirect Cost reduction of £4.2million.
We also removed the allowance for Jointing Coaches in all three DNOs and incorporated into line management supervision.

3.2.1.2 Call Centre Cost Review

We have reviewed the resources required and feel that the process and IT changes being undertaken will reduce the level of Customer Service agents required to field Interventions requests, resulting in a cost reduction of £0.7m.

3.2.1.3 Transport Costs

The transport tools and PPE cost is omitted from CV109 tables.

3.2.2 Direct Costs Adjustment

To align the application of tables, onsite work elements e.g. aborts, inspections, misc. repairs are now included in the 2% call out threshold as opposed to being over and above the baseline as previously allowed for in our July 2013 Business Case. We have also reviewed the direct UCI costs and believe these represent efficient rates when taking into account the following specific regional challenges:-

3.2.2.1 Network Constraints – LPN specific

With the additional security of supply design through LV Interconnection in the London area there are operational considerations for each intervention that require an AP (Authorised Person) to check the network running arrangements and prepare for safe working. We have included an allowance of 3 additional Authorised Persons in LPN only. Of the cut out activity, 25% of call outs require a prior instruction agreed and monitored through network control to install safety fusing. 3 additional Fusing and Linking Teams are required in the LPN area to make the network safe prior to commencement of works.
These result in an additional £68 UCI impact in LPN only.

3.2.2.2 Multi Occupancy Dwellings

The 2011 Census information, supplied through the Smart Metering Central Delivery Body (CDB), provides the % of multi occupancy properties for England and Wales. From this data, 50% of London, 20% of South East and 16% of East of England is multi occupancy property, compared with 11% in the East Midlands. 12% in Wales, 16% in West Midlands and 14% in the North of England. It is also noted that significant volumes of EPN and SPN customers would be subject to the LPN impact as they reside within the geographical area of London linked to the CDB analysis.
From this data supplied, we have considered the mix of 3 phase vs. single phase work in each DNO, providing 3 phase Interventions for LPN at 19%, SPN at 13% and EPN at 10%.. At peak we will require an additional 5 Surveyors in EPN, an additional 2 surveyors in LPN and an additional 3 surveyors in SPN over the ED1 period, which is covered by the Service Inspection line process.

Given the significant difference between the number of customers and services in the LPN area, we have applied the 2% Intervention rate against the number of services as opposed to the number of customers. This reduced the 2% volume driver from 2.2million to 1.45million which will have an impact on the LPN UCI compared to other regions. The multi occupancy effect reduces the volume of services, which subsequently changes the balance of the three phase work and resulting net increase in UCI of £13 per cut out change unit in EPN, £105 per unit in LPN and £12 per unit in SPN over the industry median

3.2.2.3 Civils - Excavation and Reinstatement Costs

Excavation and reinstatement work related to a cut out change is required to find a point of connection in the footway and carriageway, In LPN, there is a higher rate of excavation work required due to the network being underground and limited opportunity to excavate in the verge or private land due to the nature of property boundaries. The opportunities for private excavation (unmade land) in the LPN area are 5% with 95% attracting higher costs for excavation, materials importing, reinstatement and disposal. In EPN 45% of the excavations are enabled in private (unmade ground) with SPN a similar profile. EPN and SPN also have significant London Borough area impacts, within the M25.
Excavation is required on a range of work types including all three phase cut-outs which cannot be worked on live and some single phase cut-outs which as part of the risk assessment are deemed to be of a type unable to operate on live or in an environment which prevents a safe working area. As a result of the excavation a significant impacting element is the profile of the mix of highway to unmade – i.e digging on private land or in a grass verge which versus Highway excavations in made footpaths costing significantly more as NRSWA specifications and implications apply.

There is also a requirement for Pipe Cutting resource due to the higher volume of continuous steel pipes on services in the London Area.
The additional UCI impact over and above the industry median is £15 per cut out change unit in EPN, £41 per unit in LPN and £10 per unit in SPN.

3.2.2.4 Lane Rental and Streetworks Permitting Charges and Parking Fees

London Borough and Transport for London roads have a significant cost effect through Lane Rental Charges which are unique to the UKPN licence areas, and through the additional cost of Streetworks Permits. Areas outside the southeast have less than 50% of UKPN's streetworks charges. The cost of parking meters and the suspension of parking meters or other facilities also have an increased London area effect on these works. The additional unit costs are £12 in EPN, £115 in LPN and £8 in SPN.

Table 6 DNO comparison of UCI for Cut out work against the industry median

	EPN	LPN	SPN
Median	210	210	210
Network Constraints	0	68	0
Multi occupancy impact	13	105	12
Civil cost - Excavation and Reinstatement	17	65	10
Streetworks and Lane Rental charges	12	115	8
Regional salary impact	6	95	18
Target UCI (Cut out work only)	**258**	**658**	**258**
2012/13 RIGs actual UCI	**410**	**1070**	**410**

3.3 Income

The Smart meter installation programme is expected to identify issues including inaccessible service positions and meter enclosures which are damaged or of inadequate size, for which the supplier is expected to agree to take financial responsibility for. To mitigate the impact of this we are engaging with suppliers to understand their strategies and working with them to improve the interface efficiencies working together.
Inadequate meter and service locations providing access and communications issues will drive service diversions which have been assessed alongside existing volumes.
The drivers for external meter cupboard replacement have been considered and there is still some uncertainty around the effects of smart metering equipment fitting in some preformed external cupboards which are added to instances of irreparable damage to the core housing.
Non valid referrals are a further area for income and have been based on 3% of flow information being identified as a lower Asset Condition category i.e referred as Category A but found to be a B or a C, or referred as a Cat B but found to be Cat C.
The whole chargeable income mix will be driven by supplier's strategies and accuracy of data provided and a forecast included in Table 7.

Table 7 Chargeable income forecast

Revenue	DPCR5 £m	ED1 £m
EPN	0.05	1.38
LPN	0.03	0.66
SPN	0.03	0.73
Total	**0.11**	**2.77**

3.4 Business model/change impact

The key features of our approach are to:

- Build good quality data: Analyse our housing stock data and records and work with Suppliers to build good quality data that will move work from emergency to planned, allow greater efficiency and enhance the customer experience
- Bring forward work where possible ahead of mass rollout to smooth the peak workload and hence minimise cost
- Embed the interventions teams in the current business to maximise knowledge transfer, mentoring and the opportunity to mix different forms of work to maximise efficiency
- Identify and implement existing best practice across our areas and identify innovative approaches
- Develop a flexible resourcing approach to manage workload cost and uncertainty.
- Commence recruitment and training early, establish a retention strategy and aim to train resources such that they can be available for expected expansion in low carbon work post mass rollout
- Use the existing call centre with a small increase in staff to manage the additional calls and scheduling
- Put in place a charging mechanism for Supplier requested out of hours working appointments for planned interventions and any associated aborted calls.

These points are elaborated below.

Build good quality data

We have commenced discussions with Suppliers to identify how information can be provided early to bring work forward and avoid emergencies. Options could include, for example, meter readers taking photographs of meter installations to identify potential risk installations or a pre mass roll out premises survey to not only identify potential interventions and also capture asset condition and location data. This is clearly in the Supplier's interest, since it will afford a better experience for their customer, however discussions are at an early stage and we do not yet know the extent of the availability of such a service and whether Suppliers would seek to charge. We are also assessing our own records and knowledge of housing stock to identify potential 'hotspots', where we are likely to see recurrence of the same problem due to common age and nature of installations. We believe such initiatives will enable us to address some interventions early, enabling a far more efficient and customer-friendly approach.

Bring forward work ahead of mass rollout

Initiatives such as those above will enable us to bring work forward, either ahead of mass rollout, or into the earlier lower volume phases of mass rollout. We are recruiting and planning on this basis. This will reduce peak rates, reducing overall resource requirements, management overheads, and the risk of subsequent redundancy and ensure a much smoother roll out for Suppliers and customers.

Embed the teams in the current business

The business will be primarily managed through the existing three regions. This will: maximise the opportunity for efficient linkage with other forms of work; facilitate the transfer of business knowledge, mentoring and leadership from existing staff; encourage commitment to the company and help train staff for post-rollout careers.

Identify and implement existing best practice

In developing our submission, we have undertaken a high level review of best practice and included that within our estimates. We have also developed innovative approaches, which we will implement and explore with other participants.

For example, our South Eastern Power Networks operation has insourced much of its civil works. This so far has led to more efficient scheduling, lower rates and improved customer service. We will be reviewing the performance of similar activities in our other two regions and particularly in relation to smart meter interventions where civil works are required. We are commencing initial discussions with Suppliers and Meter Installers on the potential of working together where interventions are identified. We are exploring the possibility of assigning craftsmen to work alongside meter installers area by area that meter operators could call upon at short notice. The meter installer and DNO jointer would then work together. This would afford the customer a single visit, rather than three visits and significantly reduce overhead times. Such discussions are at a very early stage and clearly meter installers need to consider such approaches alongside their own imperatives.

The key best practice initiative is the extension of live working to minimise the number of excavations. This reduces cost and improves the customer experience. It will clearly need to be subject to stringent safety checks, training and approvals.

Develop a flexible resourcing approach

Following detailed analysis and assessment of resource build-up, we are planning on a ratio of contractors and direct staff varied through the regions, to reflect the different nature of the regions. Direct staff will predominately be focused on emergency and short notice work, with some planned work as baseload. Contractors will be focused on planned work, where it is easier to manage their work and performance. At peak we anticipate the need for approximately 36 additional teams. The model can be flexed with either increases or decreases in interventions

Commence recruitment and training early

We are planning to commence recruitment and training early to avoid competition with installation companies. There is a substantial training programme and staff can be deployed with experienced staff on early interventions as set out above, as soon as they are trained. We will establish a retention strategy to mitigate the risk of churn as the market intensifies. This will include loyalty bonuses and exciting career paths. In particular, we envisage this workforce providing key roles as we move towards a transformed electricity network in the latter part of ED1 and through ED2.

Call Centre Impact

We are planning to manage the customer interaction from our call centre. This will enable us to explain the issue, schedule the appointment and manage any subsequent queries. We believe our greater knowledge of interventions, aligned to our capability to schedule our own teams, will deliver the best customer experience and most efficient outcome. At peak, we will have a specific interventions team, with calls routed to that team. This will best enable us to build upon the knowledge gained from early rollout experience and offer the customer the most informative service.

3.5 Cost/benefit assessment

Cost

The costs are set out in Table 8 and elaborated on in Table 9 and Table 10.

Table 8 Interventions cost summary

Area	DPCR5	ED1
Recruitment and Training	£0.1m	£0.3m
Interventions – direct and contractor work	£1.8m	£48.8m
Indirects	£0.8m	£6.0m
Call centre		£0.4m
IT	£1.0m	£0.9m
Total	£3.7m	£56.4m

Table 9 Interventions area scope

Area	Scope
Recruitment and Training	Recruitment and training of c. 72 new craftsmen is included in our Workforce Renewal annexe. The Smart Meter plan also allows for the recruitment and training of 10 new Surveyors and Jointers Mates. The bulk of this work needs to be undertaken in DPCR5, to ensure we have a trained workforce ready for the start of mass rollout in 2015. Post DPCR5, there will be some continued work to build towards the 2018 peak and to replace leavers.
Interventions – direct and contractor work	This is the direct labour and contractors to carry out the interventions. This cost is on a UCI basis and incorporates labour, contract, materials and operations. The bulk of the work is carried out in ED1, but we aim to bring work forward into DPCR5 where possible.
Indirects	This is the indirect labour and operations required to manage and support the work. For example, management and scheduling. Costs reflect the additional resources required to supplement existing management and scheduling staff.
Call centre	4 additional call centre agents covering the three licence areas to handle customer calls flows and emergency dispatch for category A work.
IT	Additional scheduling capability to cope with the additional intervention activity. This includes, for example, additional licences and hand-helds.

Our core direct costs are based on UCI figures as shown in Table 10.

Table 10 Proposed UCI figures (Cut out work only)

Intervention Type	UK Power Networks UCI (£)
CV109	
EPN	258
SPN	258
LPN	658

Benefit

The key benefit associated with interventions is that the subsequent rates post mass rollout should decline, since most issues will have been identified. This is included in our RIIO plan and not separately identified as a smart meter benefit.

3.6 Alternative scenarios/business models

We have considered an extensive range of approaches to identify the optimum solution. These have included consideration of a wholly direct model, extensive additional use of contractors, insource/outsource of different elements of work, in particular civils. Overall, we consider the selected approach delivers key benefits:

- Optimises the customer experience
- Lowest cost/risk balance
- Provides flexibility for changes and to a certain extent programme uncertainties

We have modelled different scenarios on intervention rates. We believe the business model is resilient and scalable up to a 5% intervention rate, although there is associated cost risk. Beyond 5%, there may be a need to establish a dedicated delivery unit. We believe this is unlikely based on existing evidence and our strategy to advance interventions wherever possible. However, there is some risk that Suppliers may defer interventions to maximise early rollout and there is hence some risk of increases towards 2019. We will seek advance information from Suppliers and monitor the rate of intervention closely such that we can adapt our strategy if evidence reveals there is a risk of a >5% intervention rate.

3.7 Implementation plan

We have established a programme team to deliver our strategy and be ready for mass rollout in 2015 and earlier interventions wherever possible. This includes:

- Establishing a programme team
- Delivering the recruitment and training strategy
- Discussions with Suppliers, meter installation companies and meter operators to identify the optimum inter-working approach
- Developing new processes and procedures to enhance delivery success and quality & safety assurance
- Developing and delivering our contract management strategy

4 Dependency – interface and income management

4.1 Scope

Core industry systems, interfaces and codes will require some change to support new smart metering data, processes and governance. There are three broad areas to consider, Registration, the Smart Energy Code (SEC) and DUOS charging and settlement.

Registration

Each DNO provides registration functions as part of the Meter Point Administration Service (MPAS) in accordance with the requirements of the Balancing and Settlement Code and the Master Registration Agreement (MRA). The registration systems send and receive flows to other industry and internal systems. DECC have specified additional data items to be held and business rule changes for registration systems, for example: interact with the DCC; hold additional data items related to Smart metering; hold the Unique Property Reference Number (UPRN) to be maintained by the distributor; change existing data flows and ECOES (an electricity industry website) to incorporate the new data items; change validation rules including Supplier Objection Processing.

Some of the required changes have been codified in the MRA but more MRA and BSC change will be required to meet DECC requirements for registration systems to work with the DCC, to aid rollout and improve the market operation.

We have assumed that changes to software will be required in 2013/14 and 2016/17. We have assumed that the volume of data processed will double by 2018/19 and then double again by 2019/20. DECC have indicated that the output data flow from the registration system will need to be delivered to the DCC by midnight. This will require most of the end of working day batch process to be completed in less than 6 hours, compared to the current 12 hour window.

We note that the DECC IA assumes that Registration will be centralised and managed by the DCC from 2-3 years after go live. This is currently under the governance of Ofgem's Smarter Markets programme and no date has been set and there is no formal specification or strategy. The Ofgem Glossary clarified that costs for this should not be included in the RIGs submission and that should be limited to changes identified by the Consequential Changes Working Group.

Smart Energy Code

This new code will govern all licensed parties and others who require services from the DCC. UK Power Networks will need to interact with the SEC Panel and DNO representatives.

Half Hourly Settlement

The introduction of smart metering provides the opportunity for the centralisation of data processing and data aggregation and half hourly settlement. The DECC programme has indicated a desire for such changes to happen within the next decade. Ofgem has requested Elexon to report on an approach and timing for such changes. Elexon has reported using 2020 as a baseline for potential change. Ofgem is yet to respond to the report. UK Power Networks believes these would be major changes that would require detailed consideration at the time. Our current assumption is that such changes will not happen in ED1.

4.2 Business model/change impact

We have assumed only incremental change to the business model.

Registration/SEC

There will be a rise in the number of 'registration' enquires due to; additional data, increased site visits and the new interface with the DCC. This will require additional staff resources to manage these. The assumption is that two additional staff will be required from 2014 to 2016 and one additional staff from 2016 to 2018.

The SEC will require contact management to communicate code changes across the business. The contract manager will also need to ensure that we are correctly represented on working groups and co-ordinate code changes raised by the business. The assumption is that one additional FTE staff will be required:

Half Hourly Settlement

Our current DUOS system manages 30,000 Half Hourly billed customers and is capable of extension to 150,000, which would cover any non-domestics requiring Half Hourly billing. We assume there will be no significant increase above that as noted above. We have assumed no change is necessary.

4.3 Cost/benefit assessment:

Costs

The costs are estimated in Table 11

Table 11 Industry interface and income cost summary

Cost (£)	DPCR5	ED1 capex	ED1 opex	Description
Additional staff	0.2m	-	0.6m	Additional staff to process registration queries and manage the SEC
Registration changes	1.2m	0.6m	1.6m	Registration changes

Benefits

This area is an enabler to the rest of the business and no specific benefits accrue.

4.4 Alternative scenarios/business models

We considered the potential move to half-hourly settlement, but we believe this is a major venture that would require focused cross-industry effort to specify and is unlikely to happen in ED1.

4.5 Implementation

We have commenced implementation of registration changes for 2013.
We will work with Ofgem and DECC to understand the timing and design of centralised registration, but note that is not currently included in our costs as per Ofgem guidance.

5 Dependency – privacy and security

5.1 Scope

The advent of smart metering will provide remote access to every premise in the country and access to detailed 24 hour consumer data. This access will be via the DCC; UK Power Networks has no rights to direct access to the meter.

Access has to be carefully managed and will be governed by rules set out in the Smart Energy Code (SEC). UK Power Networks will accede to the code to fulfil its responsibilities with regard to registration and to receive services from the DCC. UK Power Networks therefore needs to establish processes, procedures and IT to fulfil the security and privacy arrangements.

5.2 Baseline/scenario

The security model is currently undergoing revision following a review by the Communications-Electronics Security Group (CESG) last summer. The model when issued will provide the rules which participants need to fulfil to interact with the DCC and hence the premise equipment and data. It is not expected that DNOs will be able to access critical commands and hence it is assumed that the security requirements on DNOs will be less than for Suppliers.

The privacy rules have been set out in the Government response on Data Access and Privacy, December 2012. These state broadly that DNOs will be allowed access to data without the consent of the customer where they have had plans to approve potential privacy concerns approved either by DECC, up to 31/12/2014, or subsequently by Ofgem. This will be enforced by licence condition.

The plans will need to address the following points:

- explain what energy consumption data will be accessed, in what format, over what period of time, from which consumers, and for which specific purposes; where purposes must be relevant to the DNO's licence
- identify and quantify the benefits that could be delivered for different groups through access to this data
- demonstrate that practices, procedures and systems can be implemented to aggregate the data
- explain how collation, maintenance, usage and deletion of the data would take place securely
- show that consideration has been given to best available techniques for treatment of data
- be accompanied by a Privacy Impact Assessment

DNOs will be allowed access to individual information from premises, such as voltage reads, subject to adherence to the Data Protection Act.

Business model/change impact

We will provide clear ownership for privacy and security through our Information Systems Directorate. They will be responsible for developing the aggregation plan, PIA and monitoring adherence.

We currently assume that the DCC Head-end which we intend to procure will provide security functionality to meet the security model and aggregation functionality.

Cost/Benefit assessment:

Adherence to these requirements is fundamental to interaction with the DCC from which all smart benefits flow.
We have assumed that the new DCC Head-End will provide appropriate functionality (see DCC section below).
We have assumed staff and administrative costs are included in the SEC management costs already cited.

Alternative scenarios/business models

We currently assume that the DCC Head-end will meet the technical aspect of these requirements. If that is not the case, alternative methods will be sought.

Implementation plan

We continue to work closely with the ENA to monitor programme progress on resolving the security architecture. We will, subject to consultation with the DCC and its contractors, develop our aggregation plan in spring 2014.

6 Dependency – DCC costs

6.1 Scope

This section assesses the costs and benefits associated with the DCC. The DCC is projected to come into live operation in Q4 2015. UK Power Networks will be liable to a fixed cost per meter point per annum from July 2013 and for optional transaction service costs which we elect to use to drive business benefit.

UK Power Networks understand that charging for all alarms such as last gasp and all alerts will be included in the fixed fee. We have not included any additional cost for these services

6.2 Baseline/scenario

The fixed costs below are based on our 7.721million meter base, installed in line with the latest rollout profiles and a fixed charge of £0.20 per meter point per annum from April 2021. For the period July 2013 to March 2015, we have allowed for £0.12 per meter point per year in line with the DCC charging statements issued in November 2013 and January 2014.. We have assumed all fixed costs will be passed through up until the end of mass rollout (2020/21), including those incurred in DPCR5.

The variable costs are based on selected optional transactional services. UK Power Networks has reviewed these and assessed those that will drive greatest benefit to the business. These have been discussed with DECC and form the basis of our submission to the Commercial Working Group. These are primarily:

- The service to check energisation status of a meter. (7.4.01 – Read Supply status)
- Services to build asset management data:
  - hh time-series energy profiles; these would be captured as 3-month blocks of data and would be collected at our head-end and, using a connectivity model, aggregated to provide a hh network load profile. we have assumed that by 2024 10% of meters in any year would be used to collect this data - on the assumption that we would focus on known highly loaded networks;
  - Average. hh RMS voltage – again captured in 3-month blocks of time-series data. This is complementary to the hh energy data as it will permit voltage monitoring at any selected node (meter point) on an LV network. We have assumed that at 2024 10% of meters would be used to collect this data in any year on the assumption that we would focus on networks likely to have voltage regulation issues;
  - MD readings – configurable over a defined period, this enables DNOs to collect hh avg. active energy import and hence derive an MD (power) figure at any given meter. We have assumed this data would be collected from 10% of meters p.a. at 2024 (MD readings taken from a number of adjacent meters would provide an indication of network loading and reduce the need for hh time-series data – or could be used to identify networks where hh time series data should be taken from);
  - Real-time average hh RMS voltage – this has a latency of 30 sec and could be used to feed into an algorithm in the control system of a local voltage regulator or distribution transformer on-load tap-changer. This is a potential significant cost driver due to the frequency of messaging (i.e. one message every half hour) and so we have limited this to 0.1% of meters p.a. by 2024 (this nominally allows for meters at strategic nodes on an LV network to send voltage information and would be used only where local control of voltage proves necessary);
  - High / low voltage alerts triggered by configurable thresholds. We have assumed that at 2015, 2% p.a. meters in any year would be set up to transmit alerts (typically we'd select meters at the end of networks prone to voltage issues and/or closer to the substation for networks with PV clusters);

6.3 Business model/change impact

There is no change to the business model. Management and payment would be undertaken by our Income Management department. The data would be used by the Faults team and Asset management team to drive benefit.

6.4 Cost/benefit assessment

Costs

The DCC costs for the period are estimated Table 12

Table 12 DCC fixed and variable costs summary

£m	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Fixed cost – pass through	0.9	0.9	1.5	1.5	1.5	1.5	1.5	1.5		
Fixed cost – DNO funded									1.5	1.5
Transaction cost		0.015	0.048	0.108	0.184	0.267	0.348	0.363	0.363	0.363

We will also need to procure a 'head-end' system to support interfacing with the DCC. This is estimated at £4million

Benefits

The energisation check will deliver £11.1million benefit over ED1 and £1.9million pa at peak.
Last gasp will provide the basis for £3.7million operational cost saving in ED1 and £10.4million CML consumer benefit
The asset data and smart meter functionality will provide the basis in ED1 for:

- £19.5million ED1 benefits related to losses reduction (accruing to Suppliers)
- £1.5million savings on LV refurbishment
- £3.5million savings for customers on new connections from the reduced need for network reinforcement
- £4million savings through Active Network Management
- £13.5milion benefits through load shift/time-of-use tariffs

These will also be building the basis for far greater benefits in ED2. These are discussed in more detail in the individual sections.

6.5 Alternative scenarios/business models

We will continually review the provision of service data from the DCC to gain the optimum balance between cost and the opportunity for benefits.

6.6 Implementation

We are working closely with the ENA and the DECC programme to understand the evolution of the DCC, its costs and services.
We are examining the marketplace for the most cost-efficient approach to the DCC 'Head-end'.

7 Benefit driven change – fault management

Benefit Driven Change – Fault Management, Operations and Customer Service

7.1 Scope

The provision of smart meter data from the DCC provides the opportunity to improve performance and the customer experience in fault management situations. The primary opportunities arise from:

- Energisation check: the DCC will offer a service to remotely test a meter status
- 'Last Gasp': the DCC will automatically notify UK Power Networks where meters go offline, helping us to identify faults earlier and more accurately and to provide enhanced information to the customer.

DECC and the ENA have reviewed these opportunities and identified benefits in the areas of: reduced nugatory visits through energisation checks; reduced fault operational cost (opex); reduced CMLs; reduced calls. We have used this to drive our analysis and also sought additional benefits.

7.2 Baseline/scenario

We have reviewed potential benefits from the DECC/ENA analysis against our current business model and in addition sought to identify whether there is an opportunity for transformation arising from this data.
We have specifically identified numbers of nugatory visits for energisation checks, identifying a weighted annual average of 11,000 over the last 3 years.

7.3 Business model/change impact

Energisation Check

We will adapt our call centre processes to take advantage of this opportunity. When we receive a customer call notifying us of an outage, in a non-fault situation, the call centre agent will trigger an energisation check. This should take 30 seconds according to latest DECC estimates. The call centre will explain to the customer the process being undertaken and the benefits to them and ask the customer to hold. If the energisation check indicates that the problem is on the DNO side, an operative will be dispatched and the customer given an approximate time of arrival. If the problem is on the customer side, the agent will explain this to the customer and help the customer to understand how to address the problem.

Improved information: Fault Management and customer service

We will make improvements to our general fault management processes and in particular to those associated with low voltage faults. We will use the information from smart metering alongside our existing diagnostics to more accurately identify faults and target appropriate crews. We anticipate that the improved information will allow improved identification of faults, enabling faster attendance and an increased capacity to ensure the right team attends with the right equipment in the first instance. We further believe there will be benefits in storm situations from being able to undertake energisation checks, which will provide greater understanding of the progression of rectification and better targeting of crews on the ground.
We have considered whether smart metering provides an opportunity for transformation, but we believe that, given our current good quality diagnostics, it provides evolutionary rather than transformation opportunities. We will continually review our fault management processes as real-time information becomes available through the DCC, in particular the process of sending a DST to site before a crew attends – we believe it will be increasingly possible to obviate the need for this step. We will build smart meter data in as an integral part into our overall Transformation programme.
We see significant opportunities to improve the customer experience in fault situations. We will commence a move of our customer service operations from 'inbound reactive' to 'outbound proactive'. We will use the information available to maximise the speed and quality of information available to the customer, winning their trust and paving the way for reduced calls in the latter part of ED1 and ED2. We will tailor our Interactive Voice

Response (IVR) and identify and implement pro-active mechanisms of communicating with the customer, such as text message, to provide information on faults and rectification progress.

7.4 Cost/Benefit assessment:

Benefit

We have reviewed the DECC and ENA benefits and also sought to identify additional benefits. These are set out in Table 13 and described beneath.

Table 13 Fault management, organisational and customer service benefits summary

Benefit	Quantitative benefit				Qualitative benefit
	DECC IA	ENA	UK Power Networks	Customer	
Energisation status	£28m	-	£11.1m		Customer gains immediate understanding of fault
Improved fault information: -Reduced fault opex -Improved customer experience		-	£3.7m		Customer receives significantly improved information from call centre agent or IVR on location and extent of fault and likely time to rectify. Potential to contact the customer pro-actively and individually via text message or another communication route.
Reduction in CML	£18m	£6m		£10.4m	
HV Spurs	-	-		Not quant.	Negligible financial benefit but improved customer service for associated connected customers, particularly post storm events.
Reduced calls	£6m	-			
Total by party			£14.8m	£10.4m	
Total all parties	£52m[4]	£6m[5]	£25.2m		

Energisation status: We estimate that we will avoid c. 11,000 nugatory visits a year by the ability to test the meter status. In the ED1 period this will save £11.1million. The benefit is realised in proportion to the rollout and at full rollout will measure c. £2million pa.

The customer will also benefit, since we will be able to advise them on the nature of the fault straightaway and guide them on how to address the issue; they will not need to wait for a visit from the DNO to begin to address the problem.

Improved information - Reduced Fault Opex; We concur with DECC's view that fault management benefits will not be realisable until at least 33% of smart meters have been installed, to provide adequate clustering; on current rollout plans this occurs at 2018. From that point, we anticipate incremental change to our processes as set out above to realise benefit.

We do not concur with DECC's view that this can deliver 10% savings[6]. We already have good diagnostic intelligence that enables us to target faults quite accurately based on customer calls. This generally enables us to schedule crews correctly. We have reviewed the ENA's position that there is no benefit and instead have identified c. 1.5% pa saving in the fault opex budget. We will review and seek opportunities as data becomes available.

Improved information – customer service: we will implement changes to significantly improve the quality of the customer experience and deliver significant qualitative benefits as set out above.

Reduction in CMLs: We concur with DECC's and the ENA's view that the increased information will deliver improved CML performance. We do not agree with DECC's 10% reduction for the reasons stated above. We have estimated an average 10 minute reduction in each low voltage related fault, which customers will value at £0.37. This gives a £10.4million benefit in ED1 and a £1.94million pa benefit once rollout is complete.

We have identified an additional benefit for customers with direct connection from high voltage overhead line spurs. These in general do not have telemetry and it is not possible to identify the fault immediately. Smart metering will enable better targeting and faster restoration.

[4] Note the DECC IA figures assume a mass rollout end date of 2019 and hence overstate the benefits

[5] Note the ENA figures assume a mass rollout end date of 2019 and hence overstate the benefits

[6] The DECC IA is unclear on the composition of the 10% figure. The fault figure includes an allowance for single faults, which are probably energisation checks, but there is a separate section on energisation status which is noted as not quantified.

We note there will be some increase in CMLs where the outage is measured from the time stamp on the meter rather than the first customer calls. This could have a significant impact on overnight calls, where there may previously have been a delay of several hours prior to notification. We have assumed this will be offset by the benefits above.
Reduced calls: DECC estimate a reduction in calls during fault situations as the customer gains greater trust that the DNO is aware of problems and will fix them. We concur with this, but believe this will not be realisable until ED2. Further, we note we face a significant risk of increased general 'smart meter fault' calls, where the customer calls us by mistake rather than the Supplier; we have not requested any additional funding for these calls.

Cost

Benefits are dependent on the DCC Head-End cited above. Further IT investment and operational cost is required to achieve the benefits. This is summarised in Table 14

Table 14 Fault management and customer service cost

Cost	DPCR5	ED1 capex	ED1 opex	Description
Fault management and customer service changes	£1m	£1m	£2.25m	Enhancements to fault management systems to process the information received Enhancements to call centre systems for a new energisation process and new IVR messages and facilities to provide enhanced information

7.5 Alternative scenarios/business models

As noted, we have considered whether it is possible to transform the fault operation based on smart metering data, but do not believe this is possible. However, smart metering data will provide a key feed-in to our Transformation programme and aid the outperformance benefits that that will drive.

We note that increased benefit will be achievable in ED2 across all the areas noted above, when we plan to have completed a full LV phase model.

7.6 Implementation

Implementation of revised IT and processes to support energisation checks will be put in place in ED1.
Integration of smart data and improvements to customer service will be implemented in 2016.

8 Benefit driven change – network planning

Benefit Driven Change – Network Planning, Operation and the Path to Smart Grid

8.1 Scope

The provision of smart meter data from the DCC will provide far greater information than ever before on the network. This will:

- enable improvements in network planning, with an opportunity to avoid network reinforcement,
- enable improvements in operation, with active network management becoming a reality,
- and will pave the way for the path to the Smart Grid in ED2, with the role of the Distribution Network Operator, potentially becoming a 'Distribution System Operator' and managing a network with increased variable demand and substantive low carbon generation at both HV and LV networks.

DECC has developed benefit estimates through the IA; the ENA has actively contributed to the debate and to the IA in a series of papers mapping out the benefits from smart metering and the evolution through ED1 and ED2[7]. This has identified the following key benefits:

- Investment decisions
- New connections
- Avoided voltage investigations
- Reduced losses
- Active Network Management (ANM)
- Load shift/ToU

UK Power Networks has taken these as a basis and sought to meet, exceed or find additional benefits.

8.2 Baseline/scenario

UK Power Networks has already made allowance for the growth of low carbon technologies and smart metering in our core RIIO submission. The growth broadly follows the DECC Scenario 1 and our own scenarios as established by consultation with our stakeholders. This section hence contains pre-existing RIIO benefits and new benefits. It also provides commentary on the path to the smart grid.

8.3 Business model/change Impact

We will continue with the current business model through ED1. We will invest in the accumulation of smart data. We will invest in tools to aid interrogation and manipulation of that data; the tools will also link to planned upgrades to the GIS system.

This will form the basis for the realisation of benefits in ED1 and will build an extremely strong platform for substantial benefits in ED2 and the ability to manage the significant new planning & design challenges which smart networks and in particular LCT will present to Network operators.

[7] e.g. Analysis of Network Benefits from Smart Meter Message Flows Interim Review (phasing and categorisation of benefits)

8.4 Cost/benefit assessment:

Benefits

Table 15 sets out the potential benefits derived from the DECC IA and the ENA papers. It then presents the conclusions from our analysis, set out as:

- UK Power Networks RIIO Plan – benefits that accrue to UK Power Networks, but have already been included in our RIIO submission
- UK Power Networks New – new benefits that accrue to UK Power Networks
- Other – benefits that accrue to other parties, for example customers.
-

These are elaborated below.

Table 15 Network planning benefits

Benefit	Value in ED1					Comment
	DECC IA	ENA	UK Power Networks RIIO Plan	UK Power Networks New	Other beneficiaries (customers & suppliers)	
Investment Decisions	£20m	£5.5m		£1.5m		Current projected low levels of reinforcement mean that the comparable DECC/ENA benefit cannot be fully realised
New Connections		£4.5m			£3.5m	Benefit will accrue to new customers as connections are requested through reduced network reinforcement costs
Avoided voltage investigations	£7m	-				In the short term these will increase as smart metering will provide greater visibility. In the long term they will decrease
Reduced Losses	£26m	£28m			£19.5m	Reduced losses will accrue to Suppliers
Active Network Management (ANM)	-	£5m	£4m			Our RIIO plan already includes the use of ANM to reduce investment
Load shift/ToU	£2m	£18m	£13.5m			Our RIIO plan already includes the use of load shift to reduce investment. Note this is dependent on Suppliers.
Total by party			£17.5m	£1.5m	£23m	
Total all parties	£55m	£61m	£42.5m			

Investment Decisions and New Connections: DECC has estimated a 5% saving from avoided LV reinforcement and new connections. We concur with DECC's view that this is achievable, but believe that a significant degree of clustering will need to be established before there is sufficient information to inform the decisions. We have hence estimated 1% saving in 2020, rising to 4% in 2023. This benefit will accrue to UK Power Networks.

There is a further benefit in that many low voltage network reinforcement issues currently come to light through an outage when a fuse operation occurs. In future, these network loading issues should be able to be identified in advance and work planned, avoiding an outage with less impact on the customer and more efficient working practice.
There will also be opportunities to avoid reinforcement when undertaking new connections, based on improved information. These will be identified as new connections are introduced. The benefits will accrue to the customer.
Avoided voltage investigations: DECC estimate that there will be savings from avoided voltage investigations, given remote access to data. We concur with this view, but believe this is a long term benefit. In the short term, this is likely to reveal a significant increase in supply quality issues of which we were unaware, because the

customer had not reported them. We have therefore allowed for increased investigation cost in ED1. We believe the cost will reduce in ED2. The advent of more widespread LCT's is also likely to lead to an increased level of supply quality issues which will partly be overcome by more active network monitoring through smart meter data, increased low voltage network reinforcement works and also the likely introduction of some local network voltage control schemes downstream from primary substations where currently this functionality exists.

We note that our statutory duties require us to investigate situations where there is evidence of voltage outside of prescribed limits. This legislation was developed before smart metering and we believe there is a strong case for a review of the parameters to ensure we maintain a sensible engineering approach and to avoid the risk of an unnecessary substantial increased workload for DNOs.

Reduced Losses/Time-of-use tariffs/Active Network Management: These three areas are very closely related, with, for example, time-of-use tariffs and load management reducing stress on the network and hence avoiding losses, in addition to avoiding reinforcement. They are hence covered together.

Overall technical losses for GB networks are estimated to be around 7% of the energy produced. For distribution networks, the level of losses is equivalent to 17.5TWh per annum. These are likely to significantly worsen with the introduction of heat pumps and electric vehicles. The ENA has determined that the combination of demand side response (DSR) through time-of–use tariffs and/or active control of flexible demand has the potential to minimise the need for network reinforcement while maintaining losses at a roughly constant level. We concur with the ENA's views and have noted a benefit of £19.5million in ED1 – these benefits accrue to Suppliers. We include a technical paper at Appendix A: 'Impact of Demand Side Response – Enabled by Smart Metering – on distribution Network Losses under Demand Growth Scenarios to 2030', which sets out supporting technical evidence and analysis to support this stance.

DNOs will be able to access near-real-time half hourly average data and RMS data. This data can be used as an input to a local or regional control system to effect controls, ANM schemes applicable to LV networks include:

- Local voltage control schemes to optimise voltage levels with regard to maximising load factor (and hence capacity headroom) and minimising losses;
- Automated LV switching to optimise power sharing between electrically adjacent circuits;
- Soft normal open points (SNOPs) which deploy power electronics to allow network meshing for optimum load sharing with voltage optimisation.

The ENA estimate a c. £4m saving in ED1 (pro-rated to reflect the amended end date) and we concur with their view. A detailed technical rationale is included in the paper cited above.

The Path to the Smart Grid: We have identified a significant amount of benefit in ED1; however the real benefit lies in ED2. The data, systems, and knowledge established in ED1 will provide the platform for a transformed DNO role in ED2, moving towards a DSO that can support extensive low carbon technologies and distributed generation. This is a vital step in helping the UK secure long term sustainable energy provision. Our vision for the smart grid and how smart metering can support it is set out in a technical paper at Appendix B: Smart Grid Benefits from Smart Meter Functionality and Message Flows.

Costs

The costs in Table 16 have been identified. These are IT costs and the bulk of the cost associated with DCC transactions, which will be towards building a database to support network planning, operations and the smart grid.

Table 16 Network planning IT cost summary

Cost	DPCR5	ED1 capex	ED1 opex	Description
Data Warehouse	-	£2.5m	£1.9m	Data warehouse to store half-hourly data for subsequent analysis
Network Planning Tools and Data Processing		£4.5m	£2.25m	Tools to allow analysis of the data and modelling of scenarios and options for reinforcement and network management.
Transaction cost		-	£1.9m	Building asset data set

8.5 Alternative scenarios/business models

We have undertaken substantial analysis and uncertainty modelling of a broad range of scenarios for our entire RIIO submission. There is clearly a wide range of scenarios dependent on economic growth, Government policy, investors' appetite for risk and technological innovation and progression at an acceptable economic cost. The smart metering analysis above is based on the DECC scenario 1 and our own scenario.

There is unlikely to be a fundamental change to the business model in ED1. The key aims for ED1 will be to establish good data, systems and understanding to reap the benefits at the end of ED1 and in the move into ED2.

9 IT and communications change

9.1 Scope

We have identified significant IT requirements to not only support the core smart metering roll out but also to build the necessary platform for late ED1 and ED2 to facilitate and actively manage Smarter Networks through to the transition of becoming a Distribution System Operator. This section outlines our proposed solution to the requirements noted in each area above. .

9.2 IT model/change Impact

At a high level the solution comprises:

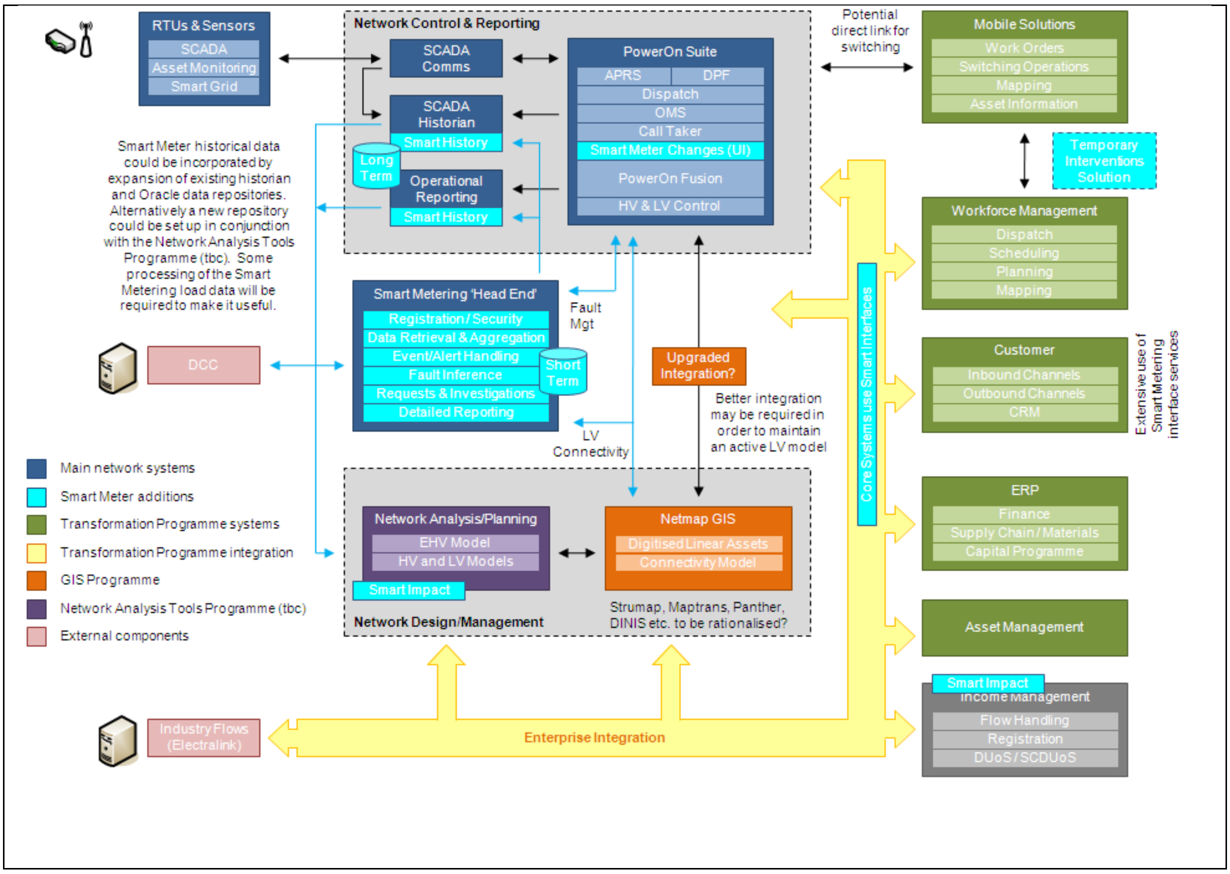
- One principle new system for all common smart metering functionality, interfaces and DCC integration – the 'DNO Smart Metering Head End';
- Specific modules and interfaces to support fault management and customer services;
- Data warehousing for the processing, analysis and longer term storage of smart metering data;
- Network analysis and planning tools to exploit this data and drive through to engineering conclusions;
- Mandated changes to registration and associated systems; and
- Enhancements and increased capacity to scheduling/work management to support DNO interventions.

UK Power Networks will aim to obtain its core smart metering functionality as far as possible through a single, commercially available software package acting as the DNO Head End, with minimal impacts to PowerOn and Netmap. Custom development will be considered in high value areas where there is a prospect of achieving differentiated performance for UK Power Networks versus other DNOs (for example fine tuning the fault algorithms in respect of the UK Power Networks specific connectivity data). Custom developments will not be used for undifferentiated or industry standard functions.

The Head End will interact with the DCC and through this with the smart meters. It will encapsulate the handling of DCC 'sensitive data' (such as individual energy consumption registers), with all outputs being aggregated as necessary so that the data is no longer sensitive when presented to users and sent out via application interfaces. Note that UK Power Networks has no option but to temporarily store and process sensitive data in this system as the DCC design requires data to be retrieved from each meter individually. There is no aggregation of data in the DCC itself.

Figure 2 illustrates the UK Power Networks solution in principle with the smart metering components and impacted areas highlighted in light blue. Each item is described below. The major systems 'owned' by other UK Power Networks programmes are highlighted in other colours.

Figure 2 Assumed Systems Schematic, Post-Delivery of Major UK Power Networks Programmes



Main Head End Functions

- **Registration, Security and other Common DCC Functions**. This is the functionality to manage the relationship between UK Power Networks and each smart meter throughout its life on the DCC. New installations will be announced via both DCC and industry flows, which need to be correlated and each accepted meter placed onto the UK Power Networks LV connectivity model. An exchange of security keys with the meter is required to prime it for meter reading by UK Power Networks and certain other functions. Standard configuration settings for alerts etc. need to be applied. Meters should be allocated into interest groups according to policies set by UK Power Networks (since it is only expected to read 10% of meters for each given purpose). This functional area will also deal with encryption/decryption, exceptions, deregistration of departing and exchanged meters and possibly the periodic update of security keys. Based on the current DCC specifications there may need to be common processing to translate DCC message responses from HAN-Ready format to a suitable text format (the DSP message translation service appears to be for outbound messages only).

- **Meter Data Retrieval & Aggregation**. This is the functionality to retrieve scheduled meter readings (4Q energy, MD, RMS voltage) from areas of the network that are specified as being of interest through meter group policies. There may be temporary polices for sections of network that are under investigation (e.g. following a cluster of power quality alerts). It is envisaged that most scheduled reads will be obtained by retrieving the full contents of the meter's 90 day buffer. However a small proportion (0.1%) of meters may be read on an instantaneous basis every 30 minutes in cases where UK Power Networks has an in-day intervention. Sensitive data will be buffered temporarily and securely in the Head End during an appropriate reading window (to allow for DCC latency) following which the data will be aggregated to form non-sensitive output records. The Head End will store a short history locally and write its output to a long term data store.

- **Event and Alert Handling.** This is the functionality to receive unsolicited events from the DCC and to harness them in ways that are useful to UK Power Networks business processes. Events can relate to energy import/export thresholds, RMS, sag/swell and other technical alarms. Outage events are a special case with particular functionality (see below). Other events need to be processed and correlated according to defined policies to determine whether a workflow action is required by UK Power Networks. Such policies may depend on the criticality of the network involved, whether sensitive customers are affected etc. The Head End will store all events (both original and derived) on a short term basis and then write its output to a long term data store.

- **Fault Inference.** This is the functionality to improve the fault management process using smart meter information. A full description is provided in a later section but the general scheme is for the Head End to maintain fault status at the level of LV connectivity features (typically LV ways or phases thereof) and to interact with the existing fault inference engine within PowerOn. It is assumed that this will be based primarily on last gasp and first breath events with selective polling of meters where necessary to resolve ambiguity.

- **Requests & Investigations.** This is the functionality for UK Power Networks users to interrogate individual smart meters or collections of smart meters (e.g. along an LV circuit) in order to draw conclusions about the local network conditions and to make more informed dispatch choices. The information presented will be a composite of data already held in the Head End and data retrieved in close to real time (30 second response) from the DCC. Typical uses are to avoid inspection visits where the cause of the incident is apparent, to check whether single property faults are customer side vs. network side, to validate power quality complaints, to reduce false alarms etc. There are also some ad hoc requests such as checking meter configuration and resetting voltage alarm counters. These capabilities may be made available as integration services, user interfaces or user interface components (e.g. Map displays) for incorporation into another application front-end such as Customer Records Management (CRM) (e.g. a mapping control). There are a number of options for producing map-based displays including active layers in Geoview. Alternatively Netmap could provide this support.
- **Detailed Outage Reporting.** This is the functionality to produce detailed historic records of LV outages post restoration. The impact of HV faults is already accurately calculated by PowerOn; every customer on the network downstream of the fault is counted as off supply. However smart meter data can be used to establish the impact to individual customers for faults occurring below the level of HV instrumentation. Meter event logs can be retrieved to confirm the length of interruption where there is not a correlated pair of last gasp / first breath events. In this way an accurate record of customer interruptions and minutes lost can be fed to the CRM system that may drive downstream processing such as compensation payments. Another detailed reporting function could be to derive phase membership for smart meters subject to phase-specific outages (where the UK Power Networks resolution is phase-specific or there is data from a 3 phase smart meter) or to identify potential anomalies in the LV connectivity model (i.e. meters unexpectedly present in or missing from an outage).

Other Smart Metering Impacts

- **Data Warehouse.** The Head End will act as a temporary cache for smart meter data. However other platforms will be required to provide a data warehouse for the longer term storage of smart meter historical data to be used in downstream processes such as network planning. At this stage the overall size of the warehouse has been estimated and provision made for storage and backup plus warehouse/analytics tools (e.g. Business Objects, SAP Hana etc. or additional PI licensing).
- **Network Analysis Tools.** The specific benefits identified for network planning will require specific network analysis and modelling tools to achieve them. For example UK Power Networks may require the capability to build bottom up load forecasts to understand current network capacity and to plan for future changes. In this case a composite view could be constructed from aggregated smart meter energy consumption, half-hourly meter data and unmetered supply data. The remaining (non-smart) supply points could be estimated from their profile classes and the overall model could be reconciled against grid supply data. Specialised tools exist to perform these kinds of tasks.
- **Registration.** This impact relates to mandated industry changes for 2013/14 connected with smart metering. These mainly relate to incorporation of UPRNs and SMETS indicators to existing industry registration data flows.
- **DNO Intervention Support.** This impact relates to handling the exceptional volume of DNO metering interventions anticipated during the national rollout. It may be necessary to provide interim solutions for smart metering as other systems are found to be unavailable or unsuitable. Existing systems will require licensing uplift to cope with peak volumes. Operatives will require hand-held devices.

We have elaborated below on the two key areas of outage management and data warehouse.

Outage Management

Outage management is a key area of capability for smart metering. Three key features have been identified in the DCC/SMETS2 design to support the business outcomes in the UK Power Networks benefits case:

Table 17 Outage management key features and outcomes

DCC/SMETS2 Smart Meter Features	Business Capabilities/Outcomes
• Last gasp event from Communications Hub (3 min delay) • First breath event from smart meter • Ability to request meter status and retrieve meter event log within 30 seconds	• Automatically detect the start and end of all outages below the level of current SCADA instrumentation (faults could be between primary and secondary substations, at the secondary substation or on the local LV network); • Automatically detect when underlying faults persist following restoration, so that action can be taken before crews leave the area; • Allow Customer Services to determine (in close to real time) whether a single property fault is on the network side or the customer side, to reduce the number of false alarms; • Allow users to visualise smart meter derived information on LV diagrams to help localise faults and to inform better despatch actions; • Create an accurate record of customer impact for LV faults affecting part of an LV mains supply – i.e. determine the CML down to property level and enable Customer Services to make proactive contact; • Detect anomalies that may indicate mistakes in the LV connectivity records (i.e. meters apparently on a different mains supply to that expected); • Gather data from suitable outages that may be used to infer over time which phase each meter belongs to.

We have investigated this area in detail due to uncertainties in the DECC specifications and the CSP/DSP tenders as to the precise mechanisms underpinning outage management. The CSPs in particular have proposed a variety of solutions in response to somewhat lightly defined tender requirements from DECC. It is important for UK Power Networks that the key features of the smart meter system are delivered in a way which is practical and allows the benefits to be realised.

UK Power Networks view on practical outage management principles (as represented to the ENA) is as follows

- **Events as Primary Basis.** Outage management should be supported as far as possible on DCC events – i.e. last gasps that can be matched up with first breaths. It would be inefficient on the SMWAN and less timely (as well as more expensive) to poll meters on a wholesale basis. Ideally polling individual meters and retrieving their event logs should be done by exception and normally post-restoration – e.g. to resolve meters having ambiguous status or unclear CMLs.
- **Event Filtering and Dither.** The solution needs to strike a balance between filtering mass messages from HV outages versus the risk of suppressing useful information about LV faults that are happening at the same time. The application of filtering thresholds at the level of CSP network 'cells' is likely to be workable since these are large enough to cover 1-5 primary substations on average. Telephonica, with its much smaller network cells, is not proposing to filter on this basis. The main concern for the DNO in any filtering scenario is that the unsuccessful messages should be randomly distributed rather than being localised in any way, so as not to mask or alter outage patterns. This could be achieved by building in a short random dither to the transmission time of the last gasp from the communications hub, so that all locations have a chance to report in before any thresholds are reached. Interestingly none of the CSPs had a firm view on filtering first breath messages that originate from the meter rather than the communications hub.
- **Prioritisation of Meters.** As a variation to the above it may be beneficial for DNOs to be able to nominate strategically placed meters (e.g. via event behaviour configuration) to emit their last gasps a few seconds ahead of time or to be immune from filtering. This is based on the observation that some meters are far more discriminating in terms of pinpointing fault locations than others. In the DCC catalogue it seems that three phase meters have different event codes for individual phase loss. Presumably such events should be immune from filtering?
- **Avoidance of False Alarms.** It is better for any CSP solution to be balanced so it is more likely for a few genuine last gasps to be missed off than for mistaken last gasps to be included. Even a small number of false alarms on circuits with no faults could be wasteful to the DNO's process and in the new world could lead to erroneous outbound customer contact. See section below on CSP solutions.

We intend to represent these principles to DECC and the CSP bidders in the next phase of work.

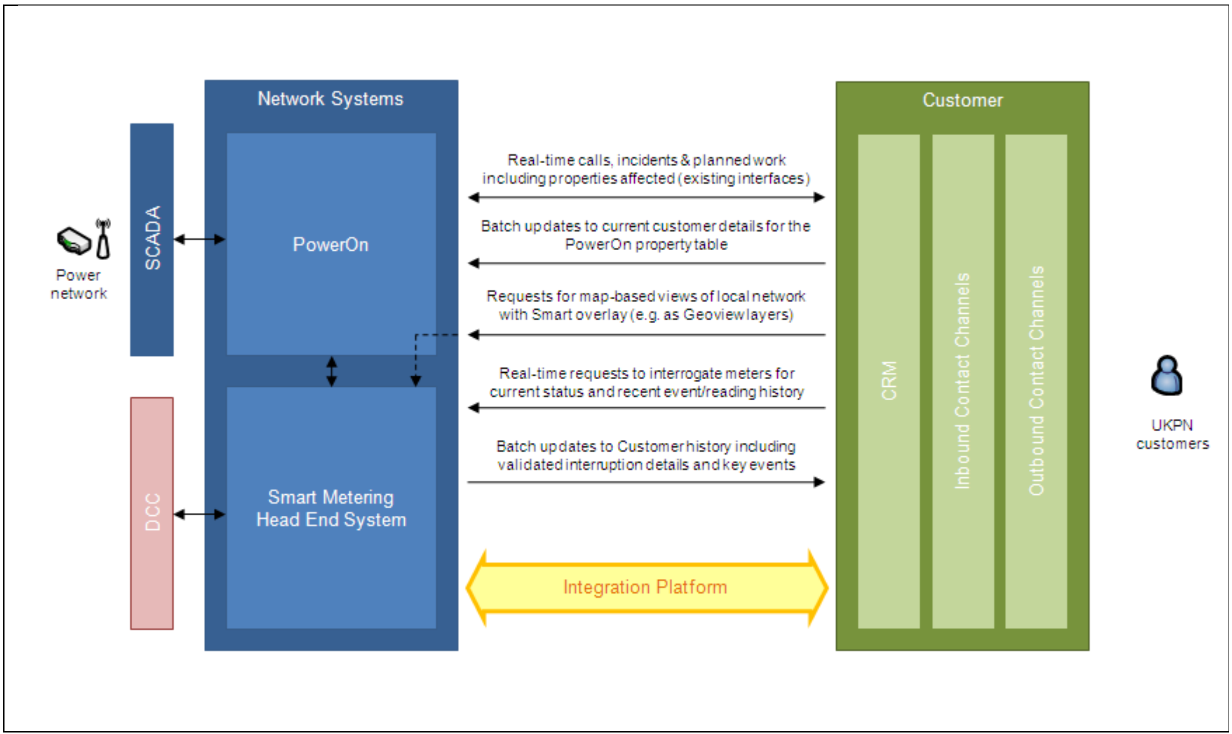
On the assumption that the final outage management solution is practical we have worked with GE Digital Energy to determine how the fault inference functionality is likely to be split between PowerOn and the Head End. PowerOn is fundamentally a network management system and its core processing will not operate at the meter level. The likely break down of responsibility between the two components is as follows:

- The Head End will operate at the level of calls and incidents that relate to an LV mains supply (e.g. a way on an LV isolator or a phase within a way);
- PowerOn will maintain the overall view of calls and incidents at all voltage levels, drawing its data from SCADA systems, customer contacts, network engineers and the Head End;

- The Head End (working in conjunction with other applications) will enable contact centre agents and other users to query individual smart meters or collections of smart meters on an affected mains circuit, in close to real time.

This is illustrated by the diagram below.

Figure 3 Indicative integration between network and customer systems



Note that some parts of the downstream HV network and secondary substations are beyond the visibility of current SCADA instrumentation. Faults in these areas may not be detected by SCADA but they will give rise to clusters of incidents in the SMS, each relating to an affected LV mains supply.

The general scheme for automated fault management is assumed to be:

- The Head End will use DCC alerts to continually infer the status of each LV mains supply (for example whether the circuit has a single property fault, an LV fault affecting multiple properties, voltage tolerance issues or is entirely off supply);
- The Head End will continually compare its LV status view against PowerOn's real-time view of incidents and planned work;
- Based on this comparison the Head End will raise calls (for single properties) and raise/update incidents (for second and subsequent properties) with PowerOn against the associated LV mains supply, filtering out cases where PowerOn is already aware of HV faults through its SCADA connectivity;
- PowerOn will automatically combine calls and smaller incidents into larger incidents using its existing fault inference functionality;
- The Head End will use 'first breath' alerts to confirm when supply is restored and may also retrieve event logs from individual meters to resolve ambiguity (for example some 'first-breath' messages may be missing from the set);
- The Head End will reconcile its view of LV status with PowerOn, raising or re-opening LV incidents as necessary in cases of partial restoration or underlying faults;
- The Head End will produce a post-restoration record for every meter affected by every LV fault for passing to the CRM system.

Data storage volumes

The historic data store will be sized according to the anticipated use of smart metering data when the programme is fully rolled out. It is assumed that granular data will be retained for 5 years and more summarised data will be kept indefinitely (or for at least two regulatory cycles). The current business assumptions for data collection are:

- 4Q energy demand 30 minute time series for 10% of meters (aggregated by profile class on each LV main);
- Maximum demand data points collected daily for 10% of meters;

- RMS voltage 30 minute (typical) time series for 10% of meters;
- Storage of all events/alarms received assuming 100 events per meter per year.

Some of the RMS voltage data may be obtained in near real-time for voltage control purposes as opposed to scheduled data retrieval. However this will not influence the total volume of data retained. It is assumed that where data is aggregated this will reduce the underlying volume of data stored by 90%.

Allowing for database overheads these smart meter volumes equate to roughly 10-20 TB at steady state. Given the uncertainties inherent in the design, the requirement to combine smart metering data with other data, and the multiplying effects of data analysis tools it would be prudent to assign a storage platform expandable to 100TB for this.

UK Power Networks network systems have availability service levels based on Business Continuity Classes 1 and 2. This implies that business data should be replicated across both corporate data centres.

Key Assumptions

- Our estimates are made on the basis of the following key assumptions on the national smart metering design
- Alerts, RMS voltage registers and maximum demand registers do not qualify as 'sensitive data' under the SEC and permission from customers is not required for the DNO to use this data to support its regulated activities.
- Four quadrant energy consumption registers are treated as 'sensitive data' under the SEC. However this data can be securely acquired by UK Power Networks without the customer's permission and aggregated across LV network features containing multiple properties, after which the data will no longer be sensitive.
- It will not be necessary for UK Power Networks to explicity register with every smart meter and to exchange security keys to recieve events. Exchange of security keys is a prerequisite to retrieving sensitive data
- DCC power outage management will feature proactive 'last gasp' and 'first breath' alerts as noted in the DCC catalogue, SMETS2 and Comms Hub specifications (but not described clearly in the CSP/DSP tenders).

9.3 Cost/benefit

9.3.1 Cost

The table below sets out a summary of the costs arising from the above, based on discussions with our IT providers.

Table 18 IT capex and opex cost summary

£m	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
Capex											
Head-end	1.0	2.0	1.0								
Fault management/ Customer services		1.0	1.0								
Data warehouse			1.0			1.5					
Network planning tools & data processing					1.0			2.0	1.5		
Income management	1.0					0.5					
DNO interventions		1.0									
Total Capex	2.0	4.0	3.0	0	1.0	2.0	0	2.0	1.5	0	15.5

Opex at 15%-One year lag	0	0.3	0.9	1.35	1.35	1.5	1.8	1.8	1.95	2.18	13.1
Total IT spend	2.0	4.3	3.9	1.35	2.35	3.5	1.8	3.8	3.45	2.18	28.6

9.3.2 Benefit

These are summarised at the beginning and specified throughout this submission and not repeated here. Virtually all benefits are dependent upon IT support.

10 Uncertainty and mitigation

This section outlines the key areas of uncertainty and the impact of that uncertainty.

Area of Uncertainty	Description	Impact
Approved funding		
Cost pass through	The costs that are permitted for pass through have not yet been clearly identified. For example, UK POWER NETWORKS wish to invest in systems to support Active Network Management, Losses management and Load shifting. However, the majority of benefits accrue to suppliers; these are very difficult to justify from a DNO perspective.	UK Power Networks do not invest unless funding is approved
DPCR5 Funding - Interventions	UK Power Networks' strategy is to train ahead of ED1 and undertake as much work as possible to smooth the prolife and cost. Funding approval and mechanism for this is unclear	UK Power Networks change strategy and increase workload in ED1.
DPCR5 Funding – DCC Costs	Funding approval and mechanism for DCC Costs incurred from July 2013 is unclear.	UK Power Networks has to allow cost
Interventions		
Number of Interventions 2-5%	Ofgem has set an allowance at 2%. Low Carbon London and industry evidence suggests that the intervention rate could be 2.7% or higher. Presently tier 1 resourcing of CAT A,B,C, from all sources is included in the 2% intervention resource profile.	Additional resource based on volume driver Additional overheads based on volume driver (recruitment, training, management, etc)
Number of Interventions >5%	Our business model is predicated on merging the Interventions work with core business to maximise efficiency. If Interventions exceed 5%, this may not be feasible.	Additional resource as above Revised business model with more costly overhead structure

Area of Uncertainty	Description	Impact
Staff cost rates	There will be a significant demand for DNO skilled staff. Our staff may be targeted by installation companies or other DNOs. Higher than normal pay increases and retention payments may be necessary. Also direct and contractor staff churn / movement may add cost.	Increased direct cost Increased indirect cost – additional training and recruitment
Increased contractor rates	There will be a significant demand for contractors. We have assumed we can improve rates and develop scalable efficiencies – this is a very aggressive assumption.	Increased direct cost Increased indirect cost – additional training and recruitment
Number of multi-phase jobs	Multi-phase jobs are significantly more time-consuming and hence costly. Historic data is limited. An increase in the ration of multi-phase jobs will drive up cost – the mix and opportunity for increases here are different by area in particularly LPN where 40% of customers are fed through multiphase services.	Increased direct cost Increased indirect cost – additional training and recruitment
Excavation/Lane rentals	Excavation can treble the cost of a job. This is a particular problem in London, where crowded strata can force the need to impact other companies' services. We have assumed a significant decrease in excavation based on live working – this is only partially proven.	Increased direct cost Increased indirect cost – additional training and recruitment
Rollout profile	UK Power Networks is dependent on the suppliers' rollout profiles. These are for information, not mandatory. Significant changes could cause nugatory cost	Inefficient rollout, increasing direct and indirect cost
Geographical focus	We have assumed some degree of geographical focus by suppliers to drive efficiency.	Increased direct and indirect cost
Access rates	Interventions will occur where a consumer has already had an aborted installation and will require a subsequent revisit for installation. Customer resistance and poor access rates are hence a high risk	Increased direct cost Increased indirect cost
Dumb meter disposal	UK Power Networks is currently the owner of 6,618,072 dumb meters which will require disposal once the meters become redundant. Investigations are progressing into the responsibility for this action and if UK Power Networks, what will be the most cost efficient process	Increased costs of roll out upon UK Power Networks
Industry Interface and Income Mgt		
Centralisation of registration	The DECC IA assumes this will happen in 2016-17. No allowance has been made (as per glossary)	UK Power Networks require additional funding
SEC Responsibilities	The extent of DNO responsibilities is unclear as DECC has not	Increased funding required

Area of Uncertainty	Description	Impact
	completed the SEC policy.	
Half Hourly charging/ settlement	Smart meters enable half-hourly charging and settlement. We have provided limited allowance for this. Any significant change will require additional funding	Increased funding required
Extent of non DCC Compliant Smart Meters installed	If Suppliers install a large number of smart meters during the Foundation phase which are not DCC compatible, it is likely that limited benefit will be gained particularly in relation to fault management and Network Planning.	Reduction in benefits
Privacy and Security		
Security architecture	DECC has not yet agreed the overall security approach, requirements, architecture and accreditation process. There is therefore significant uncertainty in our submission in this area.	Increased funding required
Privacy – access to individual data	We have assumed that access to individual data for energisation checks and voltage checks will be acceptable.	Reduction in benefits
DCC Costs		
Fixed rate	This is advisory only and is dependent on the CSP/DSP procurement. Any increase will render it impossible to cover costs with benefits	Increased funding to 2021 Strategy review post 2021
Fault Management		
Fault management benefits	Smart metering provides good opportunities. However, we already have good network information from our current systems. There is therefore a risk that not all the benefits may be realised.	Reduced benefits
Smart meter functionality and service provision by DCC	The latest Core Communication Schedule for inclusion in the Smart Energy Code does not adequately specify the functionality/ service requirements for a number of the key alarms and alerts essential to DNO's. The DCC could interpret the requirements to be of a lesser scope or service.	Reduction in benefits and/ or potential higher costs
Network Planning		
Network benefits	Smart data offers exciting opportunities, but also a step into the unknown. The nature and extent of benefits will be determined by accumulation and usage of the data over a long period and there will be variance in the benefits. It is also unclear at present as to whether data privacy requirements on consumption data will prevent adequate network performance/ loading visibility.	Increased cost Reduced/increased benefits

Area of Uncertainty	Description	Impact
Funding for asset cost reduction	As smart asset data is accumulated, UK Power Networks will be able to reduce LV investment based on better information. This will help fund the DCC costs. However, this is dependent on Ofgem allowing the full funding and UK Power Networks being able to realise the benefits. If Ofgem only allow the reduced level of asset funding, we will not cover DCC costs.	Increased cost
Voltage investigation	DNOs have a statutory duty to investigate and rectify voltage complaints when they become known. This is currently through customer communication. With smart metering, these will be known automatically. Since many customers probably tolerate voltage symptoms such as flickering lights, there could be a substantial increase in this activity.	Increased cost Increased customer inconvenience Ofgem should consider changes to Statutory legislation.
IT Costs		
IT capex	We have discussed IT solutions with vendors, through our own IT department and with consultants. However, the requirements for IT to support smart metering are currently at a very high level. This is particularly true of the areas that will yield most benefit, such as real-time network management. There is therefore uncertainty in these numbers.	Increased cost
IT opex	This is dependent on capex above. There is therefore inherent uncertainty in the figure.	Increased cost

11 Appendices

A.1 Impact of demand side response - enabled by smart metering - on losses under demand growth scenarios to 2030

A.2 Introduction and context

This paper provides a high-level parametric evaluation[8] of the potential impact on technical losses of demand side response and active network management facilitated by smart meter data. The focus of the paper is on LV network losses where the greatest impact of future electric vehicle (EV) and heat pump demand will materialise. The paper does not consider potential benefits of reducing non-technical losses which smart meters might give rise to. For example the ability for consumption to be recorded accurately by the smart metering system should all but eliminate errors due to estimated and missed reads - which currently appear as losses. Improved tamper alerts might also reduce theft although, conversely, in the absence of visits by meter readers, evidence of attempts to steal electricity through by-passing or other forms of corrupting the meter register might go undetected.

While reducing non-technical losses is important, of greater interest from an overall energy efficiency and carbon impact perspective is that of technical losses. Electrical losses are estimated to be currently responsible for 1.5% of GB GHG emissions (although this impact will obviously reduce as electricity generation is gradually decarbonised). DNOs have a regulatory incentive during DPCR5 (albeit not to be carried forward into RIIO ED1) to reduce losses (both technical and non-technical) - the DPCR5 incentive rate being £60 per MWh.

For distribution networks, technical losses fall essentially into two camps: fixed (or iron) losses and variable (or copper) losses.

Fixed losses (mainly associated with transformers in the form of hysteresis and eddy current losses) will, by definition, not vary with energy distributed or peak demand growth; such losses are more or less constant and are incurred continuously whilst the transformer is energised[9]. Variable losses are due to electrical resistance in conductors and are proportional to the square of the electrical current (or energy) passing through a conductor (for example a cable, overhead line or transformer winding).

A.3 Current levels of losses and apportionment across distribution network voltage levels

For a distribution network, typically around 30% of technical losses will be due to fixed losses and 70% due to variable losses (though there will be regional variations in this ratio). By voltage level, some 55% of fixed losses will typically be due to HV/LV distribution transformers and 20% due to EHV/HV transformers. For variable losses, some 45% will typically be at the LV network level and 25% at HV (generally 11kV) level[10]. Overall, LV losses typically account for around 45% of total losses and HV losses for around 25%. EHV losses (including 132/33kV transformers and other EHV/EHV variations) account for around 25% of fixed losses and 30% of variable losses; and 30% of losses overall.

Overall, technical losses for GB transmission and distribution networks are estimated to be currently around 7% of the electrical energy produced. Given the current GB annual electricity production of around 350TWh, and assuming 5% technical losses (i.e. net of transmission losses) for distribution networks, the current level of

[8] That is, the paper does not call on actual network modelling but instead bases its evaluation on high-level parameters and rationalised top-down assumptions

[9] Fixed loses do however vary with voltage: a 1% increase in secondary voltage typically produces a 2.5% increase in fixed losses

[10] This apportion includes variable losses on the associated lower voltage windings of transformers

distribution technical losses is approximately (350 x 5%) = 17.5TWh p.a. of which variable losses will be approximately (70% x 17.5) = 12.25TWh.

Drivers for demand growth and future levels of losses

Being a function of several drivers including: energy growth, peak demand growth, load factor, network architecture, network capacity, and the rate at which older high iron loss transformers are replaced with lower iron loss units as a consequence of either condition or loading criteria, and networks are either extended or reinforced to deal with new or additional demand, there are many factors which could impact on network technical losses over the period to 2030. However, making a simplifying assumption that 'conventional' load growth will remain net neutral over this period - i.e. natural network load growth due to increased population, employment growth and additional housing is countered by general churn, higher efficiency-rated electrical appliances, higher energy prices (leading to reduced consumption) and energy efficiency generally - then the additional demand presented to networks (gross of any offset due to DG or micro-generation) would be mainly that due to electrification of heat and transport.

Taking DECC's 4th Carbon Budget scenarios to 2030, and depending on the individual EV and heat pump growth scenarios chosen, EVs could present up to an additional 16.6TWh of demand while heat pumps could present up to an additional 49.5TWh[11] making 66TWh in total. DECC's 4th Carbon Budget scenario 3 would result in both of these additional demands being presented to distribution networks - and almost entirely at the LV network level, meaning that there would be an impact on losses at all network voltage levels. On that basis (and ignoring the additional losses which would need to be supplied) national electricity energy production would need to increase from 350TWh to 416TWh - i.e. an increase of 19% compared with today - to supply the additional demand created by EVs and heat pumps (albeit a contribution would come from micro-generation at the point of use).

In the absence of investment in additional network capacity, then the impact of an additional energy demand of 49.5TWh on network variable (I^2R) losses would be to cause an increase from 12.25TWh to (12.25 x 1.19^2) = 17.34TWh: i.e. an increase of 5.09TWh.

At £60 per MWh, the value attributable to 7.09TWh of additional network losses at 2030 would be £305million p.a.

Impact of new demands on - and relevance of - load factor

In practice, it is unlikely that, at current load factors, a 19% increase in electricity consumption could be accommodated on networks without reinforcement. Such an increase could be accommodated without reinforcement only if all LV networks were operating at no more than 81% utilisation factor and/or that the additional demand was distributed across LV networks in proportion to their capacity headroom; or that electricity demand could be 'reshaped' in order to make use of capacity headroom during lower demand periods. At higher voltages, the need to meet ER P2/6 levels of security would dictate a much lower level of utilisation factor for there to be sufficient capacity headroom to accommodate such an increase.

In other words, avoidance of reinforcement would require that networks were actively managed in order to maintain sufficient capacity (i.e. to prevent thermal overloading and/or statutory voltage transgressions) and that the new demand was actively managed to maximise available capacity during off-peak demand periods. However, if load factors were to become degraded (i.e. demand curves became 'peakier') then capacity headroom would be further eroded and losses would increase even further (and/or even greater reinforcement of existing networks would be necessary).

The effect of electrification of heat and transport on distribution network losses is complex. As illustrated above, without investment in additional capacity, higher levels of electrical energy distributed through distribution networks due to EVs and heat pumps would cause variable losses to increase in absolute (i.e. TWh) terms even if load factor could be improved (albeit DG and micro-generation will generally reduce losses locally provided there is a reasonable level of local load matching). However, if EV charging and heat pump operation - especially in the winter weekday early evening period when demand already peaks and annual SMD occurs - causes network load factors to degrade, then network variable losses will increase disproportionately to the additional energy distributed.

Two key objectives of smart grid operation, facilitated by smart meter data, are firstly to facilitate demand side response (DSR) to counteract any degradation in load factor arising from EVs and heat pumps which might otherwise naturally draw energy from the distribution network at times of peak demand; and secondly to apply active network management to improve load factor through voltage optimisation[12] and load balancing. Typical annual load factors on LV and HV networks will be around 0.35 to 0.4 and 0.45 to 0.5 respectively.

The main objective of maintaining or improving load factor is to preserve network capacity headroom and hence minimise the need for capacity investment. However, DSR enabled through time-of-use tariffs coupled with smart appliances and/or active control of flexible demand also has the potential to mitigate a disproportionate increase in variable network losses (including upstream transmission losses) by encouraging consumers to avoid peak demand periods as far as practicable.

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[11] These figures together represent scenario 3 of DECC's 4th carbon budget scenarios, but scenarios 1 and 2 result in broadly similar increases in consumption

[12] For example, whilst reducing voltage on LV networks would tend to erode diversity (i.e. because the period over which a current **(I)** flowed would need to be prolonged in order to deliver a given quantum of energy **(VIt)** requirement) this should be more than compensated by a reduction in overall peak demand

The mitigating impact of DSR

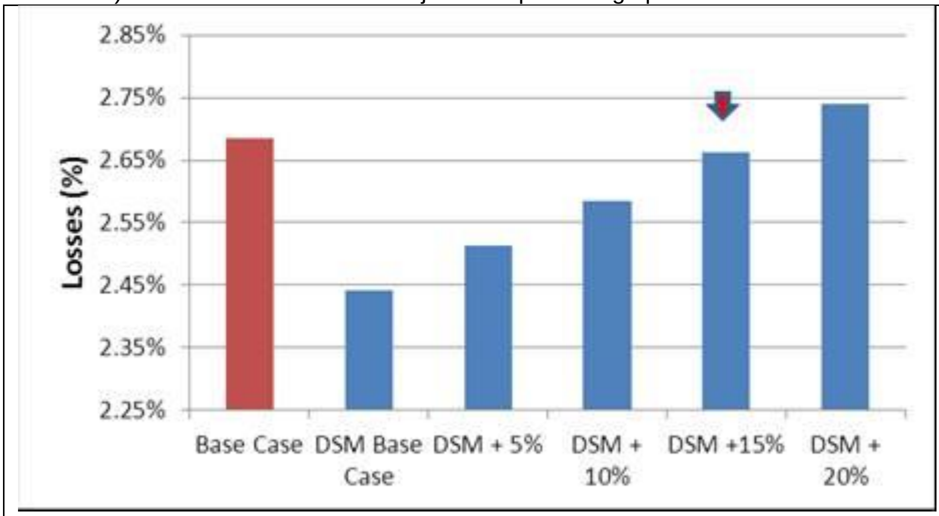
The chart below represents an LV system where the contribution to overall network losses is around 2.68 percentage points. The histogram indicates the theoretical potential for DSM (i.e. DSR) to reduce variable losses for a given level of demand or, alternatively, maintain variable losses at the current level while accommodating an increase in demand. The chart assumes that DSR gives rise to improvements in daily load factor consistent with the findings of the ENA / SEDG / Imperial College Summary Report (Goron Strbac et al) - 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks'

The chart indicates that DSR has the potential to reduce LV system losses by 0.28 percentage points based on current levels of demand, while an additional 17% of energy demand could be accommodated without any increase in LV system losses (i.e. in terms of percentage of energy distributed). Active network management techniques designed to optimise voltage and load sharing, enabled by 'real-time' half-hourly average voltage and energy flow data from the smart meter system, will also have a beneficial impact on distribution networks losses.

Given the above scenario whereby national electrical energy demand increases by 19%: the chart indicates that, by realising the full potential of DSR, losses on LV networks (as a percentage of energy distributed) would increase only marginally - i.e. by around 0.05 percentage points (i.e. comparing the Base Case with DSM+20% case).

Potential savings in losses through DSR

It follows from the above that, in theory, even given the 19% increase in energy demand associated with DECC's 4th Carbon Budget scenario 3, DSR facilitated by smart meters has the potential to minimise the need for network investment in capacity while maintaining losses at a roughly constant level (in terms of percentage of energy distributed) - i.e. an increase of around just 0.05 percentage points.



Source ENA/SEDG

Based on the above chart, assuming that LV network losses continued to account for 45% of total distribution network losses, the level of LV network variable losses required to deliver a 19% increase in energy demand (416TWh) would be 0.45 x 12.25 x 1.05 = 5.79TWh or just 5.79 – (12.25 x 45%) = 0.28TWh above the current level of LV variable losses.

Comparing this with the level of LV network losses without DSR of (17.34 x 45%) = 7.80TWh (from above) this equates to an annual saving in losses of (7.80 – 5.79) = 2.01TWh.

Taking the current valuation of losses at £60 per MWh, the value of DSR in terms of losses reduction at 2030 is therefore 2.01 x 60 x 10^6 = £121million p.a.

Given the quadratic relationship between variable losses and electrical energy distributed through a conductor (i.e. losses = I^2R) then the impact of (say) a linear growth in demand due to EVs and heat pumps over the period to 2030 would be to give rise to an exponential trend in the growth of variable losses. It follows that over the ED2 period, the impact on losses will be much greater than over the ED1 period. Indeed, it is assumed that in any case, DSR will have minimal impact on demand until completion of the smart meter rollout programme in 2020, which is the earliest likely time for introduction of DSR-based tariffs. The table below illustrates the envisaged rollout of benefits (£m) to others over the ED1 and ED2 period (i.e. 2015-2030).

Table 19 Others potential benefit summary through demand side response

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Benefit (£m)	0	0	0	0	10.1	20.2	30.3	40.3	50.4	60.5	70.6	80.7	90.8	100.8	110.9
Discounted (£m)					8.7	16.9	24.4	31.4	37.9	43.9	49.2	54.5	59.2	63.5	67.4
Discounted Cumulative (£m)					87.4	25.6	50.1	81.5	119.4	163.3	212.7	267.2	326.4	389.9	457.2

Taking the calendar year period 2015-2022 as a proxy for ED1 (similarly 2023-2030 for ED2), the ED1 period benefit (non-discounted) is estimated at £60.6million, while the ED2 benefit is £605million.

Caveats and qualifications

In practice, the level of saving will be dependent on the extent to which, in the absence of DSR, LV load factor would vary compared with its current level of around 0.35 to 0.4. The above saving of 2.01TWh is achieved through DSR improving load factor above the current level, despite the potentially degrading impact on load factor of EV and heat pump demand if not subject to a DSR regime. If, on the other hand, DSR had a less beneficial impact on load factor - i.e. because of price inelasticity of electricity and hence practical constraints on flexibility of EV and heat pump demand; or because Suppliers introduce time-of-use tariffs that encourage consumers to match demand more closely to real-time or predicted market prices, irrespective of network constraints - then even under a DSR regime, network load factor might still degrade compared with today.

The focus of this paper has been towards losses on LV networks where the greatest impact of EVs and heat pumps will be felt and where load factor management would be most advantageous - for example in terms of avoiding the need for reinforcement which would be disruptive and expensive (i.e. due to streetworks excavations, the need to transfer service connections, and the need for shutdowns). However, albeit diluted through natural diversity of demand, management of LV network load factor would also have beneficial consequences for upstream network losses.