UK Power Networks

RIIO-ED1

Investment Justification

Load related expenditure

Network: LPN

Version 1.4

Document History

Version	Date	Revision Class	Originator	Section Update	Details
1.4	05/03/2014	Minor	Robert Kemp	1.1	Changed Text to reflect chart changes
1.4	05/03/2014	Major	Robert Kemp	1.2	Table 1 Aligned figures to the19th February 2014 NAMP version J less indirect costs.
1.4	05/03/2014	Major	Robert Kemp	1.2	Change figure 1 to align figures to the 19th February NAMP version J less indirect costs
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1.4	05/03/2014	Major	Robert Kemp	3.4.2	Tables 14,15, changed to reflect to the19th February 2014 NAMP version J less indirect costs; consequential changes to the supporting text

Version	Date	Revision Class	Originator	Section Update	Details
					to reflect new costs ; and removal of scheme detail as this now available in Gate A papers.
1.4	05/03/2014	Major	Robert Kemp	3.4.3	Tables 17,18, changed to reflect to the19th February 2014 NAMP version J less indirect costs; consequential changes to the supporting text to reflect new costs ; and removal of scheme detail as this now available in Gate A papers.
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1.4	05/03/2014	Minor	Robert Kemp	4.1	Update to maximum demand figure for 12/13

Version	Date	Revision Class	Originator	Section Update	Details
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Contents

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V0.1	09/03/2013	Draft Document	Frank Needham
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1.0 Executive Summary

1.1 Scope

This document provides justification for UK Power Networks load-related expenditure for the ED1 period in the London Power Networks area.

It includes a description of our overall strategy for extending and expanding the LPN network. We also describe the assumptions that underpin the forecast, a review of historical spend and an overview of the processes we use to create our forecast expenditure

We include all of the expenditure for LPN for expanding and extending our network driven by general load growth, fault level reinforcement and expenditure driven by third parties wishing to move or develop land near our assets.

1.2 Overview of the LRE plan

Our forecast plan for the period 2015/16 – 2022/23 for Load Related Expenditure in our Network Asset Management Plan totals £434M (excluding betterment and NRSWA). It is phased over the period as shown in Table 1.

This total expenditure is sourced from our Portfolio Investment Management System, which is our business tool. It reports costs at a project level, leading to differences to the regulatory reporting. For example, it may include costs that are ultimately recovered from customer connections.

Based on our planning assumptions that resulting in our forecast demand growth, this forecast expenditure will ensure that we meet our licence obligations, maintain network capability and utilisation and enable new connections for new demand and generation. Table 1 below indicates the forecast expenditure plan for ED1.

	ED1 Expenditure Profile (£000's)								
	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	Grand total
Total	£68,798	£61,312	£66,577	£ 57,754	£56,160	£ 46,741	£39,793	£37,282	£434,408

Table 1: LPN Forecast Plan 2015/16 – 2022/23 for LRE Total £434m (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Figure 1 provides a breakdown of the total ED1 expenditure broken down by NAMP reinforcement lines whilst Figure 2 illustrates how the breakdown evolves by year within the ED1 period.

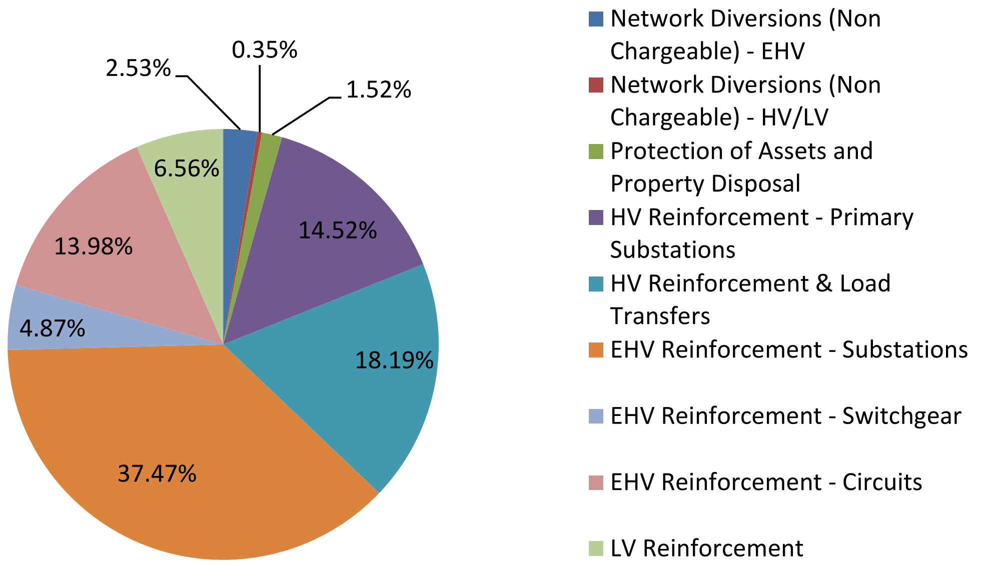

Figure 1: LPN Load Related Expenditure for ED1 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

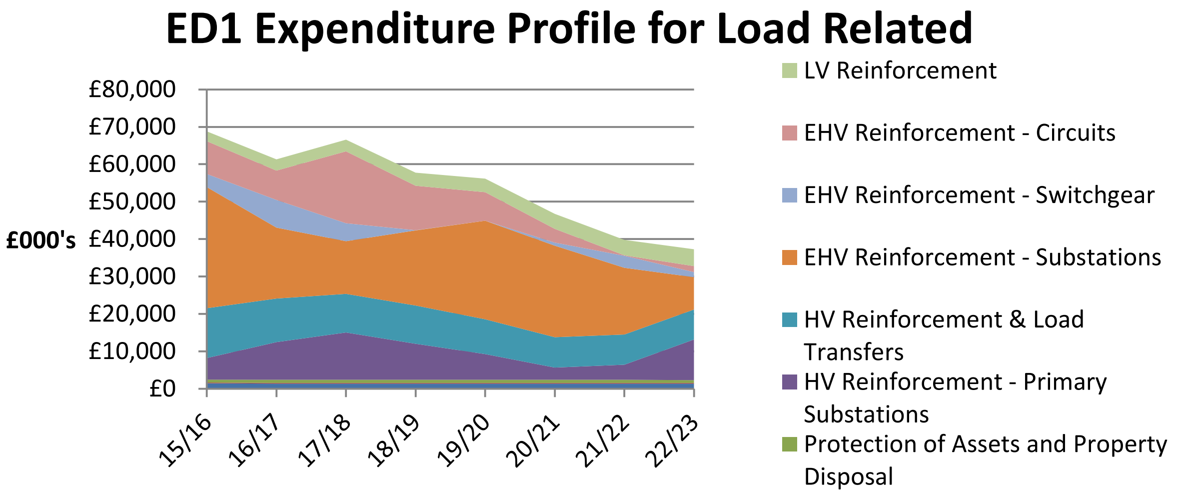

Figure 2: LPN split of the load related activities shown per regulatory year over the ED1 period (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Table 2 below indicates the LRE expenditure, by Category, for the ED1 period.

Category	Total per Category
Network Diversions (Non Chargeable) – EHV	£10,997
Network Diversions (Non Chargeable) - HV/LV	£1,538
Protection of Assets and Property Disposal	£6,613
HV Reinforcement - Primary Substations	£63,084
HV Reinforcement & Load Transfers	£79,012
EHV Reinforcement – Substations	£162,778
EHV Reinforcement – Switchgear	£21,164
EHV Reinforcement – Circuits	£60,721
LV Reinforcement	£28,500
Total	£434,408

Table 2: Total LRE by Category for ED1 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

As a result of this and our planned expenditure we are committing to deliver on a Load Index output. We believe that an approach to maintain a broadly flat profile of LI4/5 sites over the ED1 period best meets our customers' requirements, and we will seek to maintain the number of LI4/5 sites over the long-term. The table below reconciles between our DPCR5 start and new end points, taking into account the change in our demand forecasting process compared to DPCR5. The change in our demand forecast and the changes to LI definitions and banding have changed our forecast start point for ED1 (end point for DPCR5) from 17 LI4/5 sites to12.

DNO	DPCR5 year 0 position	DPCR5 End	Actual 2011/12	Oct 2nd 2012 Ofgem return for 2014/15 forecast	2014/15 Old Forecast latest delivery information	2014/15 New Equivalent Forecast Start ED1	ED1 End Forecast
LPN with investment	28	21	23	27	23	17	12
Old site load growth forecast and DPCR5 LI definitions and banding						New site load growth forecast and new LI definitions and banding	

Table 3: LPN LI4/5 Site figures at the start and end of ED1

A full LI profile for the ED1 period is contained in the LI Index table CV102.

Our LI output target we have set has been informed by feedback from our stakeholders. In general, their view was that there was no appetite for spending more to improve the network above the risk position anticipated at the end of the current period. We generally agree with that view and seeking to maintain a constant level of risk over the longer term delivering investment while continuing to run our network harder than many other DNOs. The figure below shows our Networks utilisation (actual and forecast) over the DPCR5 period versus the industry average (red line). All show that we operate more of our sites at higher utilisation than other DNOs (based on 2011/12 LI data share information for the DPCR5 period). LPN is noticeably higher than our other networks and the proposed investments in London seek to tackle this to help support future economic growth.

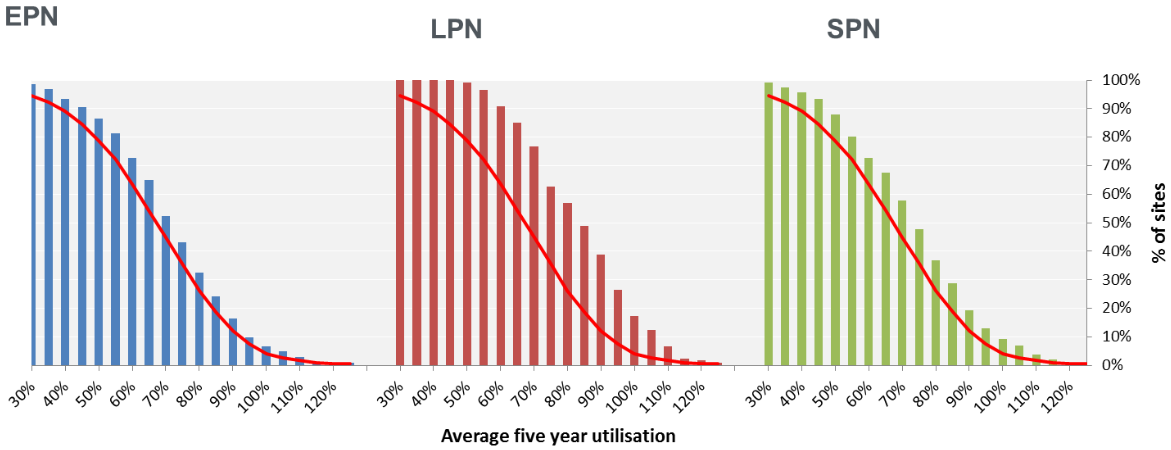

Figure 3: UK Power Networks site utilisation by licensed area

In London, some stakeholders and customers considered that additional investment was required. An area of specific debate has been the future development of London's network infrastructure so that it is appropriate for the UK's capital city. As a result of discussions with Ofgem, who confirmed that the current regulatory framework does not support investment ahead of need investment in infrastructure we have revisited our proposed investments to ensure it fits with stakeholders views and the regulatory framework – these are described in more detail in this and supporting documents.

Our ED1 plan is based on the delivery of the outputs we committed to during the DPCR5 period. We have delivered these while also underspending against the agreed Allowance by £68m (27%). Our customers will benefit from this underspend, receiving 55% back in the next period.

The annual average forecast spend in the ED1 plan is higher than the average spend (actual/forecast) over the DPCR5 period. This reflects the higher demand growth from our Core Scenario demand forecast compared to DPCR5 actual growth. Actual growth has been relatively low at a system level adding approximately 100MW to the peak demand. In ED1 by contrast our system forecast shows a net increase of around 575MW, mostly due to Industrial and Commercial demand (495MW) and small decline in domestic demand (circa 20MW). We translate this into site-by-site peak growth that varies across different areas of the network. The increase in peak load is driven by economic recovery and the uptake in electric vehicles (EV) and (to a lesser extent) heat pumps. The contribution to the annual growth in demand associated with EV and heat pump increases. Over the period to 2023, 17% of the growth in peak demand (at a system level) is due to heat pumps and EVs (circa 100MW). EV's dominate the low carbon technology picture in LPN due to the lack of suitable housing stock, which limits heat pump uptake. We expect this to have a significant impact within this period on the low voltage network where clusters of uptake in these technologies occur, leading to greater reinforcement than has previously been seen for this part of the network.

To accommodate the low carbon technology we are investing in the ED1 period to ensure that we are able to respond given the uncertainty of timing around customer uptake. We are incorporating the enabling technologies for smarter operation of our grids to de-risk the uncertainty, including demand side management and dynamic ratings. (More on our smart innovations can be found in Appendix Section 4.5).

Spend in DPCR5 has been lower than expected due to the timing of major reinforcement projects in London. Major tunnel works connecting the new Wellclose Square and Osborn Street sites have been delayed due to consent delays for the tunnel route. The knock on effect on major projects means spend may now be deferred into the early years of ED1, including commissioning of the Osborn Street reinforcement. As we progress through the ED1 period, the rate of spend falls from 2018/19 towards to more normal levels of forecast reinforcement expenditure during the second half of ED1. These effects and our strategy for future development of our networks are creating greater spend in the final years of DPCR5 compared to the earlier years. (More information can be found in section 3.5).

Of the projects in the final two years of DPCR5, there is approximately £26M of projects that are dependent on customer commitments, £94M has already progressed into design or construction phases with the remaining £25M of forecast spend going into review or approvals.

We believe that our proposed ED1 programme of investments, together with use of smart technologies within our suite of intervention options provides us with carefully balanced flexibility to respond to the emergence of higher penetration of low carbon technologies.

2.0 Planning Process for Reinforcement

2.1 Context

UK Power Networks takes a long-term and regional focussed approach to developing the network. We assess the need to reinforce and expand our network based on previous experience, local knowledge and robust demand growth projections. We take into account long-term trends for our site that recognises the long-term nature of our decisions. This seeks to ensure that at a regional level our plans provide flexibility for a range of possible future developments informed by our stakeholders. We work with our stakeholders to understand both what they want from our network in the future and to capture a broad base of knowledge around the assumptions that underpin our demand projections.

Our network needs to be capable of meeting peak demands of not only an average winter, but also adverse weather conditions such as a 1-in-20 cold winter and other identified critical network loading conditions, e.g. peak summer loadings in central London caused by the increased use of air conditioning.

In addition to load growth arising from familiar economic and housing growth, there is increased uncertainty regarding demand growth and generation deployment over the coming years. These changes are being driven by Government policy on reducing carbon emissions. This is expected to change patterns of electricity consumption and increase demands on our networks from the charging of electric vehicles and use of heat pumps and distributed generation.

2.2 Planning Process

The starting point for all of the reinforcement planning is UK Power Networks long term strategy for managing network capacity: i.e. to run our network more efficiently whilst maintaining a broadly constant level of risk.

This strategy has been informed through the feedback received from our internal and external stakeholders and we regularly measure its success by looking at operational metrics like the LI, CI and CML.

To achieve our long term strategy we undertake a detailed planning process which involves a range of inputs, the use of sophisticated modelling techniques and tools, (which are described in the appendices). We draw on the skill and experience of the planning team to interpret the results from our models in order to provide outputs e.g. optimised projects and our Regional Development Plans (RDPs).

The figure below provides a high level overview of the reinforcement planning process and the steps taken to ensure that the outputs are robust and in line with our long term strategy. The following sub sections describe each step in more detail.

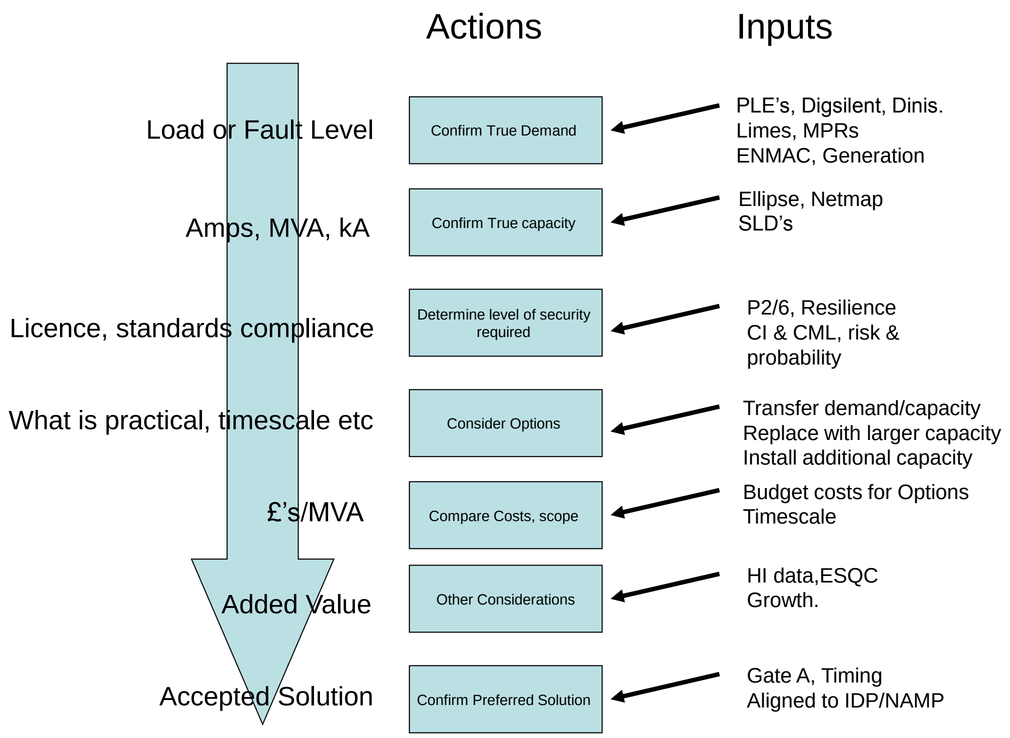

Figure 4: Overview of Reinforcement Planning Process

Forecasting future demand

The prediction of future network demands is a key factor when carrying out a reinforcement assessment. Knowing the existing substation demand, the underlying growth rate and any future demand increases, due to specific known developments, allows a prediction of when a site's or network capacity will be insufficient to support the expected demand.

Climate change, smart metering, penetration of electric vehicles, domestic heat pumps, DG and the UK's low carbon transition are also additional factors that need to be taken into account.

To forecast future demand we have developed a scenario modelling tool in partnership with *Element Energy*. This allows us to model a range of scenarios, combining differing planning assumptions and applying the result at a regional and more granular level to our network areas. The Core Scenario we have selected as a forecast of future demand was formed following work with our stakeholders and is the outcome of that engagement. (See Appendix Section 4.2.5 for more detail on the Element Energy model)

The growth assumptions of the Core Scenario are used as inputs to assess the electricity demand on our network as a whole (through the Imperial College model) and at substation specific level (through the Planning Load Estimator model).

Planning Load Estimates (PLEs) is a site specific model intended primarily as a 'first pass' method of identifying candidate substations for future demand-driven expenditure. Where the PLEs flag a substation as at or close to capacity they will normally be subjected to more detailed study, as described in the 'Substation Load-Related Risk Analysis' process (see Appendix Section 4.8).

PLE data is also used to determine predicted future demand growth at Grid Supply Points (GSP), as required for the Week 28 submissions to National Grid (NG). PLE data is used in various other processes where substation demand information is pertinent and, in particular, for network and system analysis.

The *Imperial College LRE* model (see Appendix Section 4.7) is a top-down system maximum demand process which does not pick out individual site maximum demands that may peak at times different to the system peak demand. This model allows forecasting, using a number of scenarios, beyond ED1 and ED2 such that UK Power Networks can ensure that the proposed expenditure underpins, as far as reasonably possible, likely future scenarios.

The above mentioned models are also complemented by the *Transform* model (Smart Grid Forum, Work Stream Three) which looks into a generic network types nationally to provide an indication of what and how smart solutions could be deployed and indicative financial benefits.

The outputs of the PLE and LRE models provide a robust first-pass assessment of where investment may be needed due to load growth and smart solutions may be possible (the Transform model provides a generic indication of the potential smart benefits from the different technologies – these may be more or less applicable to our networks).

In addition to that our planning engineers confirm the site demand and supplement the general load growth assumptions with local knowledge including:

- The fault level of the equipment supporting the load growth to ensure that the design capability is not exceeded (e.g. for the switchgear);
- The impact of embedded generation which could mask the presence of additional load connected to the network or reverses the power flows when generation supply exceeds customer load;
- The impact of any significant load that is expected to connect to the network.

Confirm capacity

In parallel to the estimation of future demand, our planning engineers assess the firm capacity of each specific point in the network. They do so by looking at factors like the rating of circuits, transformers and switchgear through the use of specific tools like Ellipse (asset database), Single Line Diagrams (SLD) and Digsilent (network modelling tool)

Identify interventions

The forecast demand growth and the firm capacity on the system are used to assess what circuit reinforcement is required.

As previously mentioned our strategy is to run our network more efficiently whilst maintaining a broadly constant level of risk. Part of the objective is therefore to ensure that UK Power Networks is maximising asset utilisation while at the same time managing network design security risk.

Compliance with Engineering Recommendation P2/6 standards, which is part of our License condition, provides a minimum standard to ensure that the network is managed to specified security of supply criteria. We plan to ensure that investments are delivered at the point in time when we expect P2/6 compliance to be at risk.

In addition to that, we also ensure that over the long-term the number of LI4 and LI5 sites on the network is maintained at a broadly constant level over time.

To help identifying which interventions should be prioritised we employ the 'At Risk' process (EDP 08 108) reference to section 4.3.1 to provide a robust assessment of risk on a site-specific basis. We also look at additional factors as further explained in the sub section "Additional considerations" below.

Assess options

Once the interventions schemes have been identified, our planning engineers evaluate the most efficient delivery options taking into account a series of factors, including:

- The nature of the investment driver (e.g. thermal, voltage, fault, distributed generation, etc.);
- The cost of the intervention;
- The benefits accruing from a specific option;
- Secondary benefits (e.g. Quality of Supply improvements through automation, asset health improvements, etc.);

The intervention options are described in detail in Appendix Sections 4.4 and 4.5 that cover the potential applicable options in both traditional and smart technologies.

Additional considerations

When drafting our reinforcement plans we ensure that they are optimised to take into account the interventions driven by drivers like Asset Health and Quality of Supply, and that our options are feasible from a deliverability point of view.

In addition to that, it is important to acknowledge that reinforcement planning is a fluid process.

As the network is managed in real time, new information is collected that could significantly change the drivers underpinning investment plans. For instance, maximum demand data used in our models is updated annually. This ensures that our assumptions are regularly baselined and that investment is undertaken only when effective load growth is taking place.

New information could therefore change our investment plans: i.e. they could be deferred, brought forward or cancelled. The decision to change the investment plan is part of the gateway process described in the following sub-section.

Gateway process

Each step of the process described above is undertaken within strict governance rules and processes. This ensures that the NAMP is:

- Challenged by the relevant decision makers;
- Change controlled;
- Rigorously risk assessed;
- Appropriately documented;
- Properly communicated;
- Effectively implemented.

Please refer to Appendix Section 4.9 for more information.

Regional Development Plans

The outputs from our planning process are brought together by into a single regional view of the needs of the network in our Regional Development Plans.

The Regional Development Plans present the full view of how individual projects work together to address issues associated with the overall network at all voltages. These take a longer term view (20-30 years) of how the network may develop to ensure that it is fit for purpose considering the wide ranging stakeholder views and requirements. These bring our plans together for an area normally based on the network supplied from the interface with National Grid. These are living documents that incorporate the Planning Load Estimates (PLEs) and known proposed customer connections together with local information and provide an overall view of network development.

RDP	LPN
1	Willesden
2	Lodge Road
3	St Johns Wood
4	City Road
5	London 33kV Network
6	North London (Islington/Hackney)
7	Brimsdown-Redbridge
8	East London (West Ham/Barking)
9	Wimbledon
10	New Cross
11	Beddington-Hurst
12	Dartford

Figure 5: RDP Geographic Locations

Within LPN 12 Regional Development Plans have been established. These plans provide a well-engineered, holistic and optimised solution to the challenges presented to our networks.

Specifically, the Regional Development Plans:

- Detail all related issues facing the region, including growth, asset renewal requirements, network constraints and transmission interfaces.
- Identify the possible options for addressing the issues faced.
- Recommend a preferred option, based on a cost benefit assessment, with associated rationale.
- Describe the rationale for the rejected options.
- Identify risks, assumptions, dependencies and sensitivities of the preferred option.
- Detail capacity changes and new/removed assets.
- Indicate DG Capacity.
- Identify remaining Operational and technical constraints

3.0 Overview of our Load Related Expenditure

3.1 Core Scenario

The need to extend and expand our networks is driven by increases in electricity demand. We forecast electricity demand based on a wide range of factors including the number of new households and the rate of economic growth. We have worked with our stakeholders to refine our planning scenarios and have developed innovative models to enable us to take a longer term view. We are also considering how new uses and ways in which people use electricity may impact our networks. We have taken views for the uptake on the more uncertain future demands from low carbon technologies (electric vehicles and heat pumps), how people may respond to tariffs that change with the time of day, and how much renewable generation may be connected to the network. We have based our plans on our best view known as our “Core Scenario” of electricity demand growth and connection of distributed generation, supplemented by our local knowledge of developments that will impact our network.

The Core Scenario demand forecast shows how the uptake in electric vehicles (EV) and heat pumps is much more noticeable towards the mid 2020s. Over the ED1 period the contribution to the annual growth in demand associated with EV and heat pump increases. By 2023, 20% of the growth in peak demand (at a system level) is due to heat pumps and EVs. EV’s dominate the low carbon technology picture in LPN due to the lack of suitable housing stock, which limits heat pump uptake.

To accommodate these it is necessary to invest in the ED1 period to ensure that we are able to respond. The timing of this increase is uncertain and we are incorporating the enabling technologies for smarter operation of our grids to de-risk the uncertainty, including demand side management and dynamic ratings.

Overall, demand growth from Industrial and Commercial (I&C) customers will continue to dominate the underlying driver of most investment in our LPN network. Our forecast shows domestic demand remaining broadly consistent where increases in the volume of appliances owned by customers is offset by developments in energy efficiency.

We have based our plans on our best view known as our “Core Scenario” of electricity demand growth and connection of distributed generation, supplemented by our local knowledge of developments that will impact our network. Figure 6 below provides an overview of demand growth in the LPN area as per our “Core Scenario.

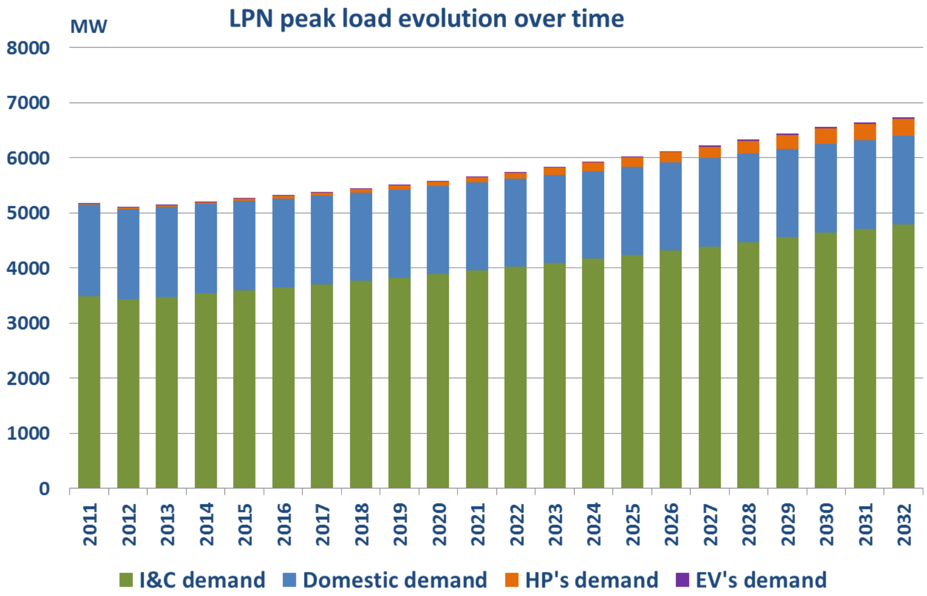

Figure 6: Overview of Demand growth in EPN

We distribute the predicted load growth across our substations, taking into account factors such as the clustering effect of low carbon technologies due to the particular characteristics of location, demographic and housing stock that lead to an irregular distribution of the uptake of these amongst our customers.

We have also evaluated the potential variation in timing of these demands on our network and sought to quantify top-down the investment requirement. We have used our innovative reinforcement investment (ICL) model to investigate the full range of scenarios defined by DECC as part of the Smart Grid Forum process. The range of general reinforcement investment programme this document focusses on our own Core Scenario.

There are two main spend areas, i) diversions and investments driven due to third part actions and ii) general reinforcement spend. Each is described in the sections below. More detailed information on individual High Value Projects and EHV schemes can be found in specific gate A papers scheme papers and regional information can be found in the relevant Regional Development Plan that outlines all investments in each sub-region of our networks.

3.2 ED1 Proposals

The following tables show the spend against the RIGs table lines in CV101. This table contains all the costs associated with the electrical assets. The discussion in this document is at a scheme level, and as such the totals shown for each Network Asset Management Plan table will be higher than the total spend shown in the table below. This is due to other costs that appear in CV105 or CV108. In addition High Value projects are discussed in this document but the spend will appear in RIGs table CV9a.

	Substation reinforcement		DPCR5	DPCR5 8 year	RIIO-ED1	Commentary
		Voltage	(£m)	(£m)	(£m)	
6	Secondary network	LV/LV	0.0	0.0	-	
7	Secondary network	HV/LV	9.6	15.3	29.8	Increase is driven by the introduction of greater remote control on the LV network and the rollout of unit protection to improve performance of HV network (see section on HV reinforcement and load transfers
8	Secondary network	HV/HV	6.3	10.1	2.6	Decrease due to this type of reinforcement typically requiring additional physical space on sites, e.g. extension of switchboards. In growth areas these have largely been exhausted requiring new sites to be established that will release positions in existing switchboards to accommodate future local demand growth (see section on HV primary substations reinforcement)
9	Primary network (n-1)	EHV/LV	-	-	-	
10	Primary network (n-1)	EHV/HV	5.6	9.0	37.6	Increase is largely driven by our programme of reinforcements of the 66kV network reflecting the higher load growth expected in ED1 compared to DPCR5 (see section on HV primary substations reinforcement)
11	Primary network (n-1)	EHV/EHV	2.9	4.6	2.5	Expenditure here is largely consequential from the EHV reinforcement work and is dominated by Finsbury Park feeder reconfiguration (see sections on EHV switchgear and substations reinforcement)
12	Primary network (n-1)	132/LV	-	-	-	
13	Primary network (n-1)	132/HV	31.5	50.5	122.9	The spend here is driven by the development of five new 132/11kV sites to provide greater flexibility for increasing local substation capacity in the future and improving resilience for central London business districts. (see sections on High Value Projects; EHV switchgear and EHV substations reinforcement)
14	Primary network (n-1)	132/EHV	5.4	8.6	5.0	The decrease reflects the strategy of introducing more 132/11kV main substations, that is designed to supply much of the incremental demand directly rather than via the EHV network. (see sections on

						EHV substations reinforcement)
15	Primary network (n-1)	132 /132	9.2	14.7	17.1	The increase in this line is driven by work at Grid Supply Points to facilitate additional capacity at four sites, Willesden, Wandsworth, Wimbledon and Islington that relate to forecasts of increasing demand in major areas of development across Central and North London (see sections on EHV switchgear and substations reinforcement)
16	Primary network (n-2)	EHV/LV	-	-	-	
17	Primary network (n-2)	EHV/HV	-	-	-	
18	Primary network (n-2)	EHV/EH V	-	-	-	
19	Primary network (n-2)	132/LV	-	-	-	
20	Primary network (n-2)	132/HV	0.7	1.2	-	
21	Primary network (n-2)	132 /EHV	-	-	5.9	Spend in this category is largely driven by a single project to maintain compliance with P2/6, n-2 criteria at Wimbledon Grid C
22	Primary network (n-2)	132/132	-	-	18.5	Spend in this category comes from five schemes at Wimbledon, Willesden, West Ham. Wandsworth and New Cross
23	**Total**		71.3	114.1	241.9	The increase in spend in ED1 compared to DPCR5 is related to three main drivers, creating additional capacity via main substation to meet the forecast growth in demand (and the consequential rearrangements to the lower voltage levels); increasing resilience of the network through a change in the architecture of the HV/LV network in the high-load zone areas; and investments anticipated to deal with LV issues revealed by smart meters and the uptake of low carbon technologies.

	Circuit reinforcement - Secondary network	Voltage	DPCR5 (£m)	DPCR5 8 year (£m)	RIIO-ED1 (£m)	
29	Secondary network	LV	9.8	15.6	36.8	The increase in spend in these lines reflects both consequential feeder reorganisations as we introduce new main substations and redistribute demand to the nearest substation. It also reflects the anticipated increase in LV schemes to address latent issues that we expect to be reveal from the smart meter rollout and to support the growth in low carbon technologies that is forecast towards the end of the ED1 period (see section on LV reinforcement and HV reinforcement and Load transfers)
30	Secondary network	LV				
31	Secondary network	HV	17.2	27.5	43.9	
32	Secondary network	HV				
33	**Total**		27.0	43.2	80.7	
34						

	Circuit reinforcement - Primary network	Voltage	DPCR5 (£m)	DPCR5 8 year (£m)	RIIO-ED1 (£m)	Commentary
40	Primary network (n-1)	EHV	0.1	0.2	9.2	The increase in spend on Primary network circuits is largely due to a single large project where we are reinforcing the Lodge Road to Carnaby Street cables, as well as ongoing reconfiguration of the 132kV circuits including for the new Islington GSP as part of the short-term plans for increasing resilience and reinforcement of the West End of London. (see EHV reinforcement circuits section)
41	Primary network (n-2)	EHV	-	-	-	
42	Primary network (n-1)	132 kV	5.8	9.3	6.9	
43	Primary network (n-2)	132 kV	-	-	1.7	
44	**Total**		5.9	9.5	17.8	

	Voltage regulation schemes	Voltage	DPCR5 (£m)	DPCR5 8 year (£m)	RIIO-ED1 (£m)	Commentary
50	Secondary network	LV		-		The historical basis for this forecast currently shows no expenditure in DR5. The increasing penetration of PVs and other low carbon technologies on the LV network will create greater supply quality issues. The roll out
51	Secondary network	HV		-		
52	Primary network (n-1)	EHV		-		
53	Primary	132		-		

	network (n-1)					of smart meters is also expected to lead to a number of voltage complaints which will allow the DNO to take action before a customer makes an enquiry. This line will be reviewed as the smart meter roll out gathers pace.
54	Primary network (n-2)	EHV		-		
55	Primary network (n-2)	132		-		
56	**Total**		-	-	-	

DSM payments *(into subscriptions)*

		DPCR5	DPCR5 8 year	RIIO-ED1	
		(£m)	(£m)	(£m)	
62	LV	-	-	-	Increasing utilisation of DSR for supporting reinforcement works, de-risking construction outages
63	HV	0.5	0.7	1.7	
64	EHV	-	-	-	
65	132 kV	-	-	-	
66	**Total**	0.5	0.7	1.7	

	Fault level Reinforcement Schemes: Fault issues on switchboard/substation busbars		DPCR5	DPCR5 8 year	RIIO-ED1	
			(£m)	(£m)	(£m)	
121	**All Scheme Types**	**All**	0.5	0.8	0.3	This scheme is for a reactor at Verney road.

	Fault level reinforcement schemes: Fault level issues excluding switchboard/substation busbars		DPCR5	DPCR5 8 year	RIIO-ED1	
			(£m)	(£m)	(£m)	
127	**All Scheme Types**	**All**	-	-	-	

Table 4: RIG's mappings to CV101 lines

Table 5 shows the spend against the RIGs table lines in CV1 (lines are not shown where there is no spend or are not covered in this document). The discussion in this document is at a scheme level, and as such the totals shown for each Network Asset Management Plan table may be different to the total spend shown in the table below depending on how costs are allocated to against the RIGs definitions.

RIGS table: CV1		DPCR5	DPCR5 8 year	RIIO-ED1	
Diversions (non-fully rechargeable)	Voltage	£m	£m	£m	Commentary
Conversion of wayleaves to easements, easements, injurious affection	LV	0.0	0.3	0.0*	Refer to section on Defence of assets and diversions section for more details *note there is £40k per year expenditure but due to rounding it show's zero
Conversion of wayleaves to easements, easements, injurious affection	HV	0.4	4.6	0.6	
Conversion of wayleaves to easements, easements, injurious affection	EHV	0.1	0.8	0.1	
Conversion of wayleaves to easements, easements, injurious affection	132kV	0.1	0.8	0.1	
Diversions due to wayleave terminations	LV	0.2	0.4	0.8	
Diversions due to wayleave terminations	HV	1.9	3.0	0.7	
Diversions due to wayleave terminations	EHV	1.7	2.7	7.1	
Diversions due to wayleave terminations	132kV	0.7	1.1	3.9	

Table 5: RIG's mappings to CV1 lines

The following sections describe our investment plans in more detail, starting with Diversions and other wayleave related costs associated with the maintaining our assets on third party land.

3.3 Diversions and other investment due to third party action

3.3.1 Context

UK Power Networks manages a complex electricity distribution network operating at various voltages ranging from 132kV down to 400/230V

The majority of the LPN underground cable network is located within the public highway, but where it crosses third party land the network is generally held on the basis of a wayleave agreement. As a result, the network remains at risk from development occurring over, under and in close proximity to electric lines. This risk will be further exacerbated as the UK economy picks up and the need for development increases.

Where a termination notice has been received, it is generally possible to reach a mutually acceptable agreement with the landowner, which can involve expenditure in terms of assets being moved (diversion) or compensation being paid in return for a permanent easement (defence of assets). If a negotiation does not succeed or there is a clear advantage in adopting a different approach then this is included in diversions, i.e. where we spend money to modify our assets.

In extreme circumstances where a diversion is technically complex or unsustainably cost efficient and it is not possible to reach agreement. Little option remains other than to exercise the rights under the Electricity Act 1989 and refer the matter to DECC for a determination. Where successful in defending a case for the network to remain in situ, the matter is referred to the 'Land Tribunal' to determine the appropriate level of compensation. UK Power Networks would simply be granted a termed, generally 15 years, wayleave, for the network to remain in situ and would have to pay a determined level of compensation. At the end of the termed period, the entire exercise would be repeated and the same costs expended. Utilising its statutory powers to protect its assets, although provides immediate security for its network, is an expensive exercise to undertake to protect an asset for a short duration of its total design life. UK Power Networks has seldom exercised its statutory powers, reserving them for extreme cases where the network is of local, if not national, significance. There is an expectation that instances will increase over the duration of the ED1 period as its network is increasingly impacted by construction activity.

Situations do arise whereby development has already taken place and, as a result access to the network for safety, maintenance or replacement purposes is restricted. Where this has occurred little options remain other than to relocate the asset. Due to the nature of the pre-existing consent it is not, generally, possible recoup these monies back from the developer. Where the network is diverted, UK Power Networks will seek to retain as much of the diverted network as possible on terms of a permanent right, i.e. easement or a freehold interest, to minimise the potential for successive terminations on the same section of network.

An increase in funding has been identified for ED1 to acknowledge the expectation that the number of lease renewal notices, under Section.25 (Landlord & Tenant Act 1954 Part 2) will increase over the duration of the next 10 - 20 years. This is borne out by the fact that increasing numbers of the substation leases, acquired by the former distribution network operators, are presently 'holding-over' on expired terms or will expire over the ED1 period. Increasingly, local authorities or large institutional property owners are seeking to re-negotiate, en bloc, the terms of the original lease. This is particularly relevant in the current economic climate to raise additional financial revenue. The terms of the original lease would, generally, allow for the rental to be at nominal consideration, between a peppercorn and £5 per annum, whereas today there is an expectation for the Distribution Network Operator to pay a commercial market rent to remain in occupation. LPN is currently negotiating with LB Islington, LB Hammersmith & Fulham as well as large institutional landowners on the terms of future substation leases.

Typically, today, a rent for a LPN distribution substation would range between £500 to £2,000 per annum with the addition of upward only rent review clause, generally every 5 years, tied to the RPI index. As the availability of land becomes increasingly scarce in our urban environments land prices will increase and, as a result, it is expected that rental values will increase over the duration of the ED1 period and beyond. Where it is possible and justifiable UK Power Networks will seek the freehold interest in its property interests to secure the long term security and viability of its property portfolio.

3.3.2 Network Diversions (Non-Chargeable) – EHV and HV/LV

ED1 forecast

Our ED1 forecast for 132kV/EHV HV/LV diversions and defence of assets is £19.1M and is £11.1M higher than historical spend (on an 8 year equivalent basis).

Table 6 provides an overview of the ED1 forecasted expenditure by NAMP line

NAMP line	DPCR5 £k (8 year equivalent)	ED1 £k	RIGs Table and Line (s)
1.11 - Network Diversions (Non-Chargeable) – EHV	3,800	10,997	CV1 8-9,13-14
1.12 - Network Diversions (Non-Chargeable) – HV/LV	3.398	1,538	CV1 11-12
1.16 - Defence of Assets	842	6,613	CV1 6-9

Table 6 (Source Table J less indirects from 19th of February 2014 NAMP Baseline) Note HV/LV diversions were reported in DPCR5 under 1.16, therefore the total of the 1.12 and 1.16 lines should be considered when comparing costs between periods)

There are currently no known 132kV/EHV diversion projects in our forecast plan and the expenditure is based on recent historical spend. That shows a normal 132kV diversion costs around £1.0-£1.5M. We have assumed one EHV diversion per year and one 132kV diversion every 3 years over the 8-years of ED1 giving the total spend in this category. We believe this is conservative works over the ED1 period will be greater due to the economic recovery and there is more wayleave terminations to accommodate developments e.g. Northern Line extension, large housing, and commercial developments such as at Battersea.

We have based our ED1 spend for HV/LV diversions in LPN on historical spend (note that historical spend on this activity was included in line 1.16). Our ED1 forecast includes a budget provision of £0.19M per year for these events.

For Defence of Assets, we are forecasting an increase in the costs compared to history. We are aware that number of Section 25 lease renewal notices (Landlord & Tenant Act 1954 Part 2) is likely to increase over the next 10 - 20 years as leases obtained in the 1960’s are coming up for expiry. Many Local Authorities serve notices en bloc, particularly in the current economic climate, to raise additional finance. The increase that is being looked for is large; from existing lease payments of 5 pence to £5 to new payments of £500 to £1,200 with exceptions of £4000 being paid annually.

Table 7 below illustrates the additional risks and opportunities that could materially affect the forecast

Risks
Expenditure based on historical trend. An upturn in economic activity could increase expenditure. As more assets require moving to allow developments to proceed.
Land Agents becoming more aggressive on wayleave terminations
Increasing fault activity due to higher utilisation of the assets
Land agents/owners, having maximised 132kV claims are looking for a greater return on any other assets on their land
Changes in Legislation which increase the number of claims (Section 44 Land Compensation Act) reference to the Upper Chamber of Lands Tribunal
Opportunities
Negotiate retention
To optimise other projects into any required diversion.
Improve CI/CML performance regarding circuits following diversion
Realise circuit capacity reinforcement as part of diversion
Seek to Purchase distribution sites when leases expire
Pro-actively secure deeds for high risk & urban network

Table 7: Risks and Opportunities potentially affecting the forecast

3.4 General reinforcement investment

We describe our investment plan in terms of the key programmes of work at three voltage levels on our network, 132kV/EHV ('EHV'), HV and LV and High Value Projects (HVP).

UK Power Networks considers it a matter of national importance to ensure that the resilience of its networks serving key strategic areas, such as central business districts (CBDs), is sufficient to ensure a rapid restoration of supply, with minimal disruption to business activities in the event of a 'high impact event'. We have has identified three CBDs (London City, Canary Wharf and Westminster Mid-Town) which, in gross value added (GVA) terms, jointly contribute some £32bn annually to the British economy. In the (albeit improbable) event of a major disruption to electricity supplies affecting these three CBDs, it is estimated that the loss of GVA would be approximately £1.2bn for London City and £0.8bn for Westminster Mid-Town. These events are called high impact, low probability (HILP).

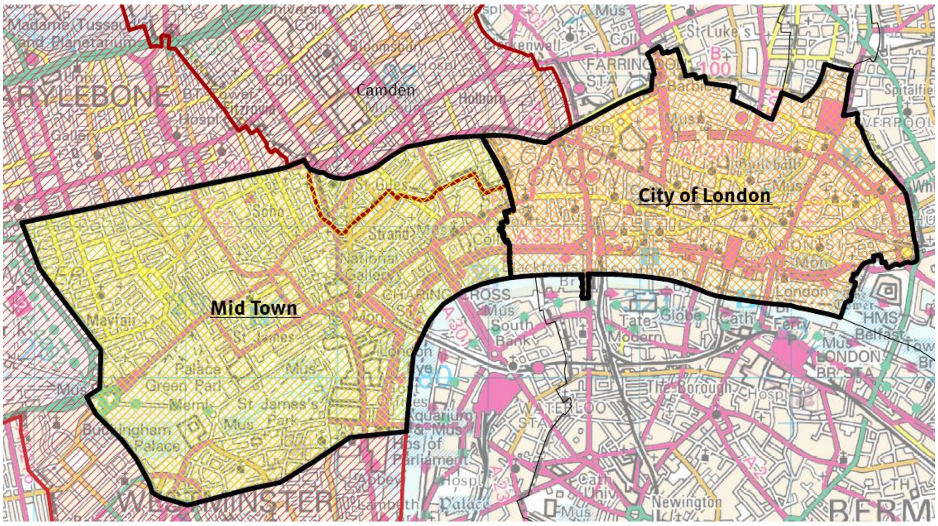

Figure 7: Mid Town and City of London CBD's

We are also aware of our responsibilities to ensure that London's electricity network is fit for purpose and comparable to other world cities in terms of resilience, quality of supply, and the ability to deliver new connections based on the independent benchmarking exercise that we have undertaken. The results are shown in table 8 below, that for London's central business districts we are falling behind in the service we provide. London needs reliable and modern infrastructure to maintain its position against other competing global cities over the long-term. The investments proposed in ED1 support that goal in the long-term interests of customers and wider stakeholders.

	Osaka	Hong Kong	Sydney CBD	Melbourne CBD	London CBD
Interruptions (CI) caused by LV outages	0.10	4.83	3.07	4.97	10.79
Interruptions (CI) caused by HV outages	2.97	9.83	5.48	17.27	16.17
Time to restore following LV outages (CML)	0.21	0.10	9.58	7.86	29.53
Time to restore following HV outages (CML)	0.91	0.27	8.42	12.82	7.17

Table 8: Comparison with other Global Business centres

Our business plan proposes investment in capacity through three new main substations, increased resilience using both more remote control at HV and LV, and a trial of unit protection at four Central London sites, as part of our strategy for closing the gap to other world cities.

Our forecast investment plans will add significant network capacity in London, to meet growth in load from existing customers and to enable new connections. This capacity increase includes the three proposed new main substations that aim to support key growth and development areas in London:

- Vauxhall-Nine Elms-Battersea (Wimbledon RDP)
- White City (Willesden RDP)
- West End (Lodge Road/St Johns Wood RDP- location to be determined, initial discussions with Westminster Council)

These new substations will facilitate the substantial forecast load growth in these areas, reduce connection times and costs, and avoid the need for long cable lengths to other main substations and the associated consequences of cost, street works disruption and higher fault rates. However since the main beneficiaries of the new capacity from these substations would be new connection customers we believe it is fair to existing customers to charge new connections for their proportionate share of the capacity in these substations, even if they connect after the substations have been constructed. The Vauxhall-Nine Elms-Battersea and West End substation projects are described in more detail in the scheme Gate A papers.

In addition to this, we plan to invest in increased automation and remote control to improve quality of supply further. We propose to install remote control at HV substations in the Central London area, and at all the circuit breakers on the low voltage network in the central London area. The specific investments to support this are described in the relevant categories below and in the section on High Value Projects.

3.4.1 EHV Reinforcement – Substations

Investment drivers

EHV reinforcement encompasses a range of activities including major projects such as or 132/11kV transformer installation / replacement at existing sites or the establishment of new substations.

The primary investment drivers for this expenditure category are:

- Installation of new 132/11kV sites is the main driver of expenditure;

- Additional numbers of National Grid Exit Points have the effect of decreasing the impedance (i.e. resistance) on the upstream circuit. On the other hand the distribution network at 132kV level is designed to cope with the previous impedance factor. The effect is an increase in fault levels in the distribution network.

Establishing 132kV substations requires long term planning and investment over many years and cannot be delivered without appropriate planning and consultation. Nor can such projects be mothballed and resurrected quickly;

- Many grid sites are equipped with 3x60/66MVA 132/33kV transformers with little cost effective means to expand further due to a variety of factors such as:
  - space availability, i.e. there is no physical space to accommodate and additional transformer;
  - circuit ratings, i.e. to keep the N-1 rule switchgear will have to be installed on the upstream circuit,
  - and faults levels, i.e. adding an additional transformer will require changes to the downstream circuit (e.g. a new busbar)

  In addition to that, overloaded sites tend to be close to each other. In these cases, it is often more efficient to transfer some of the load of the two overloaded substation to a newly built site rather than trying to expand the capacity of the existing sites that have reached their maximum scale threshold;

- New housing built to modern regulations will have different load profiles. With an increase in the use of direct acting electric heating the expectation is that winter substation peak demands will increase as this traditionally occurs between 5.30-6.30pm as customers return home from work.

These aspects will impact on the shape and magnitude of future load, especially in urban or newly developed areas. Given the lead time necessary for EHV reinforcement, we ensure that our plans are designed to take into account these factors.

ED1 forecast

Our ED1 forecast is £162.8M for EHV substation reinforcement schemes, and is £28.6M higher than the DPCR5 expenditure on an 8 year equivalent basis.

Table 9 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Table and Line (s)
1.35	134,130	162,778	CV101 11 CV101 13-15 CV101 20-22 CV101 52-55

Table 9 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

In LPN this category constitutes the major part of the reinforcement activity due to the high utilisation of existing substations, the requirement for additional capacity, points of connection for new customers and the redevelopment of several areas such as Vauxhall – Nine Elms - Battersea (VNEB) and White City. The list of the 132kV schemes (and the forecast expenditure in the ED1 period) includes:

New sites

The need for the new 132/11kV substations above is to facilitate the substantial forecast load growth in these areas. Further discussion of the specific drivers and situation for the greater than £25M projects are found later in the section on "High Value Projects", and for the other projects further information can be found below.

GWPID	Project ID	Description	ED1 £k
1.35	5815	VNEB New 132/11kV Substation - (2x66.6MVA) **HVP**	25,815
1.35	3668	Wellclose Square New 132/11kV Substation - (3x33.3MVA)	17,711
1.35	5842	White City New 132/11kV Substation - (2x33.3MVA)	13,476
1.35	5799	Eglinton New 132/11kV Substation - (2x66MVA)	10,565
1.35	2635	Shorts Gardens - Replant as 132/11kV Substation (3x33.3MVA)	10,351
1.35	5795	Calshot Street: Establish 2x66MVA 132/11kV Substation	7,069
1.35	6111	Wellclose Square New 132/33kV Substation - (2x60MVA)	3,434
1.35	3724	Islington: Establish New 400/132kV GSP	2,787

Table 10: Schemes over £1M (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Further information on all the above schemes can be found in the relevant High Value Project paper or Gate A paper and RDP.

Reinforcement of existing sites

The identified schemes require reinforcement during the ED1 period due to forecast growth leading to demand exceeding the firm capacity of the site.

GWPID	Project ID	Description	ED1 £k
1.35	2579	Eltham Grid: Install 4th 132/33 kV Transformer	1,606
1.35	4252	Edwards Lane 66/11kV - ITC (add 2x30MVA)	1,807
1.35	8490	Aberdeen Place B 132/11kV - ITC (add 1x30MVA)	1,310
1.35	3657	Hearn Street - Replant as 132/11kV substation (2x66.6MVA)	12,849
1.35	3659	King Henrys Walk - Replant as 132/11kV substation (3x33.3MVA)	10,714
1.35	4367	Hatchard Rd - Replant as 132/11kV substation	12,095

		(2x66.6MVA)	
1.35	5741	Waterloo Road - Replant as 132/11kV (2x66.6MVA)	13,177
1.35	6104	New 132/11kV Substation in Hoxton area (replacing Whiston Road) - (2x33.3MVA)	10,317
1.35	6333	Wimbledon Grid C 132/33kV - ITC (2x90MVA) (N-2)	6,572

Table 11: Schemes over £1M (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Further information on all the above schemes can be found in the relevant Gate A paper and RDP.

The addition of new and expanding sites means we have periods where we have to run the system at lower security. This is particularly an issue in LPN where we continue to see a fast pace of development of land and hence load growth. The demand profile continues to be increasingly flat across the seasons making it more difficult to gain access to the system for big construction projects. We have identified that in these situations there is a potential benefit to reduce the risk of energy not supplied from entering into bilateral DSR contracts. These can be used in these circumstances to manage the risk due to relatively high (but short duration) demand peaks above firm capacity. In the LPN ED1 forecast plan DSR is used to mitigate energy at risk when reinforcement work is proceeding at substations and can supress demand to allow working outside traditional (increasingly short) outage windows. There is significantly less scope in LPN to use DSR to defer investment due to the rate of load growth and the relatively small size of DSR (2-5MVA) opportunities.

The table below shows the DSR interventions proposed for ED1.

Substation	NAMP Reference	MVA	Start Year	ED1 DSR payments (£k)	Years deferred	Reason
Whiston Road	1.35.05.8554	5.0	2021	150	n/a	Mitigating the impact during the replanting of the station to create the new substation at Hoxton by reducing loading e.g. to widen outage windows
Moscow Road	1.35.05.8556	5.0	2015	150	n/a	Mitigating impact during replanting to increase capacity at the site by reducing loading e.g. to widen outage windows
Wimbledon Grid	1.35.05.8557	5.0	2015	300	n/a	Mitigation of impact during replanting of the Wimbledon substation by reducing loading
Wandsworth Grid	1.35.05.8558	5.0	2015	225	n/a	Mitigation of impact during the switchgear reinforcement of the Wandsworth substation by reducing loading

Eltham Grid	1.35.05.8559	5.0	2013	150	n/a	Mitigation of the risk of higher load growth while new 132/11kV Eglinton is built by 2017
Hyde Park A	1.35.05.8560	5.0	2013	300	n/a	Mitigates the risk of load growth while West End is built in 2019
St Pancras A and B	1.35.05.2576	5.0	2013	150	n/a	Mitigates the risk of load growth while Islington is built and the St Pancras substation is upgraded to 132kV
South Bank	1.35.05.8562	5.0	2019	300	n/a	Creates flexibility to defer reinforcement into ED2 due to risk of higher growth from connection activity and a range of developments in the local area, e.g. at Waterloo

Table 12 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Where we successfully enter into DSR contracts with customers, it will mitigate risks in highly loaded areas of London and planned reinforcement of one or two primary substations beyond the end of the ED1 period.

Table 13 below illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in activity could increase load.
Network-wide load increases may require interventions on adjacent sites within the same time period.
Planning permission requirement. Consents required for new assets.
Delays to a project can affect the ability to connect new customers
Opportunities
Removal of high HI plant
New exit points and Grid sites will allow better interconnection and thus the ability to transfer load if needed.
Early discussions with Planning Authorities and landowners will enable sites to be agreed and reduce delays when work is needed.

Table 13: Risks and Opportunities potentially affecting the forecast

3.4.2 EHV Reinforcement - Switchgear

Investment drivers

EHV switchgear reinforcement encompasses the installation, uprating or replacement of EHV and 132kV switchgear with higher rated assets able to withstand higher demand, fault current or to provide sectionalisation of circuits to reduce the number of customers lost (CI) and to provide rapid restoration of supplies (CML) following an unplanned interruption.

Resolving potential overload conditions at EHV level is necessary to maintain a broadly constant level of network risk as measured by the LI metric at the end of the regulatory period. A number of 132/33kV Grid substations have firm capacity limited by the rating of the switchgear.

ED1 forecast

Our ED1 forecast is £21.2M for EHV switchgear reinforcement, which is an increase of £8.2M when compared to our DPCR5 expenditure on an 8-year equivalent basis. The majority of the spend in this areas; some £13.0M is for one schemes, to replant Wimbledon 132kV switchboard.

Table 14 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Table and Line (s)
1.36	13,000	21,164	CV101 11 CV101 15 CV101 18 CV101 22 CV101 40-43 CV101 113 CV101 117

Table 14 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

The work at Wimbledon is to change switchgear to utilise the increased capacity at National Grid's exit point and provide additional bays for new circuits to Wandsworth. This requires the replanting of the existing switchgear with a gas insulated type that uses less space. This will allow the connection of three additional circuits to a new 132kV switchboard at Wandsworth. This will allow us to redistribute existing loads and simplification of circuit arrangements by removing tee-points from the existing Wimbledon to Wandsworth circuits.

The majority (£5.1M) of the remainder of spend in the period is scheduled towards the end for work at exit points in relation to additional Super Grid Transformers by National Grid.

GWPID	Project ID	Description	ED1 £k
1.36	3730	Wimbledon 132kV GSP - 132kV Circuit Breaker Replacement	12,998

1.36	6327	West Ham 132kV GSP - 5th SGT (240MVA) (N-2)	4,536
1.36	6156	Finsbury Market B 33kV Feeder Reconfiguration	1,139

Table 15: Schemes over £1M (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Further information on all the above schemes can be found in the relevant High Value Project paper or Gate A paper and RDP.

Table 16 below illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in economic activity could increase load.
DG penetration affecting fault levels
Increase penetration of generation at a distribution network level
Impact of transmission network reinforcement and changes to the 400/275kV network topology
An upturn in activity could increase load.
Opportunities
Removal of high HI plant
Increase capacity and fault level headroom to connect further customers
Provision of remote control facilities to the EHV network

Table 16: Risks and Opportunities potentially affecting the forecast

3.4.3 EHV Reinforcement – Circuits

Investment drivers

EHV circuit reinforcement encompasses the installation, uprating or replacement of EHV and 132kV underground circuits with higher rated assets able to withstand higher demand current, to allow for a higher utilisation of existing circuits or provide additional circuits to increase network security.

These schemes are focussed on providing interconnection between Grid substations, thereby increasing network resilience. High costs arise in developing these schemes as street level access is increasingly complex and time consuming due to restrictions on road access, railway crossings thereby leading to the development of more and more cable tunnels.

ED1 forecast

Our ED1 forecast is £60.7M which is a decrease of £21.4M when compared to our DPCR5 expenditure on an 8-year equivalent basis

Table 17 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Table and Line (s)
1.37	82,083	60,721	CV101 10 CV101 17 CV101 40-43

Table 17 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

For EHV circuit reinforcement including spend on High Value Projects associated with the tunnel to connect the cables from the existing Lodge Road site to a new West End substation. In the DPCR5 period we undertook significant work in constructing new tunnels which accounted for approximately £45M (including forecasts); whereas in ED1 tunnelling works are forecast at £33M, some £12M lower than for DPCR5.

The schemes in this category are shown in the table below. With the majority of the spend relating to schemes, including works at Wandsworth Grid, the reinforcement of the Lodge Road to Carnaby Street circuits which are required to support the capacity expansion to meet the growth in the local areas, interconnection between Finsbury Market Street and Osborn Street and the Hackney - Waterloo Rd cable tunnel. More information on the schemes can be found in the relevant High Value Project paper or Gate A paper and RDP.

Table 18 provides an overview of the ED1 forecast expenditure for all schemes with £1M of expenditure.

GWPID	Project ID	Description	ED1 £k
1.37	3667	Wandsworth Grid 132/66kV Group Reinforcement	10,429
1.37	5591	Finsbury Market: Establish 132kV Interconnection to Osborn Street	4,896
1.37	8371	New Cross to Bankside - Third 132kV Circuit	1,726
1.37	1270	New Cross - Wellclose Square Cable Tunnel Construction_JN Feb 2013 (ED1 Costs Only)	2,640
1.37	6106	New Cross-Osborn Street - Install 3x132kV Circuits (ED1 costs)	1,524
1.37	8340	Hackney - Waterloo Rd Cable Tunnel	15,560

1.37	8343	Construct Lodge Rd to West End Cable Tunnel **HVP**	14,447
1.37	8637	Lodge Rd-Carnaby Street - Replace 4x66kV circuits	9,184

Table 18: Schemes over £1M (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Table 19 below illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in economic activity could increase load.
Health data is incomplete (e.g. previous fault history, location and lengths of replacements not recorded).
Consents required to lay new circuits
Opportunities
Removal of high HI plant
Interconnection across historic boundaries will increase resilience.
Uprating for reinforcement may assist in the reduction of faults

Table 19: Risks and Opportunities potentially affecting the forecast

3.4.4 HV Reinforcement – Primary Substations

Investment drivers

HV reinforcement at Primary substations encompasses a range of activities including major projects such as 33/11kV or 66/11kV transformer installation / replacement, 11kV switchgear replacement as well as other minor projects such as 11kV transformer tail replacement or additional transformer cooling, and rationalisation of voltage levels.

Resolving substations potential overload conditions is key to maintaining a reasonable LI profile by the end of the period. Primary reinforcement is also required in order to maintain P2/6 compliance, protect plant from damaging overloads, prevent large scale loss of customers (CI), enable rapid restoration following an unplanned outage (CML) and manage fault levels.

ED1 forecast

Our ED1 forecast is £63.1M for HV reinforcement – Primary substations. This is £43.7M higher than our current forecast spend in DPCR5 (on an 8-year equivalent basis).

Table 20 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Code Table and Line (s)
1.33	19,352	63,084	CV101 8-10 CV101 13 CV101 16-17 CV101 20 CV101 63 CV101 117

Table 20 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

The largest single project in this category of spend is works associated with the new West End substation. In ED1 we are forecasting £22.6M from total project cost of £29.3M - the remainder will be spent in the current period. This project is further described in the associated High Value Project Gate A paper. The schemes that make up the forecast are shown in the table below, with further details in the appropriate Gate A scheme paper and RDP's.

Table 21 provides an overview of the ED1 forecast expenditure.

GWPID	Project ID	Description	ED1 £k
1.33	2638	Silvertown 66/11kV - ITC (add 2x33.3MVA)	5,016
1.33	4322	Verney Rd 66/11kV - ITC (add 2x22.5MVA)	3,909
1.33	4349	Carnaby Street 66/11kV Phase 2 - ITC (4x33.3MVA)	3,015
1.33	5744	Lithos Road 66/11kV - ITC (add 2x15MVA)	12,169
1.33	6332	Clapham Park Rd 33/11kV - ITC (add 2x30MVA)	6,028
1.33	8492	Kimberley Rd 22/11kV - ITC (add 2x15MVA)	4,947
1.33	8495	Brixton B 33/11kV - ITC (add 1x15MVA)	1,436
1.33	8496	Wandsworth Central 66/11kV - ITC (add 2x15MVA)	2,963
1.33	6158	Ludgate Circus: Establish 11kV Satellite Switchboard	1,691
1.33	6105	West End New 66/11kV Substation - (3x33.3MVA) **HVP**	22,600

Table 21: Schemes over £1M (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

The majority of the interventions for ED1 will have an impact in terms of LI outputs.

Table 22 below illustrates the additional risks and opportunities that could materially affect the forecast.

	Risks
	An upturn in economic activity could increase load.
	Further migration of night time load.
	Air Conditioning penetration increasing summer peak demand.
	Small embedded generators ability to withstand disturbances on the distribution system.
	Visibility of embedded generation at HV and LV
	Impact of embedded generation to the demand profile at a substation level
	Supply Companies pricing signals shifting the demand peak moving time of day loads.
	Opportunities
	Removal of high HI plant
	Supply Companies pricing signals moving time of day loads.
	Optimally sited embedded generation available when needed offsetting reinforcement.
	The increased use of DSR, DLR and DTR.
	Optimizing the demand profile to increase daily utilization of the network (peak demand management)
	Modernise HV switchgear and build up fault level headroom to enable connection of generation and demand customers
	Provision of remote control facilities on the HV networks at a Primary feeder level
	Reinforced Primary substations provide additional points of connection to enable the direct connection of HV generation
	Replacement of transformers with units that allow reverse power flow and enable further connection of new generation.
	Increased 11kV resilience and transfer capacity.
	Additional remote control and monitoring functions.

Table 22: Risks and Opportunities potentially affecting the forecast

3.4.5 HV Reinforcement and Load Transfers

Investment drivers

HV reinforcement and load transfers include underground cables with greater capacity routes and provision of additional 11kV circuits to improve transfer capacity.

Many urban areas had their infrastructure established in the 1950/60's with relatively small cross sectional sized cables for the demand of the time. Modern appliances (washing machines, dishwashers, fridges, freezers and air conditioning) have raised the typical domestic demand. This factor, coupled with the improvements of alternative supply arrangements for fault or planned outages, has increased the need for greater capacity circuits.

As previously mentioned, our strategy is to run our network more efficiently whilst maintaining a broadly constant level of risk.

Load transfers between sites, particularly at 11kV for pre and post fault conditions are often an economical method of providing reinforcement from existing capacity within the network. In addition to that they are much more readily deployable compared to traditional reinforcement. For this reason transfers are always considered when reviewing primary substation reinforcement as an option.

Unfortunately, transfers are only possible if there is spare capacity in the site's proximity and once used cannot be called upon in case of emergency. In these cases traditional reinforcement is the only solution in order to maintain the level of risk broadly constant.

ED1 forecast

Our ED1 forecast is £79.0M for HV reinforcement and load transfers, which is an increase of £25.7M when compared to our DPCR5 expenditure on an 8-year equivalent basis.

Table 23 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Table and Line (s)
1.34	53,275	79,012	CV101 7-8 CV101 10 CV101 16 CV101 31-32 CV101 51

Table 23 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

HV Reinforcement is expected to increase significantly as part of the development of new 132/11kV substations that are being introduced into the network. These involve major HV works to rationalise the load, simplifying the network to feed load from the closest substations.

The variation in spend is largely driven by impacts of the Central London strategy and the changing the architecture of the HV network and the introduction of new main substations to the network.

Central London Strategy

We have embarked on a comprehensive trial programme of work under the Central London strategy to change the architecture of the HV/LV network by introducing unit protection on five HV feeder groups. In addition, on the remaining LV interconnected feeder groups, we will be installing additional remote control. For those customer's on 'parasitic' load tripping devices we are adding additional remote control operation to our network that will enable us to more quickly restore supplies to those customers by allowing the LV circuit breakers and the tripping devices to be reset remotely.

The full programme of work to apply unit protection is forecast at £24M and will convert five feeder groups as part of controlled roll out over the ED1 period. This approach will ensure there is no loss of supply for an HV cable fault and allows new loads/customers to be connected to these networks without a major redesign of the feeder group. The new architecture makes assessing the impact of load growth on the network simpler. This allows us to provide a better, more responsive service to our connection customers, without resorting to load tripping units and reduces LV fault level on these networks. The new architecture is less prone to a high profile cascade shut down event, reducing the risk of widespread loss of supply and allows us to continue to maintain P2/6 compliant for every feeder group.

We are piloting the approach around Leicester Square, where we are converting a feeder group to unit protection. This group has been selected as it is currently considered to be at a high risk of a cascade shut down event for an HV fault. This was based on comprehensive due diligence exercise across over 60 different LV interconnected feeder groups in 2000 and refreshed in 2013.

While we run the trial, we will continue to reinforce, radialise and automate our network, worst performing feeder groups such as:

- Carnaby Street: Reconfigure N Groups
- Carnaby Street: Reconfigure NE Group;
- Old Brompton Rd South Group radialisation and automation
- Whiston Rd North Group Reinforcement

As the period progresses we will reinforce other feeder groups as they are identified into our plans – we have made budget provisions for this work. .

New Main Substations

Adding new substations allows the transfer of load from heavily loaded substations to new main London substations, which in turn result in opportunities to improve the HV network, including:

- Rationalise the HV network fed from a Main Substation (MSS), to feed the area that is around that MSS as opposed to several km away – reducing losses, and risk of faults (due to the number of joints and risk of third party damage on long cables) and simplifying network operation.
- Make more effective use of the existing HV network by releasing switches and HV circuits for reuse – creating flexibility for accommodating further organic load growth and new connections.

We have identified 8 sites with schemes totalling £7.0M that rationalise the network by transferring load from substation at or over firm capacity to the substations that have or will have spare capacity, including:

- Back Hill 11kV: South group transfer to Fisher Street
- Glaucus St and Simpsons Rd permanent 11kV transfers to Wellclose Sq
- City of London: 11kV load transfers Devonshire Sq/Hearn St/Osborn St permanent transfers
- Eglinton: 11kV network reconfiguration
- Permanent transfer of the City Road B North Group to Plumtree court new switchboard
- Permanent transfer of Beech St B SE group to Plumtree Court new switchboard.
- 11kV Load transfers to Calshot St MSS
- Bulwer Street: 11kV load transfers to White City

We are upgrading feeder groups from 6.6kV to 11kV where main substations are converted from 6.6kV to 11kV. The known schemes (circa £9M having already been spent in DPCR5) include:

- Victoria Gardens
- Moscow Road
- Imperial College
- Amberley Road
- Islington

Further expenditure is required as a large number (of the order of 60) of feeder groups are at capacity and will need to be split or have new feeders added.

In addition to the known schemes we are making further provision for work of this nature in our plans over the eight year period. The provision is circa £3.5M per annum for work of this nature that is currently unknown but we expect to incur. Over the first three years of DPCR5 period we have spent on average around £4M per annum. We have based our forecast on the historical spend for setting the budget provision going forward.

Table 24 below illustrates the additional risks and opportunities that could materially affect the forecast.

	Risks
	An upturn in economic activity could increase load.
	Further migration of night time load.
	Air Conditioning penetration increasing summer peak demand.
	Small embedded generators ability to withstand disturbances on the distribution system.
	Additional works undertaken to address land owner issues.
	Visibility of embedded generation at HV and LV
	Impact of embedded generation to the demand profile at a substation level
	Opportunities
	Removal of high HI plant and cables
	Load Transfers utilises existing Network capacity avoiding high cost reinforcement.
	Improve network functionality.
	Increase interconnection at 11kV between primary substations

improves network resilience;

Table 24: Risks and Opportunities potentially affecting the forecast

3.4.6 LV Reinforcement Schemes

Investment drivers

While it is possible to observe 11kV feeder loads in real-time, no mechanism exists for the LV system, and investment is largely reactive in response to customer complaints or loss of supply.

The forecasted ED1 expenditure allows for:

- Reinforcement work to restore statutory voltage where limits have been exceeded because of increased load;
- Reinforcement work to deal with cases where statutory limits have not been exceeded, but the customer is experiencing excessive flicker or other power quality issues.

In addition to that our plan takes into account the need to reinforce the low voltage network due to growth in domestic generation (e.g. PV, micro Combined Heat & Power, etc.) and the uptake of low carbon technologies (Electric Vehicles and Heat Pumps).

Ultimately, the roll out of smart metering will provide UK Power Networks with greater information on voltage levels at customer level. This is expected to uncover situations where intervention is required regardless of whether a complaint has been made or not.

In order to construct a robust forecast that takes into account all the above mentioned factors, we have developed an LV reinforcement element within our Imperial College LRE model. Please refer to Appendix Section 4.7 for more details.

ED1 forecast

Our ED1 forecast is £28.5M for LV reinforcement. This is £19.7M higher than our current forecast spend in DPCR5 (on an 8-year equivalent basis).

Table 25 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP line	DPCR5 £k (8 year equivalent	ED1 £k	RIGs Code Table and Line (s)
1.39	8,816	28,500	CV101 6-7 CV101 29-30

Table 25 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

In addition to the NAMP projects shown above, there are also reinforcement projects relating to Connections activities in the CV101 table.

We are forecasting LV reinforcement costs to nearly double as a result of data on LV phase unbalance and voltage issues becoming more readily available due to smart meters. Also the LV reinforcement required to accommodate the additional distributed generation will add to this increase.

Reinforcements are typically for voltage or overload problems and historically been reactive due to the lack of visibility of loading and voltage measurement on the network. Over DPCR5 we have seen a small number of problems in maintaining statutory voltage that have led to LV reinforcement e.g. due to load growth and new connections (three in 2013, none in 2012, two in 2011 and one in 2010), this small number of schemes was allocated to circuit reinforcement schemes so do not appear as voltage regulation schemes in the RIGs table. Typically this work is reactive based on issues raised from the operations and network control activities. These are raise through our System Redesign Request process or as part of network analysis for a new point of connection. The chart below shows (a short-term trend) of rising numbers of voltage related visits to premises. As we better analyse and understand the issues and trends behind this short-term trend we will take action to seek to manage the root cause – this may lead to increased reinforcement or other action to ensure we deliver our statutory obligations.

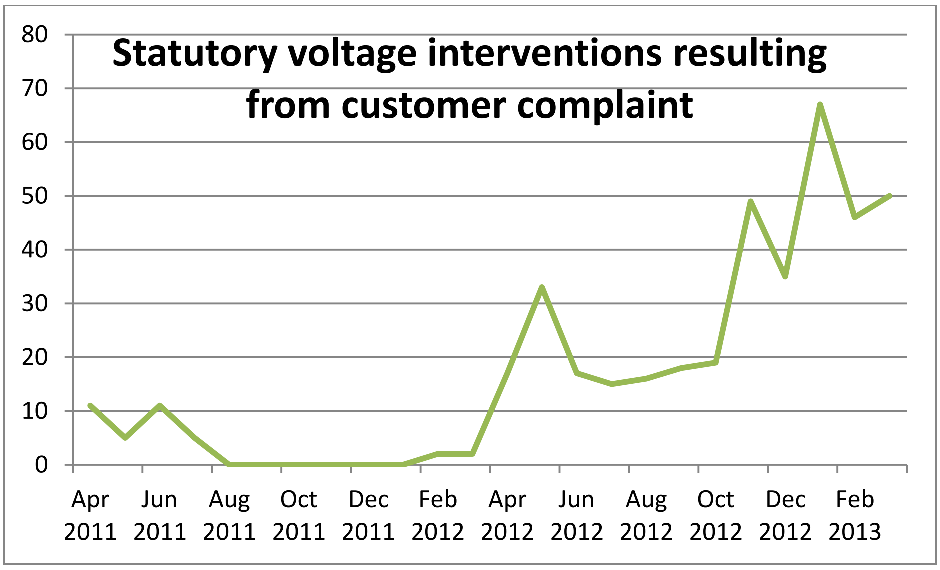

Figure 8: Trend of Customer Complaints relating to statutory voltage

We proactively review feeder groups considered to be poorly performing, in key outputs, e.g. Customer Minutes Lost, and undertake reviews of our network performance to evaluate the potential impact of major faults. We are anticipating visibility of the loading and voltage on the network improving, both through our own systems and smart meter information. As a result we expect this to lead to increased activity in reinforcements on these assets.

In addition to this normal baseload of reinforcements we are expecting further growth in domestic generation, e.g. PV, micro Combined Heat & Power (CHP) that creates difficulties on the LV network. We are expecting the uptake of low carbon technologies (Electric Vehicles and Heat Pumps) to create a rising trend in the need for LV reinforcement. We are working on increasing the visibility of our LV network through innovation projects that will allow more accurate understanding of these issues.

Where overloading is occurring investment is typically triggered where we see repeat fuse operations that suggest overloaded circuits or Secondary transformers. Our Operation teams assess whether the repeat faults are due to load issues or a fault. Where the repeat fuse operations are due to load issues, they highlight these to the planning department for reinforcement to be designed. We are seeing a rising trend in overload issues being raised for resolution via investment in the network.

As well as the observed trends and historical spend, our new modelling tool - LRE model - provides new information on the potential volume of work that may be expected based on the Core Scenario load growth. For the LPN network we have scaled back the modelled output, which is in contrast to our other networks, where we have added into the modelled output spend of the non-modelled elements. Comparing the model to recent history of expenditure suggests that the near-term years are not so representative of the needs on the network. Limitations in modelling remain in accurately representing the interconnected and automated nature of the LPN network.

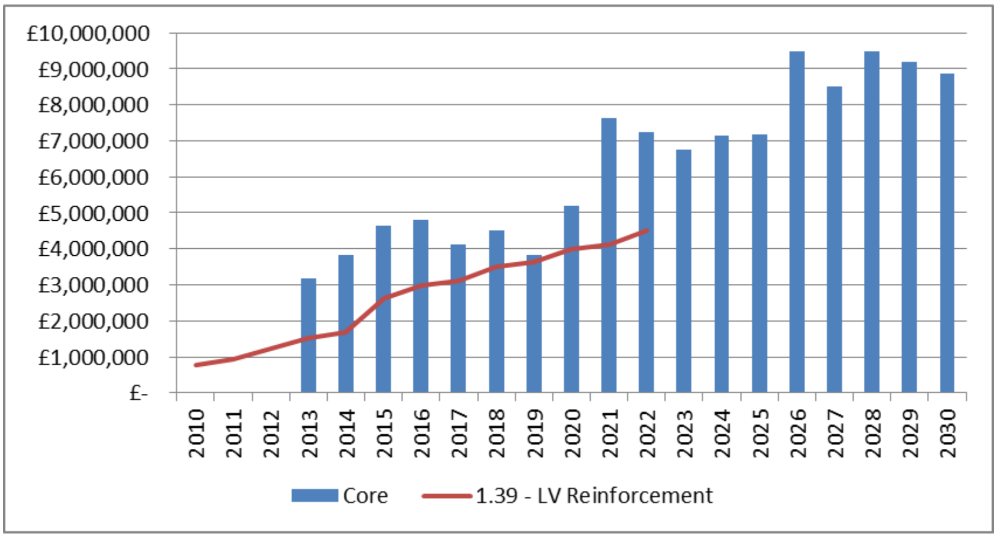

Figure 9: Modelled output and forecast expenditure

Our expenditure forecast assumes a rising rate of expenditure over the period to cater for general load growth in ED1 and the limited expected deployment of EV and heat pump penetration. The profile anticipates a growing need for LV reinforcement into ED2 reaching a level at the end of the ED1 periods that reflects the longer-term growth in investment in the modelled view of the impact on the LV network. We recognise that there remains uncertainty around the uptake in low carbon technologies and will continue to review the requirement for reinforcing our LV network as uptake trends become more obvious.

Table 26 below illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in economic activity could increase load.
Higher EV penetration
Smart Metering Identifies more reinforcement
Higher heat pump penetration

	Higher photovoltaic voltage profile issues
	Opportunities
	Smart Metering Identifies areas suitable for load transfer and/or exploiting existing load diversity
	Photovoltaics offsetting demand
	DSR

Table 26: Risks and Opportunities potentially affecting the forecast

3.5 High Value Projects

This section considers the LPN's high value projects whose forecasted expenditure during ED1 is greater than £25m.

There are two projects belonging to this category.

GWPID	Project ID	Description	ED1 £k
1.33 1.37	6105 8343	West End New 66/11kV Substation - (3x33.3MVA) Construct Lodge Rd to West End Cable Tunnel	37,047
1.35	5815	VNEB New 132/11kV Substation - (2x66.6MVA)	25,815

Table 27 (Source Table J less indirects from 19th of February 2014 NAMP Baseline)

Full details of these schemes can be found in the High Value project - Gate A scheme paper and the appropriate regional development plan.

3.6 Summary of Major Variances: DPCR5 Allowance vs. Actual

Our business plan for the DPCR5 period included a range of reinforcement schemes to accommodate the forecast growth over that period. In many cases the actual schemes that have been carried out have been somewhat different to those anticipated. We have adapted our plan in response to the economic conditions that are showing a sustained period of relatively low economic growth.

Our forecast shows we will over deliver our LI outputs commitments that we made to our customers for the DPCR5 period.

When we set out in our plans for 2010 to 2015 we identified a portfolio of sites and schemes for general reinforcement. In most cases we have undertaken work (albeit sometimes with a modified scope for the vast majority of these sites and schemes while others have been deferred. Only a small number of schemes have been deferred beyond the end of the period the most significant examples being Eltham Grid (£1.7M) and the largest deferral of Carnaby Street £12.5M, due to lower than forecast demand.

We have also seen delays in major tunnelling works projects due to planning consent issues. The delay to the New Cross to Wellclose Square section of the tunnel has deferred spend of around £23.5M. Consents have been delayed due to the interaction of our works with the Thames Tideway development seeking similar land in the Southwark area. The project will connect supplies to the Central Business Districts around the new Osborn Street 132/11kV substation and Finsbury Market. As a result of this delay, expenditure on the cables has also been reduced by approximately £14.8M. We have also seen delays in the development of the new Islington GSP £4.7M that has led to lower spend.

These reductions have been offset by other developments on the network. We have seen large customer led developments in and around the Battersea and White City and have taken steps to address the capacity and resilience concerns of our stakeholders and customers in the Central Business Districts and West End. We are forecasting significant spend in these areas at the end of the DPCR5 period to initiate the development of new and redevelopment of existing substations.

The list below shows major schemes where we are investing greater £5M of additional spend in projects compared to our plan of work in the period 2010 to 2015 including:

- Moreton St: Install 2x66MVA 132/11kV transformers
- Osborn St: Establish new Osborn Street B 132/11kV Substation
- VNEB: Establish new 2x66MVA 132/11kV substation
- White City: Establish new 132/11kV main substation
- West End new 66/11kV substation

The list below shows major schemes where we are investing more than £5M less in projects compared to our plan of work in the period 2010 to 2015 including:

- Finsbury Market-New Cross Tunnel: Install 3x132kV circuits (cables associated with tunnel below) - consent delay/rerouting
- Construct Wellclose Square to Newcross Cable Tunnel - consent delay/rerouting
- Carnaby Street: Reinforcement Phase 2 – deferred pending review of forecast demand growth

Overall for our London network we will out-deliver our LI outputs for load while delivering a saving against our capital expenditure allowance for DPCR5 of approximately 27 per cent or £68M.

3.7 Consents and Deliverability

UK Power Networks has experienced challenges in obtaining routes and sites in DPCR5 and have identified a need to change procedures in order to speed up the consents process. The following indicates areas under consideration:

- Early Access; Obtain a standard wayleave consent ahead of legal completion of an agreed Deed of Grant (DoG) allowing works to start prior to completion of the legal document. There is a risk associated with this that assets are not secured until the agreement has been completed.

- Apply commercial payments instead of discounted land / property values to encourage settlement. This could see increasing landowner / agent expectations resulting in escalating payments and an increase in project costs. This is likely to be an issue in the UKPN footprint.

- Commence the use of Statutory Powers alongside negotiations; this is being factored in to the process as part of Business Transformation that UKPN has instigated to update its procedures. The use of Statutory Powers could have a negative impact of customer image which could affect the OFGEM broad measure table.

  Use of new technologies and systems. The business is currently updating its IT and business systems which will include links to the Land Registry. The system enables the user to identify the numbers of landowners and their correct contact details which in turn will help to reduce the amount of time taken to contact landowners when works require 3rd party consents. In addition this function will give operational teams accurate details of landowners for access for works (routine maintenance / faults) which in turn will ensure landowners are contacted at the earliest opportunity as part of the company's commitment to improve customer service.

  Electronic Documents an additional requirement is the scanning of all the companies' paper consents and legal documents. This will include a data capture exercise to build a property database. On completion this will be visible to all parts of the business so that they can 'self-serve' without the need to request copy documents. This will benefit designers, operations, faults & planning.

- Consent ahead of need; this would require consenting and some payments before the final scheme has been agreed.

- Continue the dialogue with DECC to update Legislation to make it "fit for purpose" DECC has instigated amendments to some of the legislation recently however there are still further areas which the legislation still could be amended.

- Incentivise grantors consideration could be given to payment of a 'signing up' fee for completion of wayleaves and part payment of consideration for deeds.

- Lift and shift clauses where the burden can be shared 50/50 with the land owner or where it is still cost effective to move the equipment at no charge if development permission of the land is obtained and a new route is provided

The deliverability of the ED1 plan is covered in Annex 15 'Network Plan Deliverability'

4.0 Appendices

4.1 Description of UK Power Networks' LPN Network

London Power Networks (LPN) supplies over 2.2 million customers within an area of only 665 km^2. It is almost entirely urban and serves the most densely populated region in the country. Almost the entire network is underground, helping to give London the most reliable electricity distribution system in the UK. The network comprises 30,000km of underground cable, 17,300 substations containing 15,400 transformers and a peak demand of 5201MW for 2012/13.

The distribution network serving central London differs from most other GB electricity networks in the following ways:

- High levels of interconnected (meshed) network at low voltage
- An almost entirely underground network (which is inherently more reliable, but more expensive to reinforce and maintain)
- Greater reliance on low voltage infrastructure

London also presents unique operating challenges, for example: major point load connections not seen elsewhere in the UK, traffic congestion, access and planning difficulties, and the requirement to manage high profile events. In eighteen months we have seen a Royal Wedding, a Royal Jubilee and the Olympic and Paralympic Games. We must also consider the strategic targets of the London Mayor and other London authorities in areas such as the electrification of heat and transport, and the decentralised production of energy.

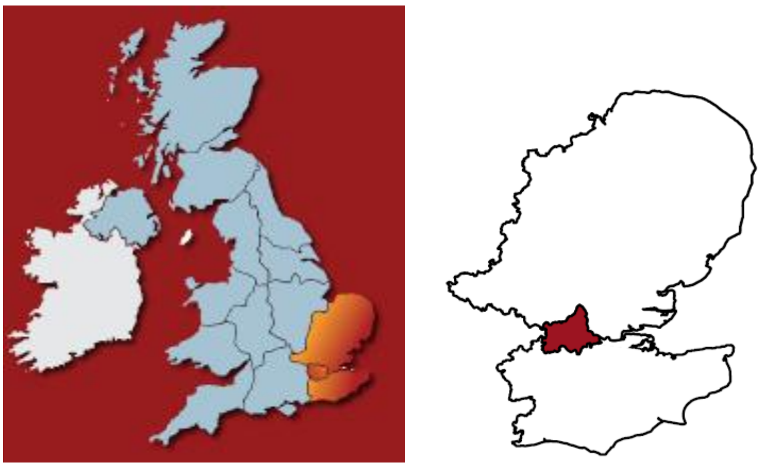

Figure 10: LPN Geographic Area

Electricity is taken from National Grid's 400kV and 275kV networks at 55 Grid Supply Points (GSPs). The National Grid Connection Points within the LPN network are shown in Figure 11. There are 149 primary substations, which operate at 66kV and/or 33kV.

Figure 11: Grid Supply Points

The LPN 132kV network takes bulk power from National Grid at 132kV Grid Supply Points (GSP's). Much of the 132kV cabling is run in tunnels due to the difficulty of accessing roads to install in trenches. The network comprises mainly radial circuits supplying 132/11kV substations with four transformers connected to double 11kV busbar switchboards. A number of these substations are underground.

The total length of EHV cables installed in LPN is 1,484km. The circuits comprise both pressurised and non-pressurised cables. The 66kV and 33kV networks were mostly installed in two principle periods namely 1925-1940 and 1950-1968. 15km of 66kV overhead line was constructed in 1960.

The 20kV, 11kV and 6.6kV networks are all underground with 1km at 20kV and 11,902km of 11kV and 6.6kV cables mostly installed between 1930 and 1970.

There are 16,723 ground mounted substations operating at 20kV, 11kV or 6.6kV. These substations take their supplies from primary substations and transform to 400/230V supplying the LV network or supply directly to customers.

The LV network comprises underground cable only with a total length of 22,462km. PILC construction cables, comprising 92% of the network, was laid up until 2000 and from then onwards polymeric waveform cable was used.

4.2 Our Planning Assumptions

The key external driver for change facing Distribution Network Operators (DNOs) is the requirement for the UK to decarbonise its economy. The UK is committed to reducing carbon emissions by 80% by 2050. In order to achieve this goal a number of medium term goals have been set to be achieved by 2020. These include:

- 30% of our electricity to be generated from renewable sources
- 12% of heat to be generated from renewable sources
- 10% of transport energy to come from renewable sources
- 29% reduction in emissions from homes; and
- 13% reduction in emissions from workplaces

The achievement of these medium term targets, and ultimately the 2050 targets, will have an impact on the construction and operation of the DNO networks and the services that customers require from them. However, there is considerable uncertainty over:

- Exactly what technologies will be deployed to achieve these targets and hence the impact on distribution networks. For example if ground and air source heat pumps are the key technology deployed to meet the renewable heat obligation then the impact on our network could be significant. Conversely, if biomass and biogas are the key technologies then there will be a lower impact on our network ; and
- The impact of new electricity market mechanisms. The impact for distribution networks would be most clearly evidenced in the emergence of new entities providing new services to customers. The most likely outcomes are the growth of Energy Services Companies (ESCos) and Energy Aggregators. The growth of the latter is particularly relevant as it will be a key enabler of the Demand Side Management market.

Another key business driver is the rate of economic growth. Economic growth is a significant driver for increased demand for electricity and hence peak capacity on our network. In addition, a more buoyant economy is likely to mean that:

- Consumers (both domestic and business) may be more willing to invest in reducing their emissions; and
- Government may have more scope to provide incentives to facilitate the take up of emission reduction technology.

However, the converse is likely to be true if the rate of economic growth is slow. However, a slow growth rate may mean that customers are more price sensitive and hence provide an environment which facilitates the growth of a market for Demand Side Management services.

These factors can be aggregated into three main external change drivers. They are:

- Rate of economic activity
- Impact of the deployment of low carbon technology on the distribution network
- Impact of new electricity market mechanisms on the distribution network

4.2.1 Constructing the planning inputs

For each of the macro drivers highlighted above we developed a range of key planning inputs that underpins them. These are shown in Figure 12 below and form the inputs to our demand forecast scenario model:

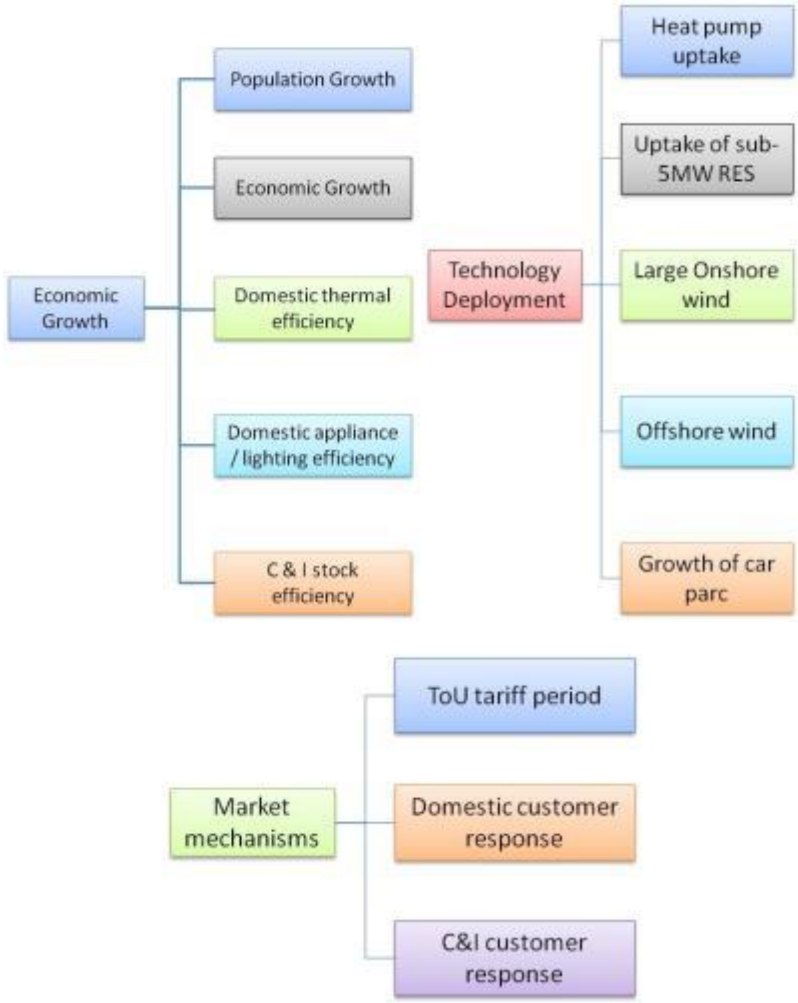

Figure 12: Key Planning Inputs

For each of these assumptions we then derived a high, baseline and low assumption. To develop these assumptions we worked with Element Energy, a specialist energy consultancy, who have undertaken a range of studies in the low carbon technology arena for organisations such DECC, Committee on Climate Change and the Energy Savings Trust. Table 28 sets out the prime data sources for each of our assumptions.

Planning assumption	Data source
• Population Growth	• Department of Communities and Local Government historic and forecast household statistics
• Economic Growth	• ONS data on historic regional Gross Value Added data
• Domestic thermal efficiency	• Heat and Energy Savings strategy targets
• Domestic lighting\appliance efficiency	• DEFRA market transformation scenarios
• Commercial and industrial energy efficiency	• DEFRA market transformation scenarios plus Element Energy analysis on uptake rates
• Heat Pump growth	• Element Energy analysis of likely take up rates based on varying levels of Renewable Heat Incentive
• Small scale renewable generation uptake	• Element Energy analysis of likely takeup rates based on varying levels of Feed in Tariff incentive rates
• Onshore wind	• Current proposals and DECC 2050 pathways analysis
• Offshore wind	• Current proposals and DECC 2050 pathways analysis
• Electric vehicle takeup	• Element Energy analysis of take up rates based on various market conditions
• Growth of car parc	• Based on Department of Transport TEMPRO analysis

Table 28: Primary Data Sources

Element Energy then developed a model which allowed us to model a range of scenarios by combining the assumptions. The scenarios we developed are shown in Table 29. These scenarios were then tested with our stakeholders and the outcome of that engagement resulted in the development of our core planning scenario which was used in our July 2012 Business Plan submission.

	Rate of economic growth	Impact of the deployment of low carbon technology on the distribution network	Impact of new electricity market mechanisms on the distribution network
Green Transition (Scenario 1)	High	High	High
Green Tech Revolution (Scenario 2)	High	High	Low
Green Stimulus (Scenario 4)	Low	High	High
Business as usual (Scenario 5)	High	Low	Low
Economic Concern (Scenario 7)	Low	Low	High

Table 29: Scenarios developed

4.2.2 Developing our core population and economic growth assumptions for the 3 DNO's

The main drivers of demand growth are new household formation and growth in commercial and industrial activity. We believe that utilising long run average data provides the best basis for forecasting future population and economic growth.

Table 30 below sets out the current Government forecasts for new household formation in England split by DNO[1].

DNO	No of households 2013	No of households 2023	Aggregate household growth	Average % year on year growth	% of England total
WPD East Mid	2492	2777	285	1.1%	12%
WPD West Mid	2204	2392	188	0.9%	8%
WPD SWest	1358	1530	172	1.3%	7%
UKPN EPN	3263	3674	411	1.3%	17%
UKPN LPN	2015	2234	219	1.1%	9%
UKPN SPN	2040	2282	242	1.2%	10%
NPG NEDL	1478	1603	125	0.8%	5%
NPG YEDL	2126	2384	258	1.2%	11%
SP Manweb	1012	1077	65	0.6%	3%
SSE Southern	2766	3066	300	1.1%	12%
ENW	2117	2298	181	0.9%	7%
Total (England)	22871	25317	2446	1.1%	100%

Table 30: Government forecasts for new household formation

Table 30 shows that, at an absolute level, the EPN area has the highest forecast household growth and the growth across our three licence areas accounts for 36% of the total forecast household formation in England, with LPN contributing approximately 9%.

Table 31 shows the average percentage yearly increase in actual household formation over the period 1991 to 2008. This demonstrates that historically the actual levels of household formation have been below the proposed Government targets. We have assumed that the yearly level of household formation, over the ED1 period, is equal to the historic long run average for each of our licence areas. We believe that this strikes an appropriate balance between recognising that the number of households, and hence electricity demand will grow, recognising the practical issues associated with delivering significant increases in house building in the South East.

Average annual increase in household formation	%
EPN	0.93
LPN	0.95
SPN	0.78

Table 31: Average annual increase in household formation

[1] UK Power Networks analysis of "Table 406: Household projections1 by district England, 1991- 2033" published by the Department of Communities and Local Government

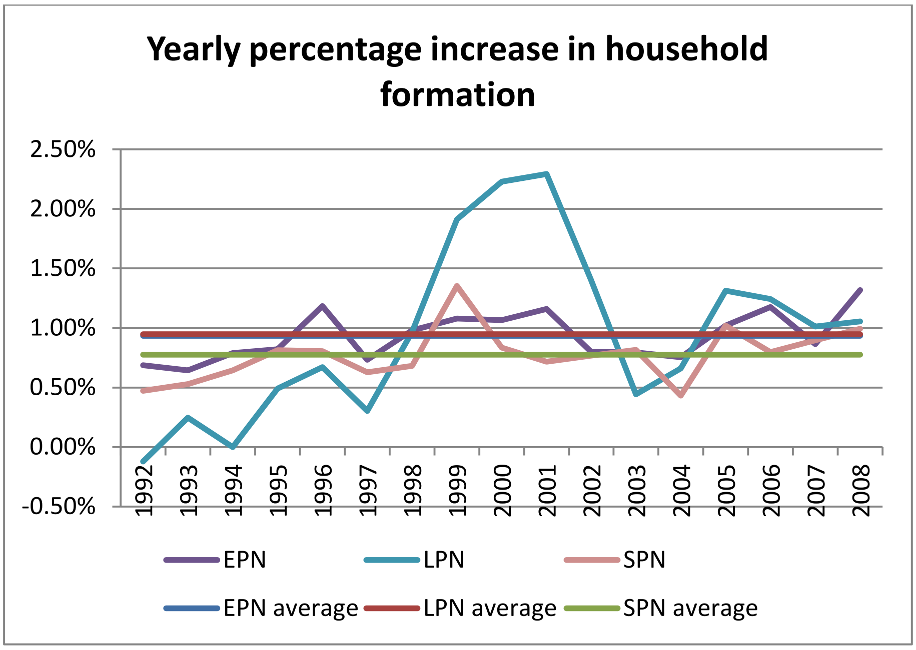

Figure 13: Yearly percentage increase in household formation

Economic growth is a significant factor in increasing demand for electricity and hence the required capacity of our networks. The UK, the wider European and global economies are facing a significant period of continuing uncertainty. The rate of growth in the economy affects our network expenditure levels, as it drives both new network capacity requirements and new connections volumes. Our baseline assumption is that the economy recovers to long run average growth levels from the beginning of ED1. We utilise the regional Gross Value Added (GVA) metric as our key driver as our key economic metric and our forecast is based on the compound annual growth rate (CAGR) over the period 1989 to 2009. Figure 14 details the year on year growth over the period in nominal terms.

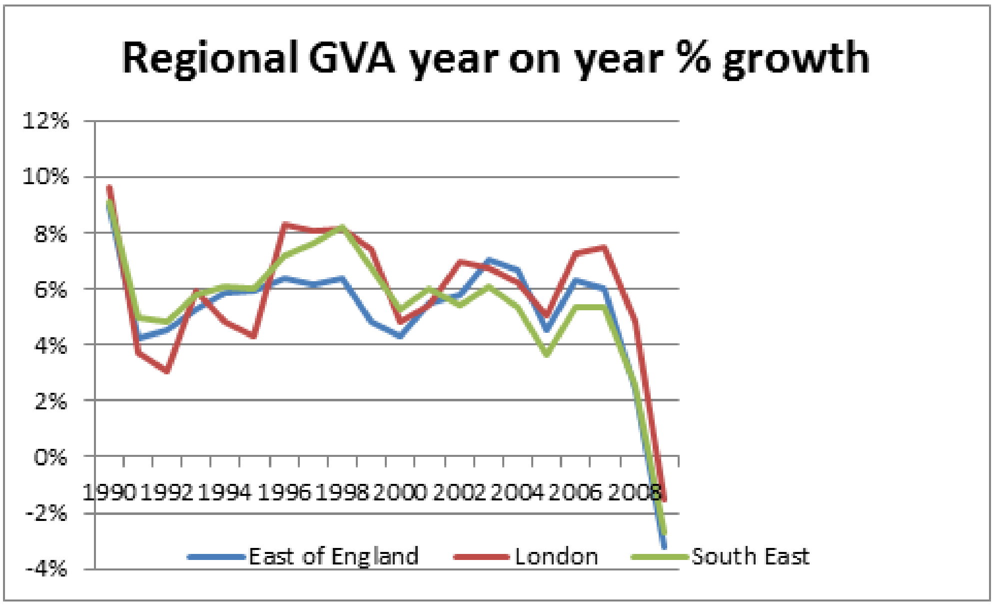

Figure 14: Regional growth over the period
The values used are shown in Table 32 below:

Annual forecast increase in regional GVA (nominal)	%
EPN	5.4%
LPN	6.1%
SPN	4.5%

Table 32: Annual Forecast increase in regional GVA

As can be seen from the table LPN has the highest historical and forecast annual growth in GVA. GVA growth has a direct correlation to electricity demand growth on our networks. The value for the SPN area is lower than the calculated value for the South East regional GVA. The reason for this is that the South East Government Office region covers significant parts of the SSE Southern region network. The area served by SSE contains a number of the high GVA sub regions in the South east area e.g. Bracknell, Oxford whereas the SPN network serves some of the lowest GVA sub region e.g. East Kent. Utilising the South East region CAGR produced a future year on year growth in system demand which was significantly above previous observed levels. The average annual GVA growth has been calibrated to ensure that future growth in maximum demand is in line with previous observed levels.

4.2.3 Impact of transitioning to the low carbon economy

The key uncertainty facing Distribution Network Operators is the impact of transitioning to the low carbon economy. The mass adoption of technologies such as electric vehicles, heat pumps and small scale generation are key to the Government achieving their carbon targets but all of these technologies will impact on the electricity distribution network. In order to understand the impact we have worked with Element Energy who are specialists in the low carbon technology arena and have produced technology take up forecasts for DECC, the Energy Savings Trust and the Committee for Climate Change.

In developing our forecasts we have looked at the particular regional factors that will affect take up rates. For example we have examined the housing stock in each of our regions to understand the likely penetration of heat pumps. The modelling also takes into account the impact of the current incentive mechanisms on customers' willingness to adopt new technologies. It should be noted that our forecast take up rates are not designed to achieve a specific carbon reduction target. Since the publication of our Business Plan in November 2012 we have revised a number of our low carbon technology assumptions to take into account improved modelling, feedback from stakeholders, and changes in the policy environment, including updates from the WS3 transform model.

We have revised our modelling approach particularly in the area of heat pump take up forecasting since our 2012 business plan. The basis of our heat pump forecast was an analysis of the housing stock contained within each of our licence areas. The original 2012 analysis used data from the English House Condition Survey as its base. The house types where then aggregated into ten types to facilitate modelling. Each house type was assigned a heat pump suitability factor. As part of the development of our modelling approach we have used a more detailed analysis of the housing stock based on an Experian dataset. The outcome of this has been to increase the heat pump penetration in EPN but reduce it in both SPN and LPN. We acknowledge that some of our stakeholders felt that our original penetration rates seemed high. In EPN our current assumption would result in approximately 7% of the housing stock would have a heat pump by 2023. This was based on a Renewable Heat Incentive payment of 7.5p per kWh. The latter was the information available when we finalised our 2013 low carbon technology assumptions. However, since then a further consultation has been launched which has proposed upper tariff limits of between 11.5p/kWh and 17.3p/kWh (dependent on the technology type). These are generous incentives and if implemented for a sustained period would be expensive but result in higher take up rates than we have assumed. We therefore believe that our current assumption on incentive rates is a prudent long term view. The impact of heat pumps is lowest on our LPN network.

The feedback we received from our stakeholders was that our assumption on electric vehicles looked optimistic. We agree that the take up of this technology has been slow driven by the significant purchase price differential between electric vehicles and petrol/diesel equivalents and public concerns relating to ease of charging and range anxiety. We have therefore scaled back our assumptions in these areas.

Finally, as part of our analysis of the Smartgrid Forum Workstream 3 model we identified that we had not included any assumptions on the take up of commercial heat pumps. We have used the take up rates assumed in the Smartgrid Forum Workstream 3 model.

The tables below (33-35) compare July 2012 key low carbon technology assumptions with our revised view for this plan.

EPN	July 2012 plan assumption	July 2013 plan assumption
Heat pumps – Domestic (#)	233k	262k
Heat pumps – Non domestic (MW)	Not included	176MW
Electric vehicles (#)	243k	156k
FIT eligible generation (#)	290k	207k
Onshore wind (MW)	724MW	655MW
Offshore wind (MW)	Beyond 2015 assumed to connect to offshore grid	Beyond 2015 assumed to connect to offshore grid

Table 33

LPN	July 2012 plan assumption	July 2013 plan assumption
Heat pumps – Domestic (#)	61k	44k
Heat pumps – Non domestic (MW)	Not included	70MW
Electric vehicles (#)	130k	50k
FIT eligible generation (#)	93k	72k
Onshore wind (MW)	10MW	10MW
Offshore wind (MW)	N/A	N/A

Table 34

SPN	July 2012 plan assumption	July 2013 plan assumption
Heat pumps – Domestic (#)	121k	100k
Heat pumps – Non domestic (MW)	Not included	94MW
Electric vehicles (#)	156k	134k
FIT eligible generation (#)	167k	121k
Onshore wind (MW)	214MW	152MW
Offshore wind (MW)	Beyond 2015 assumed to connect to offshore grid	Beyond 2015 assumed to connect to offshore grid

Table 35

We have also included improvements in both domestic lighting and appliances in our forecasts. DEFRA had developed three views of future improvements in energy efficiency as part of its Market Transformation Programme. They are:

- Reference Scenario - The Reference Scenario is a projection of what is likely to happen to energy consumption of each product if no new policies are implemented. All agreed and formally signed-off policies are included in the Reference Scenario.

- Policy Scenario - The Policy Scenario is a projection of what would happen if a defined set of new product-specific and related cross-cutting policies were implemented. The policies in the Policy Scenario have not yet been agreed or funded but represent those policies which are expected to be introduced as well as likely future revisions to existing policies and, in some cases, novel policy options.

- Best Available Technology Scenario - The Best Available Technology (BAT) Scenario is a hypothetical projection of what would happen if the best available technologies on the (current and future) market were bought or installed from now on.

We believe that energy efficiency will have an impact on future energy requirements. Our modelling in 2012 was based on the Reference Scenario, as it included those initiatives which were funded. We continue to believe that this is the most appropriate solution and hence have applied it in our 2013 forecast.

4.2.4 Analysis of alternate low carbon technology take up rates

The Smartgrid Forum Workstream 3 has developed four take-up scenarios for low carbon technologies at a DNO level. A description of these scenarios is shown in Table 36.

Scenario	Description
Scenario 1 – high abatement in low carbon heat	High level of emissions reductions from uptake of low carbon heat in buildings and industry (8 million installations) with significant emission reductions from transport (60g CO2/km) and significant thermal insulation of buildings (5million solid wall insulations).
Scenario 2 – high abatement in transport	High level of emissions reductions from transport (50g CO2/km), with comparatively lower reductions from low carbon heat (7 million installations) and significant thermal insulation of buildings (5 million solid wall insulations).
Scenario 3 – high electrification of heat and transport	This reflects a future where there is high electrification in heat and transport, with significant uptake of EVs and heat pumps (as in scenario 1 and scenario 2) and lower comparative levels of insulation (2.5 million).
Scenario 4 –	Reflects a future where more than one key technology under-

credit purchase	delivers and carbon credits are purchased. It assumes 1.6 million low carbon heat installations, medium levels of insulation (4.5million) and fuel efficiency of 70g CO2/km.

Table 36: Take up scenarios for low carbon technologies

These forecasts extend to 2050 and with the exception of the low scenario have been designed to achieve the 4th Carbon Budget targets at a national level. The key technologies modelled in these scenarios are:

- Heat pumps
- Photovoltaic generation
- Electric vehicles
- Wind generation

Our position is that our forecasts are based on what we believe the current incentive frameworks will deliver in our licence areas. However, a change in public perception and/or government policy could substantially alter these take up rates.

We therefore have to understand the impact on our investment requirements if these alternative scenarios where to arise. We have used both our own internal long range load forecasting tool and the Smartgrid Forum workstream to develop this analysis.

4.2.5 Constructing our demand forecast

We have developed a demand scenario model in partnership with Element Energy. This allows us to model a range of scenarios, combining differing planning assumptions and applying the result at a regional and more granular level to our network areas. The Core Scenario we have selected was formed following work with our stakeholders and is the outcome of that engagement.

The scenario model builds the peak demand forecast up from bottom up data. The process used to develop the peak demand is described below

- Historic consumption profile data is split into components – domestic, commercial & industrial (C&I)
- Each component is scaled on the basis of the forecast change in consumption
- Diversified profiles are generated for new sectors – EVs, heat pumps and renewables.
- These profiles are then scaled by the consumption forecasts
- Sector profiles are then combined to give an overall after-diversity demand profile for each year.

This is illustrated in the figure 15 below, which includes a view of the maximum peak load over time:

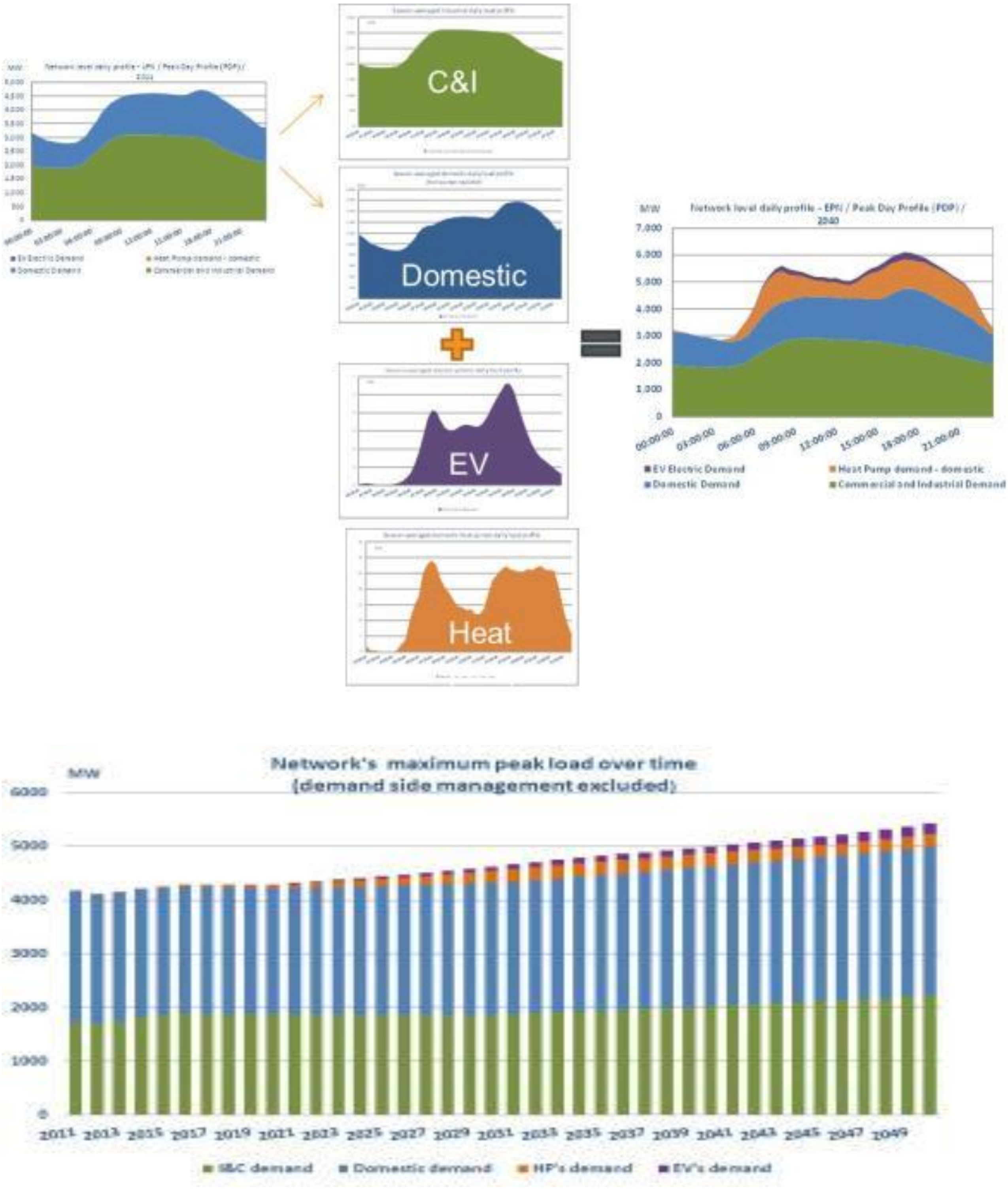

Figure 15: Pictorial view of demand and network peak load evolution over time

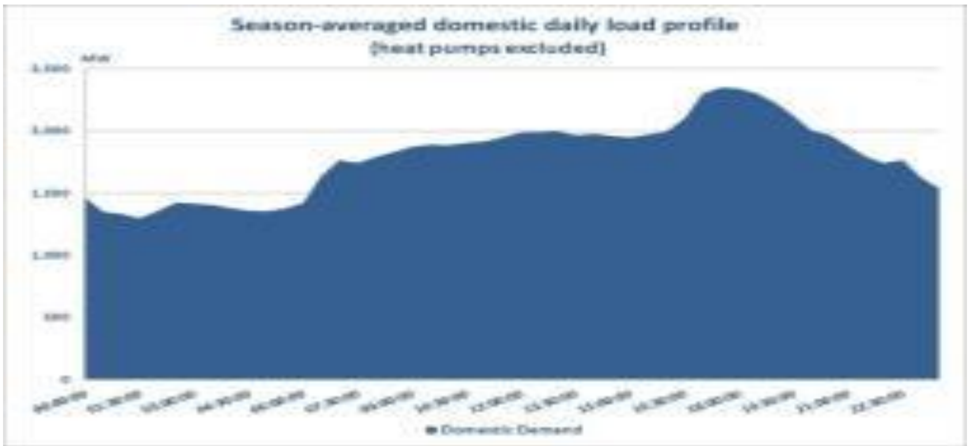

Figure 16: Output of the model

4.2.6 How we use the model in our load forecasting process

The scenario model itself is not used to predict investment requirements. The model does however provide the year on year growth for each of our substations which is then subsequently used in both our top-down load related planning model and our bottom-up planning load estimate process.

The process used is:

- For both domestic and commercial growth the forecasts are disaggregated at a local authority level and this is then spread evenly over the distribution substations in that local authority area
- For the low carbon technologies the take up rates are calculated at a postcode sector level which are then aggregated up to distribution substation level. This is subsequently aggregated up to primary and then grid substation level. The model also applies a clustering factor to the low carbon technologies based on a socio economic analysis of the customers connected to each substation. It currently weights the take up of the technologies towards those customers who are more affluent and are supportive of the low carbon agenda.

4.3 Creating our investment plan – overview

Taking the demand growth forecast, we select appropriate solutions from a full range of intervention options. We take into consideration our overall network objectives, the top-down growth forecast, local insights and the need to maintain flexibility in providing capacity against a backdrop of uncertain load growth. We use two main modelling inputs to support our investment planning, one from our new long-term ICL load related model and the other from the site specific Planning Load Estimate.

The LRE Model provides a system maximum study and therefore models the simultaneous load across the entire system. This provides a view of the network. The model is capable of modelling various start points such as system maximum, system minimum, summer maximum or any other required point in time. This is a less onerous condition than analysing all of the different site maximums at different points in time. The LRE model then applies a given load forecast, or multiple forecasts and provides useful input to consider alternative scenarios.

The LRE Model provides high level information on a greater number of assets than has previously been available by including EHV circuits, HV circuits, secondary distribution sites and the LV circuits in a whole network study. The complete model comprises three smaller models, an EHV model, HV model and LV model and considers thermal, voltage and fault level investment drivers.

The Planning Load Estimates are detailed site studies capturing a multitude of additional and site specific conditions and electrical limitations that cannot always be reflected in a high-level model. This 10 year product is intrinsic to the current planning process having gone through multiple improvements during Distribution Control Price Review Period 5 (DPCR5).

Our Planning Process integrates the modelled outputs and specific local information and analysis to provide a medium to long term view of investments needed for load growth. This information is blended with NLRE requirements to enable an optimised capital programme to be developed.

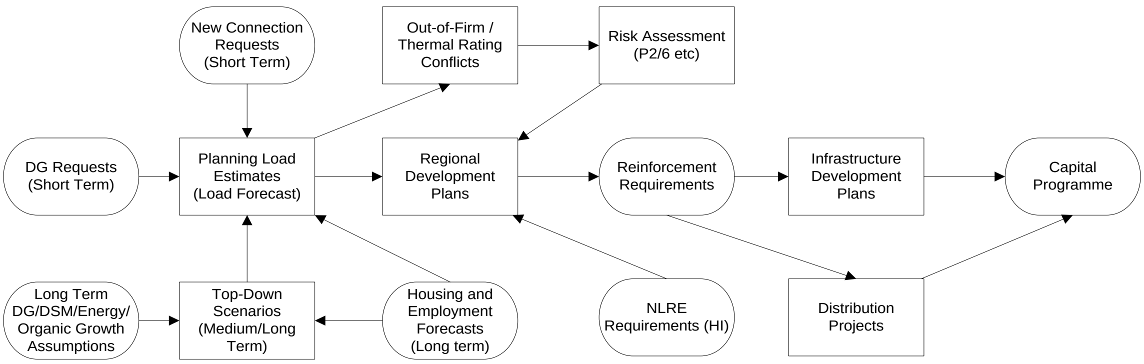

Figure 17: Process Flow Diagram

A key feature of the approach is that the top down modelling and bottom up analysis use common inputs. However the PLE's are applied directly at substation level and consider its maximum demand whereas the LRE model applies the same PLE information holistically at network level and hence addresses the whole system at system maximum demand. The LRE model, because it looks at the whole network, will predict overloaded circuits as well as substations and it uses this output to estimate required reinforcement expenditure. The outputs from the LRE model and the PLE are brought together by the planning engineer into a single regional view of the needs of the network in our Regional Development plans.

The Regional Development Plans present the full view of how individual projects work together to address issues associated with the overall network at all voltages. These take a longer term view (20-30 years) of how the network may develop to ensure that it is fit for purpose considering the wide ranging stakeholder views and requirements. These bring our plans together for an area normally based on the network supplied from the interface with National Grid. These are living documents that incorporate the Planning Load Estimates (PLEs) and known proposed customer connections together with local information and provide an overall view of network development.

Within LPN 12 Regional Development Plans have been established (as shown in Figure 18).

RDP	LPN
1	Willesden
2	Lodge Road
3	St Johns Wood
4	City Road
5	London 33kV Network
6	North London (Islington/Hackney)
7	Brimsdown-Redbridge
8	East London (Westham/Barking)
9	Wimbledon
10	New Cross
11	Beddington-Hurst
12	Deptford Grid

Figure 18: Geographic Areas for RDP's

These programmes provide a well-engineered, holistic and optimised solution to the challenges presented to our networks.

Specifically, the Regional Development Plans:

- Detail all related issues facing the region, including growth, asset renewal requirements, network constraints and transmission interfaces.
- Identify the possible options for addressing the issues faced.
- Recommend a preferred option, based on a cost benefit assessment, with associated rationale.
- Describe the rationale for the rejected options.
- Identify risks, assumptions, dependencies and sensitivities of the preferred option.
- Detail capacity changes and new/removed assets.
- Indicate DG Capacity.
- Identify operational and technical constraints

The RDPs take a view on continuing load growth insofar as they will be designed to take at least the next stage of reinforcement. If there is any doubt about the incremental reinforcement next step a Discounted Cash Flow study will inform the appropriate project selection.

4.3.1 Objectives for network loading and capacity

We develop our load related investment plan to achieve a general objective of delivering the same overall network risk. A measure of this is the profile of Load Index scores across our network – i.e. we seek to maintain the profile at the end of the period is broadly the same as that at the start - based on our best view of forecast demand for our network.

LI Score	% of Firm Capacity	Energy at Risk (MVAh)
LI1	≤70%	-
LI2	>70% & ≤85%	-
LI3	>85% & ≤100%	-
LI4	>100%	<500 MVAh
LI5	>100%	>500 MVAh

Table 37: LI Thresholds used by UK Power Networks within for DPCR5

LI Score	ENWL	NPG	SP	SSE	WPD	UKPN
1	0-90%	0-90%	0-90%	0-79.9%	0-70%	0-70%
2	90-95%	90-99%	90-99.9%	80-89.9%	70-85%	70-85%
3	95-103%	100-115%	100-120%	90-99.9%	85-98%	85-100%
4	95-103% >9hrs or >103% for <9hrs	100-115% for >24 hrs	100-120% for 48-720hrs	>100% for <54hrs	>98% for < 8hrs or less>100%	>100% for <500MVAh
5	>103% for >9hrs	100-115% for >672hrs or >115%	100-120% for >720hrs or >120%	>100% for >54 hrs	>98% for > 8 hrs or 100%+	>100% for >500MVAh

Table 38: Comparison of LI thresholds used by other DNO's for DPCR5

For RIIO-ED1 Ofgem have proposed harmonised definitions for Load Index. The impact of this for UK Power Networks is to generally move sites from LI4 to LI5. Under our previous definition, we were more likely to see investments at sites at either LI4 or LI5. In the future we rarely expect to see sites in the LI4 category and would more often see sites moving rapidly from LI3 to LI5.

LI Banding	Loading percentage	Duration factor
LI1	0-80	n/a
LI2	80-95	n/a
LI3	95-99	n/a
LI4	100	<9 hours
LI5	100	>9 hours

Table 39: Ofgem LI Bandings for ED1

We work to ensure that we are maximising asset utilisation and minimising load-related expenditure. We balance this network design security risk on our networks as necessary to meet our Licence and Distribution Code obligations to ensure that network security risk does not adversely affect the quality of supply received by our customers. Though our "at risk" process we manage substations that may periodically or occasionally be exposed to demands beyond their normal designated Firm Capacity. We investigate the incidence and duration of those occasions when the firm capacity is exceeded to gain a clear indication as to the level of risk to which the substation is exposed.

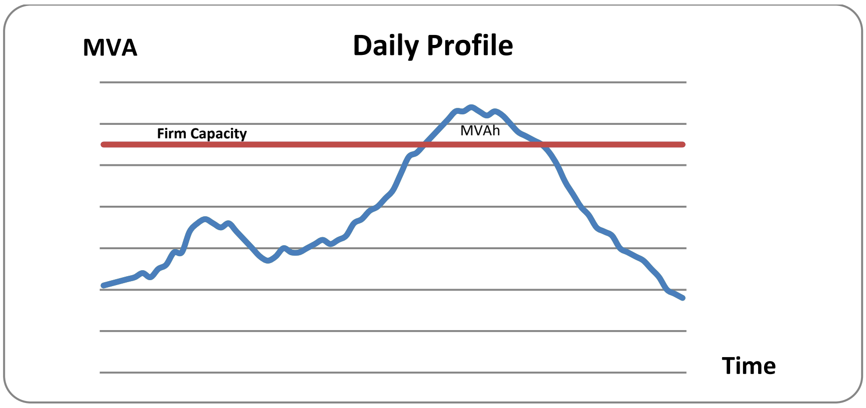

Figure 19: Typical substation load profile showing load at risk

4.3.2 Drivers of intervention

There are a range of drivers that lead to interventions and investments on our network, each is briefly described below.

Thermal Driver

Whilst the thermal limitations of an item of plant, equipment or conductor is the factor that determines its rating, normally it is the current or load that is measured. Whilst it is true that the 33/11kV and higher voltage transformers do have winding temperature hot spot transducers, it is still normally current measurements that trigger a response. The exception to this is the output of the LRE model that will indicate where sections of the network are vulnerable and when this is indicated more detailed load studies will be undertaken. The challenge in using current as the vehicle for assessing the thermal element of an item of plant or equipment is that the result will normally be conservative. Hence a nominal overhead line rating will take a reasonable worst case of ground clearance, wind loading, ice loading and ambient temperature. By applying dynamic line rating methodology to specific circuits a considerable increase in rating may be achievable. Similarly nominal transformer ratings also take a conservative view and by looking at actual daily load curves, actual ambient temperatures and, in the case of a post-fault situation the pre-fault transformer temperature and/or pre-cooling, and applying modelling, it is possible to increase the rating provided that ancillary items such as tap changers and protection are sufficiently rated. Underground cable circuits tend to be treated more conservatively due to the ability to access the circuit. However knowledge of ground resistivity, type and humidity together with proximity of other heat sources such as other circuits may allow for rating uprating.

Voltage Driver

As with the thermal driver the voltage driver is also a function of current. With a nominal voltage and a fixed network the voltage at any point on the network is a function of current and distance. Hence the intervention would differ in some respects depending on the load density or the area. A voltage driver appearing in a town centre is likely to call for a different intervention to a rural situation where static balancers and voltage regulators may be appropriate.

Fault Level Driver

Fault level presents a different challenge and is more intractable than other drivers. Normally it is not desirable to attempt to increase the fault level rating of an item of plant and equipment, such as switchgear, by considering ambient temperature and certainly not for design purposes. At 11kV plant and equipment used is normally designed to the same fault level of 13.1kA and the effect of an increase in fault level can be experienced over a wide area including customer's plant and equipment. Whilst UK POWER NETWORKS is working with fault current limiters (FCLs) their use at EHV is dependent on an economic model.

4.3.3 Intervention options

We identify the need for an intervention through the processes described in the previous sections. We have a range of possible intervention options available to us and depending on what is driving the investment. The table summarises the typical options by investment driver:

Driver	Intervention options
Thermal	Network running arrangements Load transfer Dynamic line ratings Demand-side response Network reinforcement Storage
Voltage	Network running arrangements Network reinforcement Active network management Dynamic line ratings
Fault level	Network reinforcement

	Fault current limiter
Distributed generation	Expansion – new network and existing network reinforcement, flexible/non-firm connection

Table 40: Intervention Options by Investment Driver

In any region of our network we seek to have a mix of interventions that reflect the long-term strategy for that area of the network. That means that the intervention that is considered appropriate depends not only on the absolute level of load or fault level experienced, but also on the overall situation for the region or group. This is because it is the ability of a group of substations or circuits to sustain load normally, and in situations where one (N-1) or two (N-2) elements of our network is out of service that is important to managing overall risk.

We also consider broader delivery issues, including the ability to provide the required reinforcement within a reasonable timeframe, for example, due to limited periods in the year when we can gain access to switch off parts of the network to allow us to add new capacity. This is particularly challenging in urban areas. Here we face particular issues in gaining consents and increasingly high around the year network loadings that prevent easy narrow windows for access. This is a particular challenge within central London and the City but can also be an influence in cities like Cambridge and Norwich. These varied issues and drivers mean that intervention levels and timing become highly site and situation specific.

In deciding on the intervention step we take a holistic view of the existing plant and equipment, the predicted load growth and rate of growth to establish the most appropriate incremental rating step in capacity. This decision is informed by the application of a discounted cash flow analysis which indicates whether more than one increment in capacity is warranted.

Any chosen intervention may serve a number of purposes to provide that area with sufficient network capacity given the expected developments over the longer-term. We capture the decisions in our Regional Development Plans around both traditional and smart interventions.

When applying the options we have regard to our overarching design philosophy and policy contained in our Engineering Design Standards.

The overall design of the network is as documented in three overarching Engineering Design Standards (EDS):

- EDS 08-0145 EHV DESIGN - this standard provides guidance on the design and operation of the 33kV, 66kV and 132kV networks.
  EDS 08-0109 11/6.6KV SECONDARY DISTRIBUTION NETWORK DESIGN - this standard details the guidelines for the design and development of the 11kV and 6.6kV secondary distribution.
- EDS 08-0136 LV NETWORK DESIGN STANDARD - this standard defines UK Power Networks policy with regard to the design of Low Voltage networks.

These three documents refer to other internal and external documents such as ENA P2/6.

Application of these EDSs will indicate what interventions are available and DCF is used to confirm the most appropriate project out of the number of options available.

Each of the intervention options are briefly described below. For the smart options we also indicate where we have applied these solutions in our business plan.

4.4 Traditional Interventions

Network running arrangements

Reconfiguration of the network to route power flows differently. This seeks to lower the utilisation of the overloading asset in question, redistributing the loads to different circuits and assets.

Load Transfer

Building new inter-connection between two sites to allow the load on one site to be supplied from the other site. This can avoid adding new transformer capacity by using existing spare capacity in the region.

Network reinforcement

Creating transformer capacity at a site by adding an additional asset or new or replacing an existing asset for one with higher capacity. Or it could be to create additional circuit capacity by replacing the asset with one of a higher capacity or building a new circuit.

4.5 Smart Interventions

UK Power Networks applies proven innovation to its day to day activities. Developments to off-set reinforcement tend to be applied in two areas. The first is designed to influence network loading and the second is associated with enhancing existing plant and equipment ratings or controlling fault levels and harmonics.

As a consequence the following interventions are considered and applied where they provide the most economic and effective solution:

- Demand Side Response (DSR)
- Energy Storage (batteries)
- Fault Current Limiters (FCL)
- Dynamic Overhead Line Ratings
- Quadrature Boosters

UK Power Networks is always looking for new methods of carrying out its obligations and we have an Innovation Strategy that guides our research and development, working with third party organisations and institutions to bring new ideas to benefit our customers.

Demand Side Response

Demand Side Response (DSR) is essentially a contracted ancillary service which provides demand reduction in response to a dispatch signal. DSR will become increasingly attractive as a residual balancing tool to National Grid, acting as National Electricity System Operator (NETSO) for the main interconnected transmission system and the interconnectors, and to DNOs as a means of minimising the need for network reinforcement to maintain levels of supply security specified by ER P2/6.

Decentralised generation ancillary service opportunities might exist with merchant generators (for example small-to-medium biomass generators and waste-to-heat plants) of for with industrial and commercial business operating CHP / CCHP plant. CHP plant associated with thermal storage or heat networks is likely to be far more flexible and hence more capable of providing a viable ancillary service.

Networks which might benefit from bilateral DSR contracts could include those which at one extreme are at risk due to relatively high (but short duration) demand peaks above firm capacity; or at the other extreme are at risk due to moderate peaks above firm capacity but for sustained periods.

The table below shows the DSR interventions proposed for ED1.

Substation	NAMP Reference	MVA	Start Year	ED1 DSR payments (£k)	Years deferred	Reason
Whiston Road	1.35.05.8554	5.0	2021	150	n/a	Mitigating the impact during the replanting of the station to create the new substation at Hoxton by reducing loading e.g. to widen outage windows
Moscow Road	1.35.05.8556	5.0	2015	150	n/a	Mitigating impact during replanting to increase capacity at the site by reducing loading e.g. to widen outage windows
Wimbledon Grid	1.35.05.8557	5.0	2015	300	n/a	Mitigation of impact during replanting of the Wimbledon substation by reducing loading
Wandsworth Grid	1.35.05.8558	5.0	2015	225	n/a	Mitigation of impact during the switchgear reinforcement of the Wandsworth substation by reducing loading
Eltham Grid	1.35.05.8559	5.0	2013	150	n/a	Mitigation of the risk of higher load growth while new 132/11kV Eglinton is built by 2017
Hyde Park A	1.35.05.8560	5.0	2013	300	n/a	Mitigates the risk of load growth while West End is built in 2019
St Pancras A and B	1.35.05.2576	5.0	2013	150	n/a	Mitigates the risk of load growth while Islington is built and the St Pancras substation

						is upgraded to 132kV
South Bank	1.35.05.8562	5.0	2019	300	n/a	Creates flexibility to defer reinforcement into ED2 due to risk of higher growth from connection activity and a range of developments in the local area, e.g. at Waterloo

Table 41:Sites where DSR is proposed.

Battery Storage Interventions

Selectively deploying storage technologies to improve the effective load factor of distribution connected intermittent wind generation - i.e. flattening peaks and troughs in wind farm output in order to more closely follow demand and/or reducing the need for generator constraint – e.g. when maximum export would result in circuit overloads (perhaps at times of very low local demand).

In 2007, UK Power Networks procured a 200kWh Energy Storage System (ESS) for installation at Hemsby, Norfolk as part of the Autonomous Regional Active Network Management System Research Project, which received support from the Engineering and Physical Sciences Research Council and the Innovation Funding Incentive. Having installed the device in April 2011, UK Power Networks has been running a Low Carbon Network Fund First Tier Project to gain real, practical experience with the device and its capabilities, and to disseminate the findings to the other DNO's. The project brief can be found on Ofgem's web-site, where it is registered as project UKPNT1001 under the project title 'Demonstrating the benefits of short-term discharge energy storage on an 11kV distribution network'. Following on from this trial a full scale storage device is being installed in Leighton Buzzard in Bedforshire.

Currently no sites have been identified in ED1 to use Battery Storage in LPN

Fault Current Limiters

Managing fault level has become an increasing challenge due to a combination of lower source impedance at 132/11kV or 33/11kV substations, and an increased fault in-feed contribution from electric motors and distributed generation, some switchgear is now operating close to its short-time and/or making rating and, in the case of oil circuit breakers, close to breaking ratings.

While 11kV switchgear is currently the most impacted asset group affected by increasing fault level, other assets can also be impacted including (typically):

- 132 of 33kV switchgear (including structures of outdoor switchgear) - for example due to NGET transmission system reinforcements or network reconfigurations – or additional transmission connected generation in-feed
- Medium voltage underground cables – especially smaller cross-section cables with limited short-time (1 second) ratings which might be vulnerable to sheath bursting

due to the mutually repelling mechanical forces acting on the cable cores during short-circuit conditions.

UK Power Networks is participating in an ETI project to trial a pre-saturated (non super-conducting) Fault Current Limiter at SPN's Newhaven 132/11kV Substation. However, a practical constrain to wide-scale adoption is the need to integrate the device within existing 11kV switchboards. In practice this will limit the scope of FCLs as a retrofit solution.

There are no proposed schemes for LPN for fault current limiters.

Dynamic Overhead Line Rating (DLR)

DLR is a means of making spare capacity available on the network by removing seasonal export limits to allow generation to match available network capacity which is a dynamically derived rating taking into account the weather conditions. The DLR will involve the use of weather stations to determine wind speed, ambient temperature, and solar radiation. Together with line current measurements, the conductor temperature can be calculated and the dynamic capacity determined. DLR could be implemented in a number of ways, using locally installed DLR equipment or remotely deployed centralised ANM systems, or using some combination of the two.

There are no proposed schemes for LPN under dynamic line rating (minimal number of overhead lines).

Quadrature Boosters

A Quadrature Booster (QD) consists of two separate three-phase transformers specially connected: a shunt connected unit and a series connected unit. The shunt connected transformer is also called the main or exciting transformer and is fitted with an On-Load Tap Changer (OLTC). The series-connected unit is a coupling transformer. Quadrature Boosters are used to control the flow of real power on three phase electricity transmission networks. Quadrature Boosters are a mature technology at transmission level. Over the years, Quadrature Boosters have been used to control power flows on parallel three phase transmission networks across the world where capacity is constrained by one of the parallel circuits.

A site at Wissington British Sugar Substation has been identified as benefiting from a QD. Network assessment of the circuits out of Wissington has identified the need to trial a Quad Booster to achieve optimal load sharing of the 33 kV circuits 1 and 2 to increase export capacity from Wissington CHP. The export limits are due to partly the uneven load sharing on the outgoing 33 kV circuits and the QD will assist in balancing this sharing. This QB was commissioned in 2013.

4.6 Interventions to support distributed generation

The table below shows the generation connected to our London distribution network.

LPN	MW	Projects
Gas (CCGT)	10	1
On-Shore Wind	1	23
Domestic PV (Solar)	12	3207
Industrial PV (Solar)	31	435
Energy From Waste	90	1
CHP	291	368
Diesel	219	25
Fuel Cell	1	2
Standby Diesel & Other Generation	650	179
Total	**1304**	**4241**

Note
Domestic PV includes G83/1 Generation
Industrial PV includes PV greater than G83/1 (i.e G59/2)
Standby Diesel Generation includes Short Term Parallel

Table 42: MW of approved connected DG 2013 Position (information April 2013)

4.7 LRE Model Top Down Forecasting Methodology

Background

With the advent of the economic downturn, the significant number of PV (Photo Voltaic) installations and the growing likelihood of new low carbon technologies arriving onto the distribution network there is a need to model a variety of scenarios as future predictions of these technologies is highly volatile. UK Power Networks invested in a method of quickly reflecting the impact, at all voltage levels, of these different scenarios. These external factors all have a significant contribution in the reduction of growth of system load. Working with Imperial College London (ICL), who already had extensive knowledge of UK Power Networks', a novel solution in the form of a holistic network modelling tool has been developed. The load-related reinforcement expenditure (LRE) model uses an optimal power flow (OPF) engine that recognises the various sets of nodal information, which has been extracted from UK Power Networks' different power flow models, and uses historic system maximum demand data as measured and collected on each HV circuit. By applying growth, produced by the Element Energy modelling tool, year-on-year, the OPF model is able to flag overloaded assets. Using detailed cost data, it is then possible to generate a cost-profile for that specific load growth scenario. The advantage of this overall approach is that UK Power Networks now possesses the ability to analyse more rapidly the high-level impact of different load growth scenarios.

Long Term Forecasting

In order to model the variable economic scenarios, and likelihood of future technologies being implemented onto the distribution network, the new Element Energy load scenario tool was developed. Coupling this with the LRE Model above enables UK Power Networks to not only forecast multiple scenarios of future load growth out to 2050, but also the reinforcement expenditure impact of each of these scenarios. The combination of the two tools allows UK Power Networks to quickly quantify the different economic scenarios providing a sensitivity around the core (UK Power Networks' expected) load growth scenario.

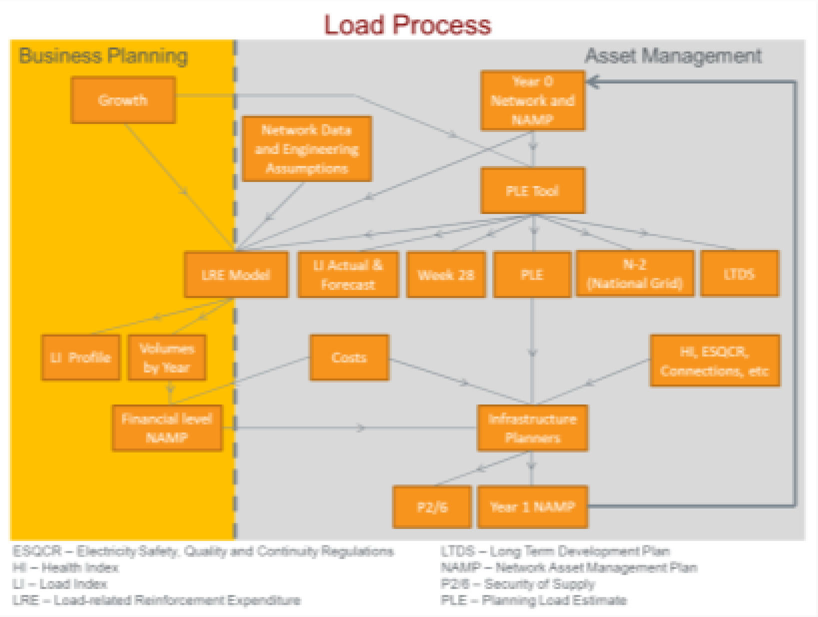

Figure 20: Information Flow

The model is predominantly used to understand the high-level impact of various scenarios whilst sitting alongside other sources of information used in the robust planning process (see figure 20).

System Maximum Study

The LRE model provides UK Power Networks with a system view of the network. The model is capable of modelling various start points such as system maximum, system minimum, summer maximum or any other required point in time. This is a less onerous condition than analysing all of the different site maximums at different points in time. The LRE model then applies a given load forecast, or multiple forecasts, to the network and in this case the UK Power Networks' Core 3.0 forecast and the four DECC scenarios (see Table 43).

Scenario	Economic Growth	Technology Deployment	Market Mechanisms
UKPN Core 3.0	High	Low	Low
High Growth	High	High	High
High Technology	High	High	Low
Low Growth	Low	High	High
Low Case	Low	Low	High

Table 43: Scenario Description

The LRE Model provides high level information on a greater number of assets than has previously been available by including EHV circuits, HV circuits, secondary distribution sites and the LV circuits in a whole network study. The complete model comprises three smaller models, an EHV model, HV model and LV model. These three models are linked by the load input data which feeds in at HV distribution substation level and is aggregated/ disaggregated into the EHV and LV models. Load checks are performed at each node where accurate measured data is available from the network.

Methodology and Data Sources

The LRE model has three distinct sets of information and one set of outputs as detailed in Figure 21.

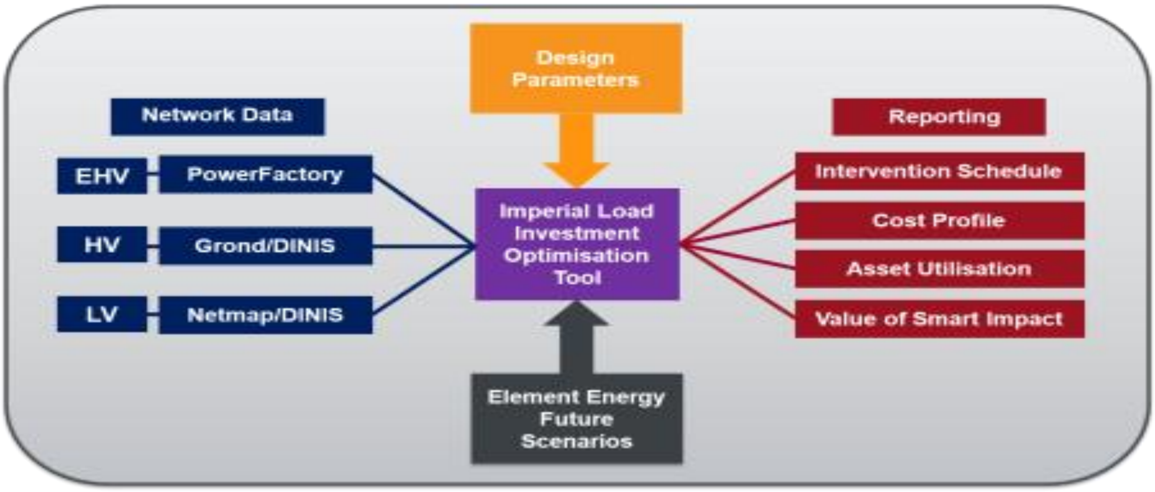

Figure 21: LRE Model Structure

Inputs

The main inputs are:

- Physical network parameters (nodal datasets as extracted from UK Power Networks various meddling and data systems
- Load growth forecast (in this case the output from the Element Energy load scenario model)
- Design parameters (this is the specified start point data and intervention levels)

Physical Network

Imperial College's novel approach allows for various datasets, in a CSV (comma separated values) or similar format, to be interrogated by their bespoke optimal power flow (OPF) modelling techniques. UK Power Networks currently uses DigSilent PowerFactory to model the EHV networks, specifically from the grid supply point through to the 11kV busbar. EPN and SPN use GROND to model the high voltage network (11kV circuits including distribution transformers, switching nodes and point loads). In LPN DINIS is used to model both the HV and low voltage (LV) networks. In order to use a consistent approach the LV networks in DINIS were not used as a dataset for the LV but were used to calibrate the generic LV modelling methodology, which are used to model the LV in EPN and SPN.

The data for the LV circuits is not stored in a power flow model as network data is not available in an appropriate format at that voltage level (except for LPN). A fractal model is used in order to model the LV which is expanded upon in the section below.

The LV fractal models use information extracted from Netmap (GIS) and Ellipse (asset database).

Ratings	
LV Circuits	Use values from Netmap/DINIS
Secondary Distribution Substations (DTX)	Use values from Ellipse/GROND
HV Circuit (11kV/6.6kV)	Ellipse
Primary Substation	PowerFactory
EHV Circuits (33kV/132kV)	PowerFactory
Grid Substations	PowerFactory

Table 44: Sources for Rating Data

Load growth forecast

The growth forecast input comes directly out of the Element Energy load growth scenario model disaggregated at a distribution substation (11kV to 415V) level. The forecast includes:

- Domestic + Commercial & Industrial (C&I) load profiles (MW)
- Heat Pump (HP) profiles (MW)
- Electric vehicle (EV) profiles (MW)
- Annual new domestic connections
- Annual number of HPs (Heat Pumps) in service
- Annual number of EVs in service
  - BEV, PHEV, and RE-EV (battery, plug-in hybrid and range-extended electric vehicle)
- Generation data
  - It will impact various voltage levels

Growth	
Secondary Distribution Substations (DTX) – Start point for model load	DTX load growth as per Element Energy model load growth. Start year is 2012 because this is the year from which the measurements are taken
LV Circuits	Start point is taken from above and applied to the fractal model for LV circuits fed from each distribution substation
HV Circuits (11kV/6.6kV)	Growth supplied by the Element Energy model is aggregated from distribution substations allocated to specific HV circuits. HV customers receive no growth
Primary Substation	Sum of the aggregated growth on HV circuits
EHV Circuits (33kV/132kV)	Sum of the aggregated load on Primary Substations fed from the same EHV circuit
Grid Substations	Sum of the aggregated load on EHV circuits

Table 45: Application of Growth in the LRE Model

The aggregated load growth is reconciled against network nodes where accurate measured data is available from SCADA systems

Design Parameters

Starting Loads	
LV Circuits	Use the results after matching from the secondary distribution substations as described below.
Secondary Distribution Substations (DTX)	a) When a DTX has a half-hourly recording use the DNO Peak Time value. b) When a DTX has no half-hourly recording or a half-hourly value that is below 10% of rating (i.e. likely to be erroneous) but does have an MDI (bi-annually collected maximum reading) then use this value. c) If there is no half-hourly or MDI then use one standard deviation of MDI/rating calculated from the existing half-hourly MDI population and assign values to the missing sites. This applies to both GMT and PMT (ground-mounted and pole-mounted transformer respectively, typically for 11kV to 415V transformation). This standard deviation is calculated separately for sites above and below 500kVA. All of these values need to match the recording measured on the HV circuit source. In order to do this appropriately a factor is applied to increase/decrease the load on the DTX. This is never applied to a half-hourly value. If the factor is above 1 then it is only applied to Estimated values in c). If the factor is below 1 then it is applied to both MDI (Maximum Demand Indication) and Estimate in b) and c).

HV Circuit (11kV/6.6kV)	a) When a circuit has stored half-hourly recordings use the DNO (Distribution Network Operator) Peak Time value b) When the circuit has no half-hourly recording, then it's calculated what this value would be given the difference between the Primary Transformer readings and the circuits with values. Should there be more than one circuit missing a value then split the load in the same proportions to the sum of the DTX ratings on each circuit.
Primary Substation	When a primary has half-hourly recording use the DNO Peak Time value, otherwise calculate.
EHV Circuits (33kV/132kV)	Use half-hourly recordings otherwise calculate.
Grid Substations	Use half-hourly recordings otherwise calculate.

Table 46: Starting Load Parameters

Design parameters are user defined variables that can be re-configured if the need arises. These design parameters include starting loads and intervention levels (Tables 46 and 47). Starting loads dictate the state of the system i.e. whether the network is the setup for a summer maximum, winter maximum, system maximum, summer minimum or any other arrangement such as at UK maximum as specified by National Grid. The starting loads are taken from the SCADA collected half-hourly averaged data, which is stored in PI Historian, for the HV circuits and a number of secondary distribution sites. Using the connectivity model this load is then aggregated all the way up to the Grid Sites. For the remaining secondary sites maximum demand indicators (MDI), collected every second year and stored in Ellipse, are matched alongside the point-in-time data from the circuit and any secondary substation on the circuit that has point-in-time data. If there are any sites without available accurate data, its value if is approximated as explained below.

In line with UK Power Networks' standard reinforcement requirements, based upon engineering best practice, statutory limits and security of supply standards, it is possible for the LRE model user to configure these elements which have a significant impact on the frequency of intervention. Table 47 shows the default value set specified in the current version of the LRE model.

Intervention Levels	
Asset Type	Percentage of Rating/Limit
LV Circuits	100%
Secondary Distribution Substation (EPN/SPN)	130%
Secondary Distribution Substation (LPN radial)	160%
Secondary Distribution Substation (LPN inter)	80%
HV Circuits	75%
HV Switchgear	50%
Primary Transformers (n-1)	130%
EHV Circuits (n-1)	100%
EHV Switchgear	50%
Grid Transformers (n-1)	130%
LV Voltage Limits	-10% to +6%
HV Voltage Limits	+/- 6%
EHV Voltage Limits	+/- 6%
HV and EHV Fault Level	100%

Table 47: Intervention Parameters

Methodology

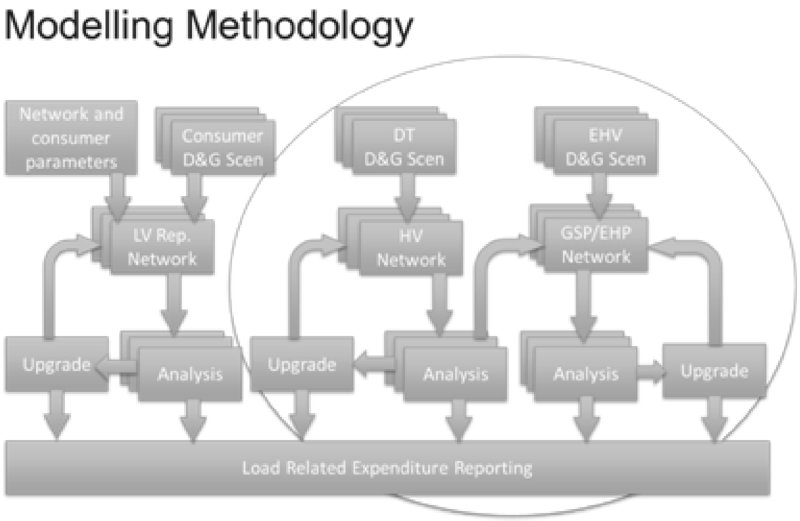

Figure 22 – Modelling Methodology

LV Networks Analysis

From the Domestic + C&I (Commercial & Industrial) Peak Day (PD) Profiles in MW the annual peak growth rates are calculated and applied to all distribution sites. Using heat pumps' (HP) peak day profiles and the annual number of HPs in service the diversified peak of HPs is estimated assuming diversified factor of 0.8. Using electric vehicles (EV) peak day profiles and the annual number of EVs in service the diversified factor of EV will be estimated assuming a peak demand of single charging point of 3.1kW.

For all the annual new domestic connections, 10% of new domestic connections are assumed to be connected to the existing networks (already included in the above growth rates) and 90% of new domestic connections are assumed to be connected to the newly built networks; new network length and the number of distribution transformers is assumed to be proportional to the existing LV network.

This load is then applied to generic models that closely match the electrical node and load density of the actual LV networks. There are approximately 800 generic variants of LV network applied to the approximately 100,000 actual variants of LV network. Electrical node and load density is a function of LV lengths, number of customers, and starting load.

In order to calibrate the Imperial College model it is necessary to populate the model with verifiable business data. This business data is extracted from business as usual systems at regular points in time indefinitely. This data is then stored in a central input sheet. The types of inputs are: site GIS location, power flow modelling nodal data, secondary distribution MDI data, PI Tag data (SCADA half-hourly average), rating data from Ellipse, length data from Netmap, customer numbers per distribution transformers, local authority information and growth data although this list is not exhaustive.

The HV and EHV networks are modelled using Imperial College's bespoke OPF model in order to calculate all the power flows, losses, voltage violations, fault levels and each of the interventions required for each asset class.

This produces a schedule of assets alongside which can be attributed a unit cost. In this way it possible perform asset category costs movement, overall reinforcement cost and likely cost required for specific site projects.

Smart Interventions

Using a set of rules, the LRE model is able to suggest where certain smart interventions may be used. These suggestions must be vetted for viability by the Infrastructure Planning Engineers prior to inclusion in the plan. There are three particular smart interventions that the model focuses on:

- Demand Side Response (DSR)
- Energy Storage
- Fault Current Limiter (FCL)

Demand Side Response

Using the OPF, the utilisation of a primary or grid site is calculated for every year in the defined period. It is possible to use DSR to defer investment or, in some cases, DSR may provide a more permanent solution. The following rules (Figure 23) are applied in the model if the load forecast does not predict any future growth after a site capacity is breeched:

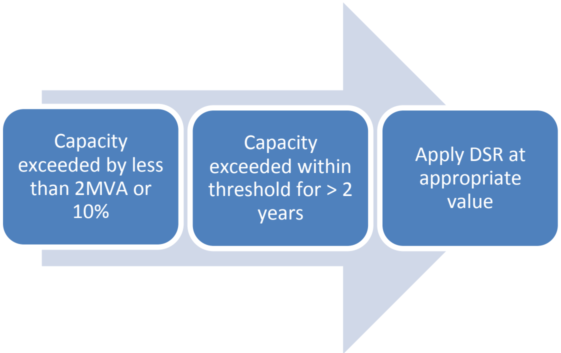

Figure 23: Rules applied in the Model if load forecast does not predict any future growth after a Site capacity is breeched

Energy Storage

Using the OPF, the utilisation of a primary or grid site is calculated for every year in the defined period. It is possible to use storage to defer investment or, in some cases, storage may provide a more permanent solution. The following rules (Figure 24) are applied in the model if the load forecast does not predict any future growth after a site capacity is breeched:

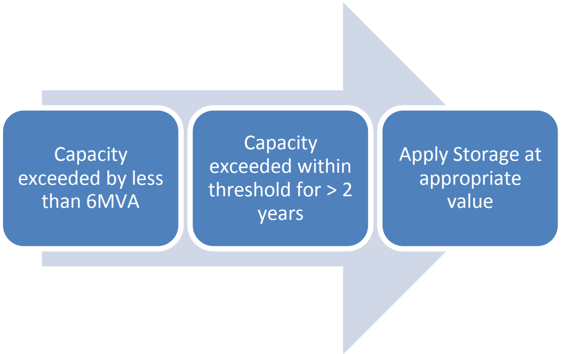

Figure 24: Rules applied in the Model if the load forecast does not predict any future growth after a Site capacity is breeched

Fault Current Limiter

Fault Current limiters are currently being trialled by UK Power Networks and provide a novel solution to an increasing number of fault level constraints caused by growing numbers of distributed generation connections. Using the fault level calculations of the OPF and the growth of synchronous generation, the LRE model can suggest where fault current limiters can be used as an intervention. This is a simplistic calculation based on level of violation and opportunity i.e. exceeding fault level rating of switchgear. This only applies on the EHV model.

Assumptions

The following assumptions have been made in developing this modelling approach:

- Data sources and systems are accurate and reliable enough in order to perform this task.
- The Imperial College model provides a comprehensive schedule listing each transformer and line length that exceeds a specified replacement level. This output schedule needs a degree of processing with regard to asset name mapping the PowerFactory name to the Ellipse name and number. The schedule is then placed in the Model Output Template where the Ellipse number allows the schedule to be compared and rationalised with the non-load model outputs. The Model Output Template is also able to attribute the compatible unit (CU) cost less indirect cost to the scheduled intervention action dependent on the type and size (rating) of the asset.
- The CUs currently being used are generic and not DNO specific.
- The CUs do not include any indirects.
- The CUs represent the cost for replacing a single unit. This is different to the current NAMP (Network Asset Management Plan) format where the total project may include up to 4 transformers to be changed where the model output recommends individual transformer changes. The model output in this case can be interpreted as a required site intervention.

The data produced by the model is used in conjunction with other data sources in the formation of a well justified business plan – it is not intended to populate a business plan automatically.

Model Output

The model interventions are flagged for either Thermal, Voltage or Fault Level constraints. Thermal and fault level constraints are modelled against equipment ratings pre-populated in the model. Voltage constraints are modelled against statutory limits defined in ESQCR (Electricity Supply Quality, Continuity Regulations). Below are some example outputs from the model.

Example Model Outputs

Substation Intervention

- Thermal Constraints (system maximum only, typically exceed by site specific planning load estimates – described below)

Grid	Year	Site ID	Substation type	Rating	Recommended Replacement	Voltage
Bloomfield Place 6.6Kv	2022	31674	GMT	500A	800A	HV
Carnaby Street M.S.S. 22Kv	2022	31387	GMT	800A	1000A	HV
City Road B 11Kv	2017	40041	GMT	500A	800A	HV
Duke St B 11Kv	2017	31427	GMT	750A	800A	HV
Ebury Bridge 11Kv	2020	11861	GMT	800A	1000A	HV
Fulham Palace Rd C 11Kv	2020	10367	GMT	500A	800A	HV
Hackney C 6.6Kv	2029	44281	GMT	500A	800A	HV
Hearn Street 11Kv	2029	41117	GMT	750A	800A	HV
Imperial College 6.6Kv	2032	11358	GMT	750A	800A	HV
Amberley Rd 6.6Kv	2023	T2	Primary	12MVA	18MVA	22kV
Amberley Rd 6.6Kv	2023	T3	Primary	12MVA	18MVA	22kV
Bulwer St 11Kv	2021	T1	Grid	18MVA	30MVA	66kV
Bulwer St 11Kv	2021	T2	Grid	18MVA	30MVA	66kV
Fairlop Rd 11Kv	2030	T3	Primary	18MVA	30MVA	33kV
Fairlop Rd 11Kv	2030	T1	Primary	18MVA	30MVA	33kV

Table 48: Example of LPN Substation Intervention Output Table

Switchgear Interventions

- Thermal Constraints (system maximum only, typically exceed by site specific planning load estimates)
- Fault Level Constraints

Substation	Year	Voltage (kV)	Name	Violation type	Old Rating (A)	New Rating (A)
Axe St 11Kv	2021	11	EDNA004QAS	Continuous	400	630
Barking West 33Kv	2019	33	SGT3A_CB	Continuous	2000	2500
Barking West 33Kv	2031	33	SGT1A_CB	Continuous	1250	2000
Barnes B 6.6.Kv 6.6Kv	2023	11	RDBD005DS3	Continuous	630	800
Carnaby Street M.S.S. 22Kv	2027	11	EDWE001JVL	Continuous	400	630
Churchfields 11Kv	2017	11	EDSO000PSP	Continuous	400	630
Duke St B 11Kv	2031	11	EDWE005ZHR	Continuous	630	800
Ebury Bridge 11Kv	2025	11	EDWE003JXA	Continuous	630	800
Forest Hill 11Kv	2029	11	EDSO003ZKL	Continuous	400	630
Glaucus St 11Kv	2020	11	EDNA005W18	Continuous	630	800
Hyde Park A 11Kv	2030	11	EDWE000LWM	Continuous	400	630
Kingsway 11Kv	2020	11	EDWE000GM9	Continuous	400	630
Lodge Rd B 66Kv	2029	66	SGT4A_CB	Continuous	2500	3150
Merton 11Kv	2032	11	EDSE005R4S	Continuous	630	800
Verney Road 11Kv	2027	11	EDSE005O3V	Continuous	400	630

Table 49: Example of LPN Switchgear Intervention Output Table

Circuit Interventions

- Thermal Constraints
- Voltage Constraints

Grid	Year	Feeder Reference	Voltage (kV)	Length of Underground Cable Replacement (km)		Length of Overhead Line Replacement (km)	
				Thermal	Voltage	Thermal	Voltage
Amberley Rd 6.6Kv	2022	EDWE00633M	11	1.393			
Bulwer St 11Kv	2031	EDNA005W17	11	2.066			
Chislehurst 11Kv	2017	EDNA005VFC	11	0.5935			
Ebury Bridge 11Kv	2019	EDSO003ZKH	11	0.9596			
Edwards Lane 11Kv	2025	EDSE005R4G	11	1.107			
Farjeon Rd 11Kv	2019	0	0	0.6912			
Glaucus St 11Kv	2023	(blank)	11	3.2928			
Islington B 6.6Kv 6.6Kv	2030	EDWE003BSK	11	3.2579			
Lombard Rd B 11Kv 11Kv	2022	(blank)	11	1.4553			
Montford Pl B 11Kv	2027	EDNA000OKN	11	1.1669			
St. Pancras B 11Kv	2023	EDWE001UAL	11	1.0349			
Sydenham Park 33Kv	2027	EDWE005LQY	6.6	0	1		
Townmead Rd B 11Kv 11Kv	2030	EDNA004QB0	11	1.2238			
Victoria Gardens Mss 6.6 6.6Kv	2017	EDWE00631L	11	1.6503			
Waterloo Rd 11Kv	2025	EDSO002S9W	11	2.8953			

Table 50: Example of LPN Circuit Invention Output Table

<u>LRE Model – Next Steps</u>

There are a number of opportunities to develop further analysis and functionality. Outstanding data gaps that, when completed, will improve the accuracy of the model output. Most of the improvements are under UK Power Networks control i.e. improve data quality and structure, but with the knowledge Imperial College has gained from working the data and the constraints Imperial's insight into the fixing UK Power Networks data gaps will be invaluable.

Functionality of the model could be improved by implementing the following methods:

- Develop an algorithm that allows the modeller to artificially set the replacement level to the current delivery volume.
- Articulate different intervention strategies. Have an interface that sits on top of the model that allows the modeller to choose different parameter settings.
- Could the model incorporate profiles and energy at LV and be able to build from this point back to the GSP. Incorporating smart meter data.
- Automatic update from data systems.

4.8 Planning Load Estimate - Bottom Up Forecasting Methodology

The Planning Load Estimate process uses actual load measurements based on half hour measurements (LIMES) derived from most EHV (132 &33kV) and HV (11 & 6.6kV) circuits. These measurements have been accrued over many years and can provide good trend analysis. The load readings feed into the Planning Load Estimates (PLEs). The future load growth applied to the existing load readings and derived from the Element Energy model.

The PLE's are used to inform network modelling so that load flows within the network can be assessed. The output from this modelling is used to assess what circuit reinforcement is required together with consideration of network security and resilience. P2/6, part of the Licence Conditions, provides a minimum level for these considerations. Figure 25 shows the process flow.

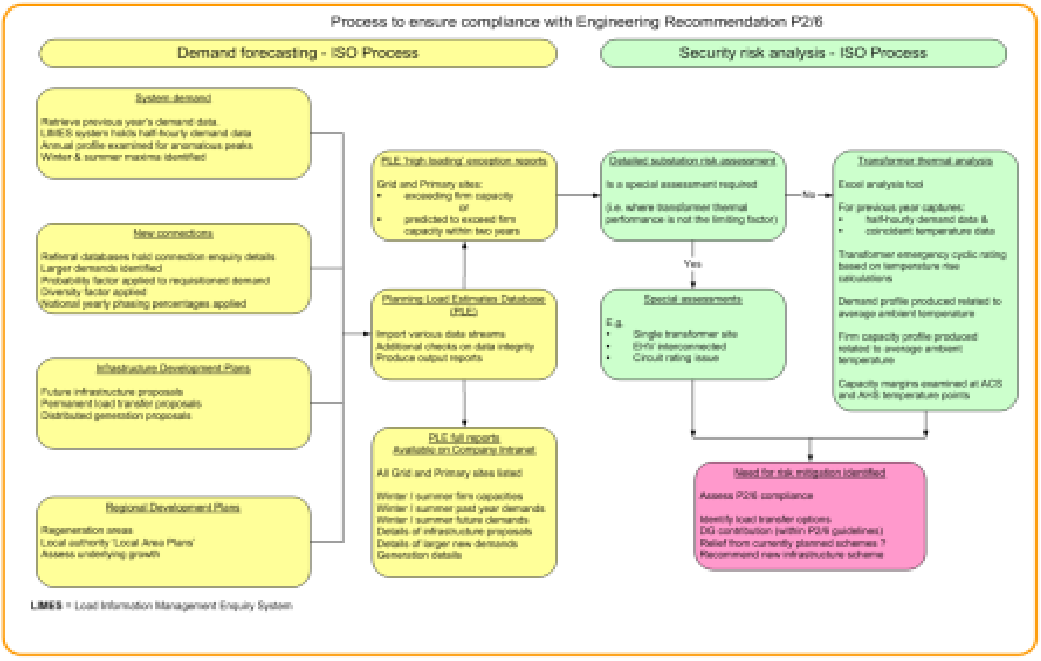

Figure 25: P2/6 Process Flow

Whilst network security and resilience need to be maintained a further level of consideration relating to system utilisation is required. UK Power Networks' three licensed networks have been shown to operate at the highest overall system utilisation levels and this will continue. However, this requires the planning engineer to make a detailed on-going assessment of:

- Capacity and Period at risk
- Annual (seasonal) period at risk
- Consecutive hours at risk at times of minimum plant margin
- Thermal inertia of critical plant (specifically transformers – based on CP1010). Summer loaded sites need careful attention due to lower margin for error and risk of prolonged hot spell
- AHS (as well as ACS) conditions need to be considered for summer loaded sites
- Period at risk if not at the time (in seasonal terms) of peak demand
- Capability to deal with temporary overload conditions
- Ambient temperature and 'previous day' demand cycle
- Available transfer capacity
- Time available for transfer, by automation if necessary, based on calculated time available before WT trip

To sum up the bottom up forecasting methodology starts with the PLE's that give actual load readings. These readings are then used to assess substation performance. They further inform network analysis which also allows overall system assessment of security and resilience. Finally system utilisation is considered. The output of this overall process will be fed into RDP's and inform to NAMP.

We assess risk in detail through the Planning Load Estimation (PLE) process. This seeks to ensure we adequately manage utilisation over the coming years to be compliant with our licence obligations, to calculate our regulatory performance (Load Index) and evaluate which projects should be accelerated, deferred or changed to deliver our commitments to our customers.

The PLE process provides a first pass evaluation of substations it feeds into the assessment of network security risk and P2/6 compliance at Grid and Primary substations as well as the substation load-related risk analysis. Each of these processes is described briefly below. These processes are detailed in EDP 08 107 and EDP 08 108.

Assessment of network security risk and P2/6 compliance at grid and primary substations.

The objective is to ensure that UK Power Networks is maximising asset utilisation and minimising load-related expenditure, while at the same time managing network design security risk on its public networks as necessary to meet its Licence and Distribution Code obligations; and ensuring that security risk does not adversely affect CI and CML targets. The appraisal methodology set out in this document and in the associated 'At Risk' process (EDP 08 108) provides a robust assessment of risk on a site-specific basis and thus permit the effective prioritisation of reinforcement schemes.

Guidelines for substation load-related risk analysis (The ‘At Risk’ Process)

This deals with substations that may periodically or occasionally be exposed to demands beyond their normal designated Firm Capacity. When this happens reference to site maximum demand (MD) without investigating the incidence and duration of those occasions when the firm capacity is exceeded does not give a clear indication as to the level of risk to which the substation is exposed. There may also be other contributory factors, such as temporary changes to system running arrangements that have influenced the recorded MD. By using a transformer thermal analysis tool (TTAT) and a risk evaluation tool (ARET) allows a judgement to be made as to whether a substation needs reinforcement work (and the nature of this work). This continually developing approach has proved successful and ensures that assets are efficiently utilised, promoting optimum and economical timing of load related work programmes

4.9 Governance

Each step of our reinforcement investment process described above is undertaken within strict governance rules and processes. This ensures that the NAMP is:

- Challenged by the relevant decision makers;
- Change controlled;
- Rigorously risk assessed;
- Appropriately documented;
- Properly communicated;
- Effectively implemented.

Specifically, the individual projects are scrutinised at:

- **Design Review**. This consists of fortnightly weekly meetings chaired by a senior manager within the Asset Management Function during which the initial project concept is scrutinised from an engineering perspective. Attendees include representatives from Connections, Capital Programme Delivery, Capital Programme Design and Operational Control.

- **Investment Portfolio Board.** This consists of plans, relevant documentation and meetings where capital expenditures approvals are sought. The Board is chaired at Director (or by a delegated person) and its members include experts from Connections, Capital Program Delivery, Programme Design, Finance and Procurement

Each NAMP investment projects requiring capital expenditures are subject to the “Regulated Project Approval Process” (EDP 08-0801). The framework details the approval authorities, roles, responsibilities and procedures that need to be adhered to when approving capital expenditure for regulated projects.

Project approval occurs at several stages within the overall “Regulated Project Approval Process”: at the Outline Investment Approval stage, at the Investment Approval Stage and at the Project Closure stage.

Figure 26 provides an overview of the “Regulated Project Approval Process” with relative Gateways (A to E)

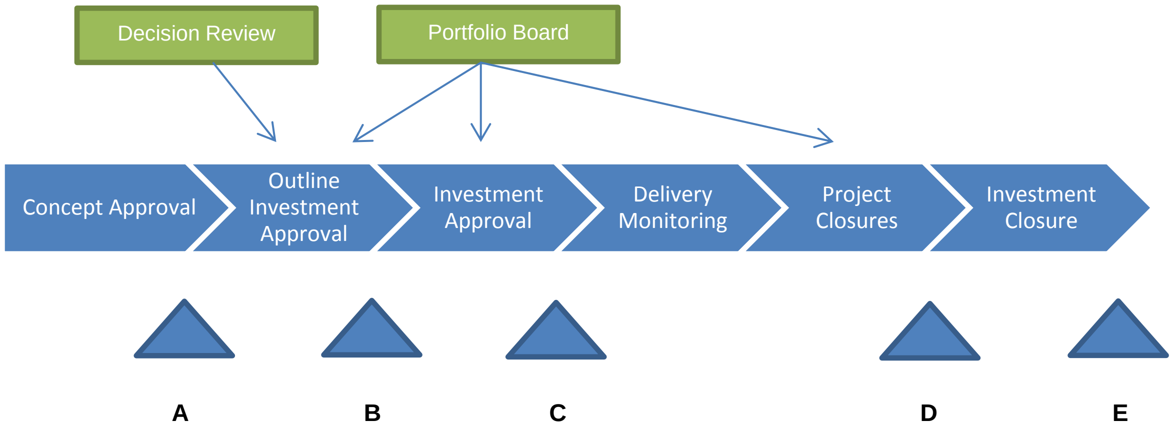

Figure 26: Project Investment Gateway process

Each Stage / Gate within the process is further described below.

Stage	Gate	Description
Concept Approval	A	This is the point at which an opportunity or business need is first identified (usually by the Regional Development Plans), and approval of the concept in principal is sought from the Head of System Development prior to proceeding to the next Gate. NAMP projects are directly fast tracked to Gate B.
Outline Investment Approval	B	This is the point at which approval of the preferred option is sought prior to proceeding to the next Gate. For NAMP projects this is the point where all the options have been considered and the Planners share their preferred solution to the Delivery Team for development into the full investment form
Investment Approval	C	This is the point at which Planners and the Delivery Team establish the detailed preferred solution. Also, this is when the capital expenditure values for NAMP Projects are approved
Delivery Monitoring		This is the stage in which the project is monitored to ensure efficient delivery
Project Closures	D	This is the point at which the project is complete and a review is carried out to assess its success in order to identify best practice and capture the lessons learned and closing out SAP

Investment Closure	E	This is the point at which the Investment is closed and the benefits, if any, stated in the Investment form, are measured

Table 51: Project Governance Gate Stages

Further details on the overall NAMP development roles and responsibilities can be found in Document EDP 08-0300, whilst document EDP 08-0301 deals with the overall NAMP Change Control Process.

For information and process flows associated with the governance are shown below.

PG&C Project Gate A Approval to Gate E Review

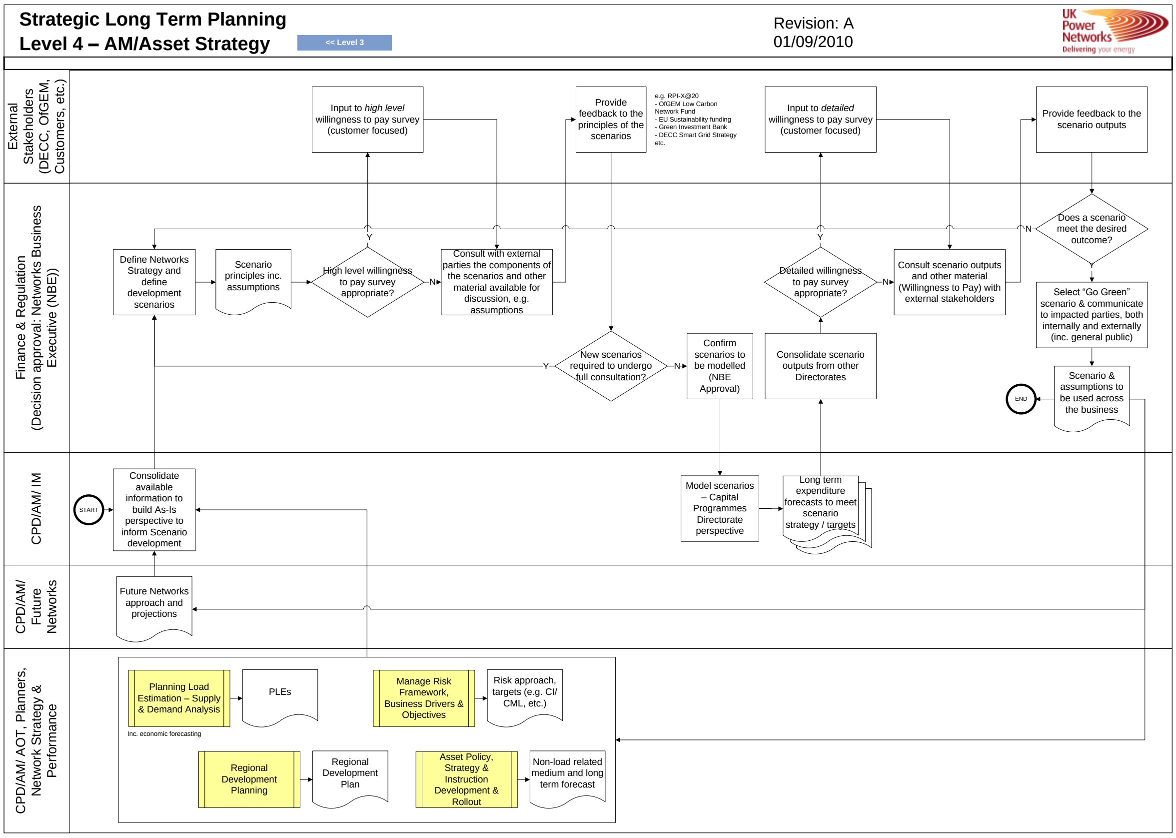

Figure 27: High level view of scenario planning.

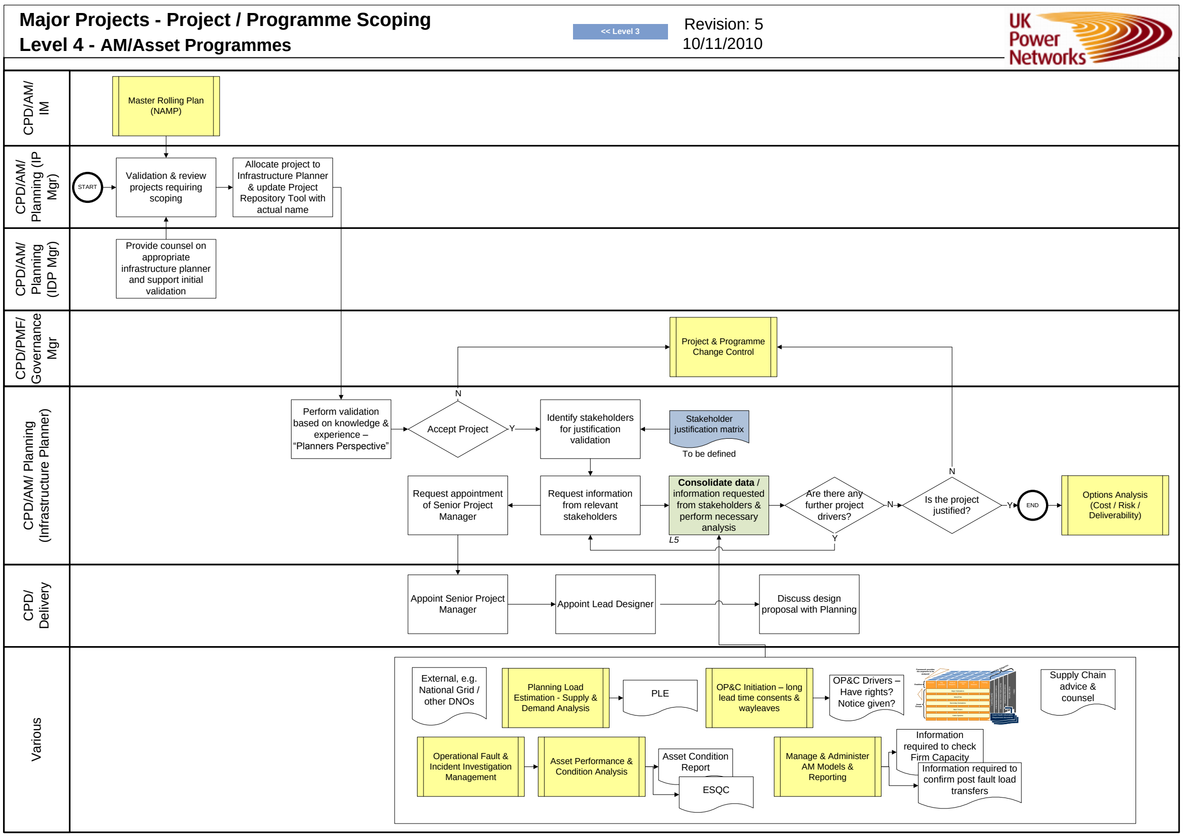

Figure 28: Specific project validation

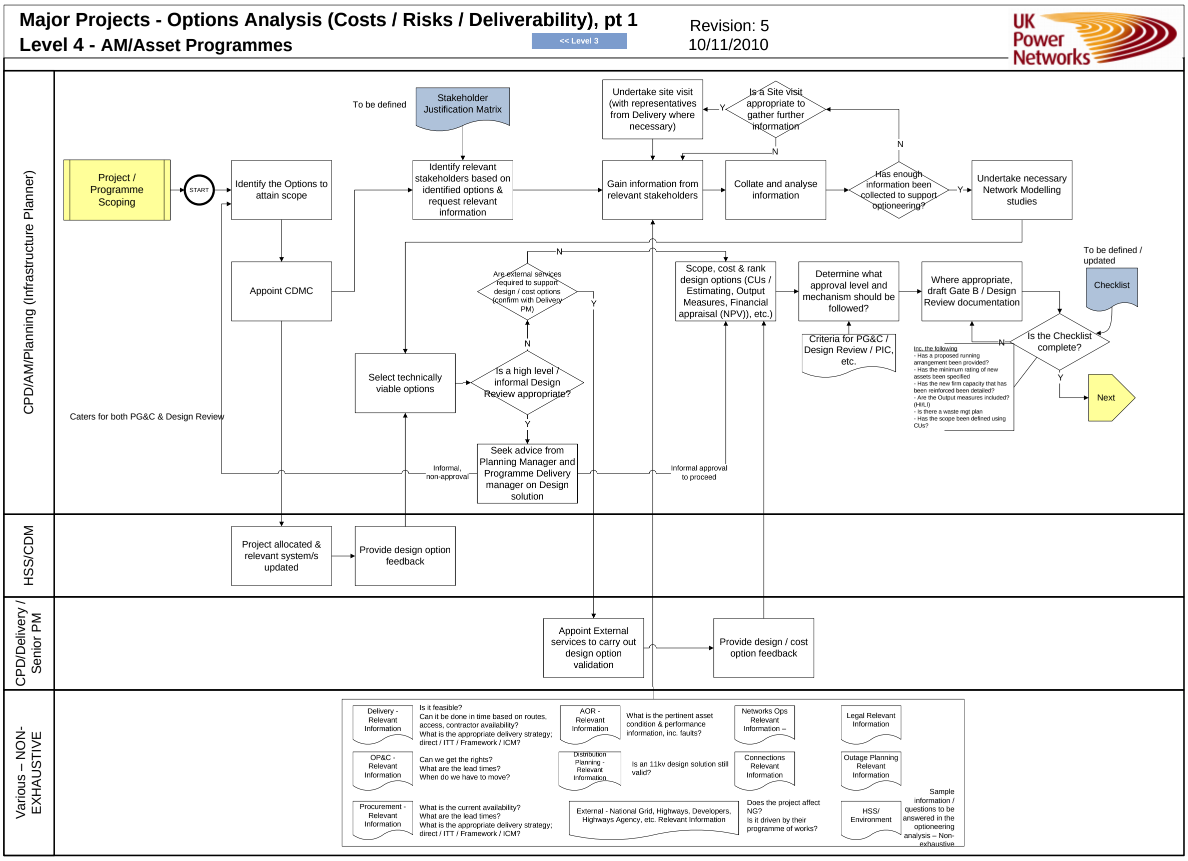

Figure 29: Specific project scoping up to Design Review

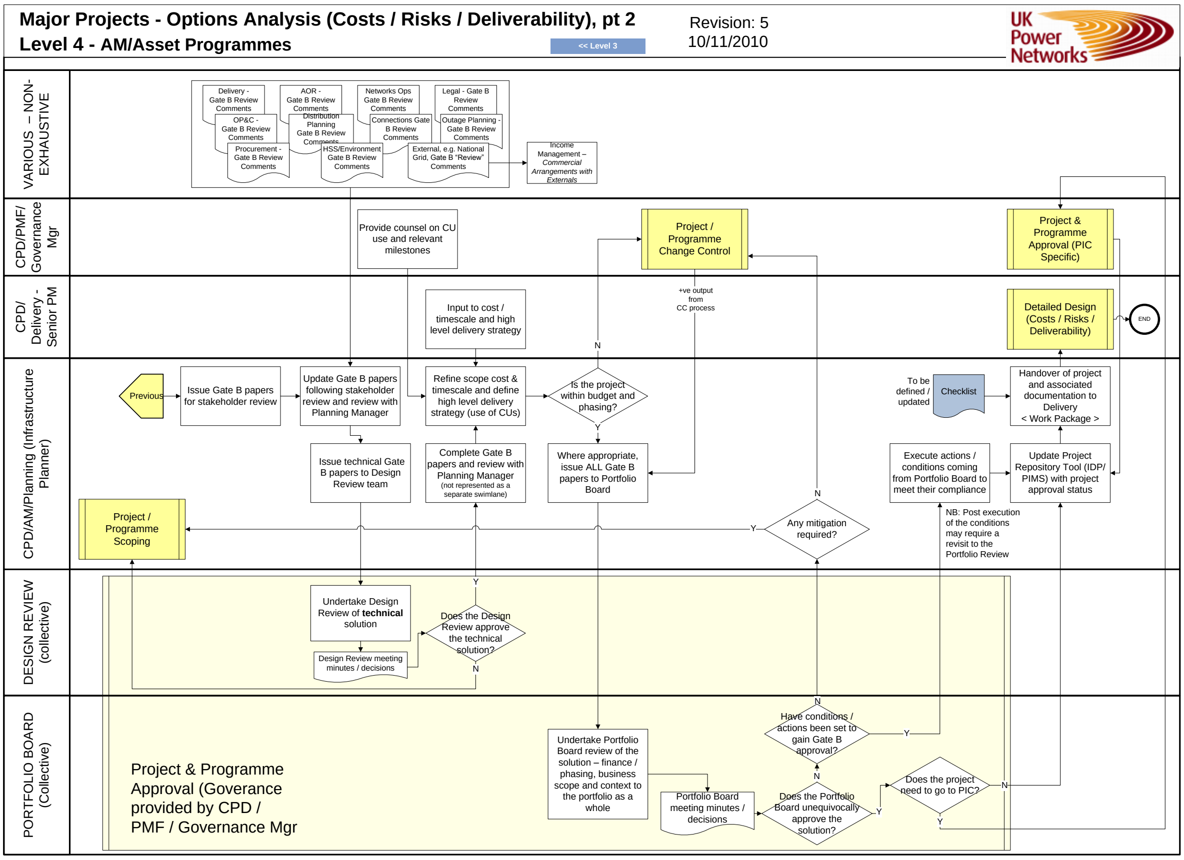

Figure 30: Specific project scoping from Design Review through Gate B to Delivery handover

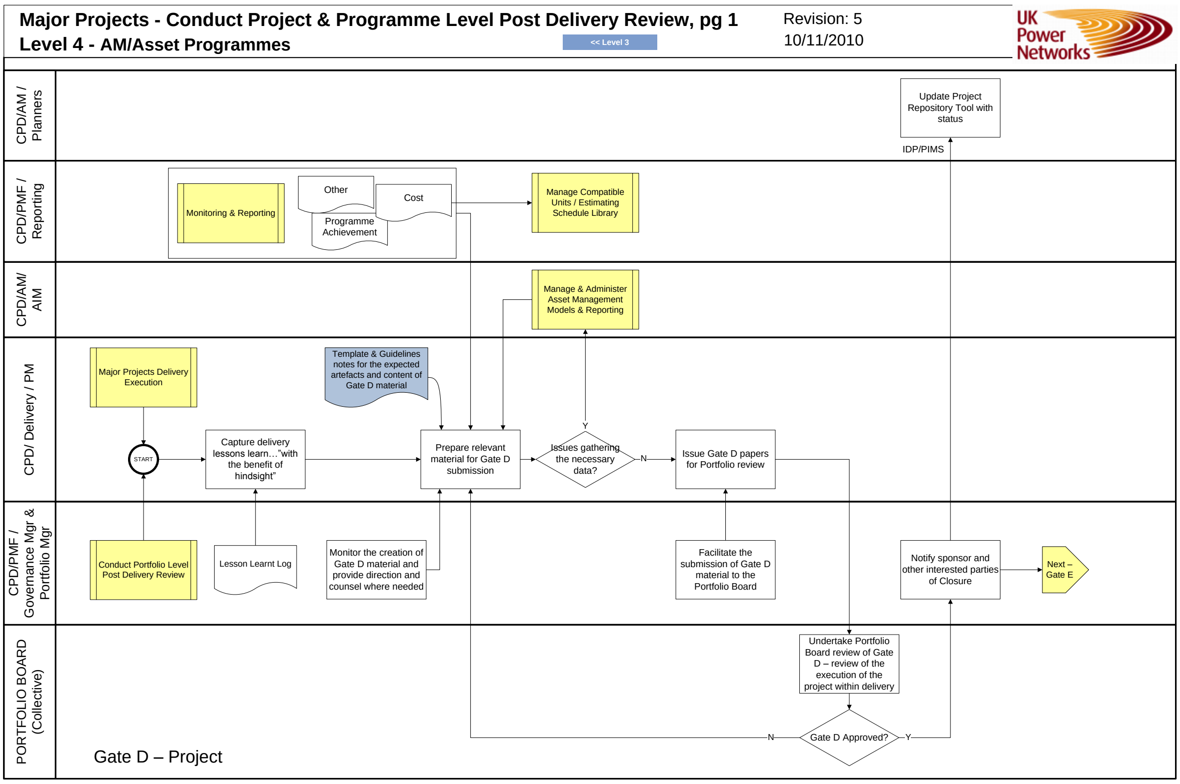

Figure 31: Specific Project Gate D Project Closure

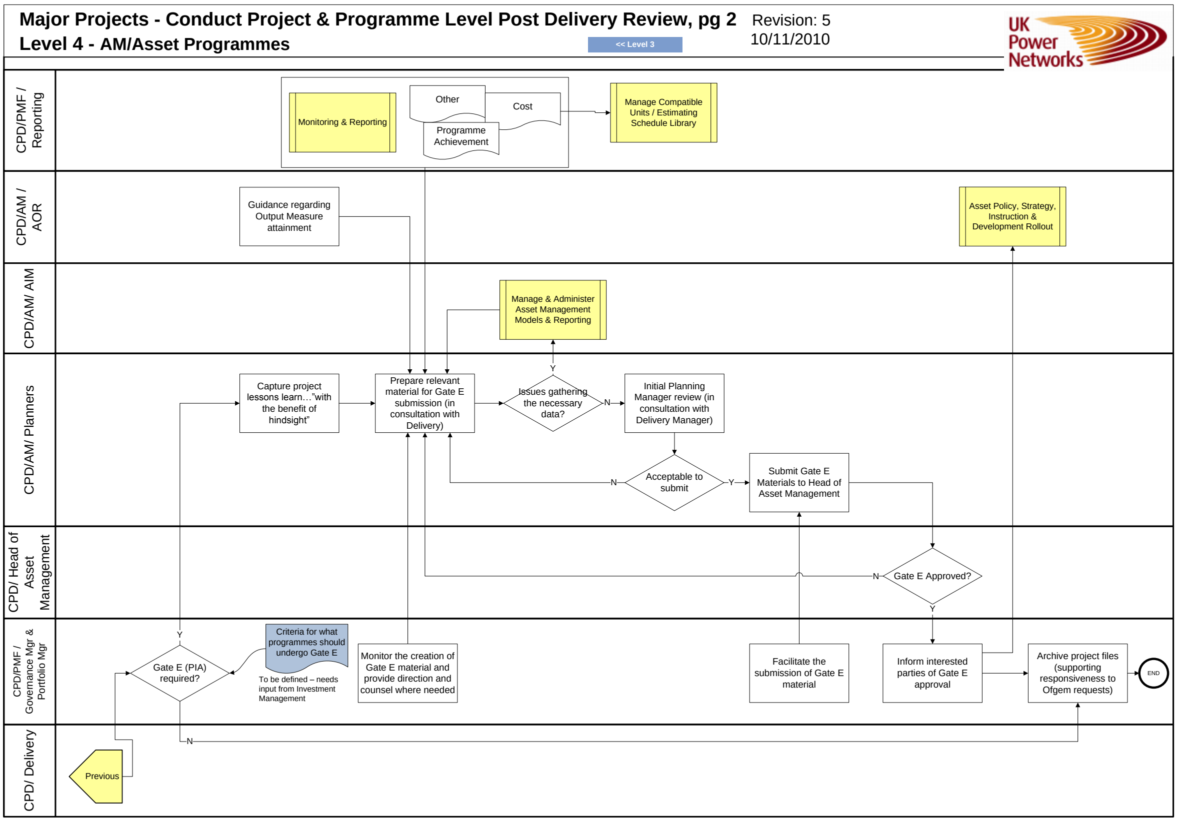

Figure 32: Specific Project Gate E Project Review