RIIO-ED1

Investment Justification

Load related expenditure

Network: EPN

Version 1.4

Document History

Version	Date	Revision Class	Originator	Section Update	Details
1.4	3/03/2014	Minor	Robert Kemp	1.1	Changed Text
1.4	3/03/2014	Major	Robert Kemp	1.2	Change figure 1 and table 1 to align figures to the 19th February NAMP version J less indirect costs
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Version	Date	Revision Class	Originator	Section Update	Details
					reflect new costs and removal of scheme detail as this now available in Gate A papers
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Version	Date	Revision Class	Originator	Section Update	Details
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1.4	5/03/2014	Major	Robert Kemp	3.5	Amend HVP scheme to reflect gate A papers
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Contents

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V1.1	21/06/2013	Minor Clarification to LI table	Robert Kemp
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1.0 Executive Summary

1.1 Scope

This document provides detailed justification for UK Power Networks load-related expenditure for the ED1 period in the Eastern Power Networks area (EPN).

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

We include all of the expenditure for EPN for expanding and extending our network driven by general load growth, fault level 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 total £398m (excluding betterment and NRSWA) and 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 including demand growth, this forecast expenditure will ensure that we meet our licence obligations, maintain network capability (as measured by the Load Index) 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	£54,651	£54,745	£50,117	£45,064	£47,310	£49,324	£51,491	£45,296	£397,999

Table 1: EPN Forecast Plan 2015/16 - 2022/23 for LRE Total £398m 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 break down evolves by year within the ED1 period.

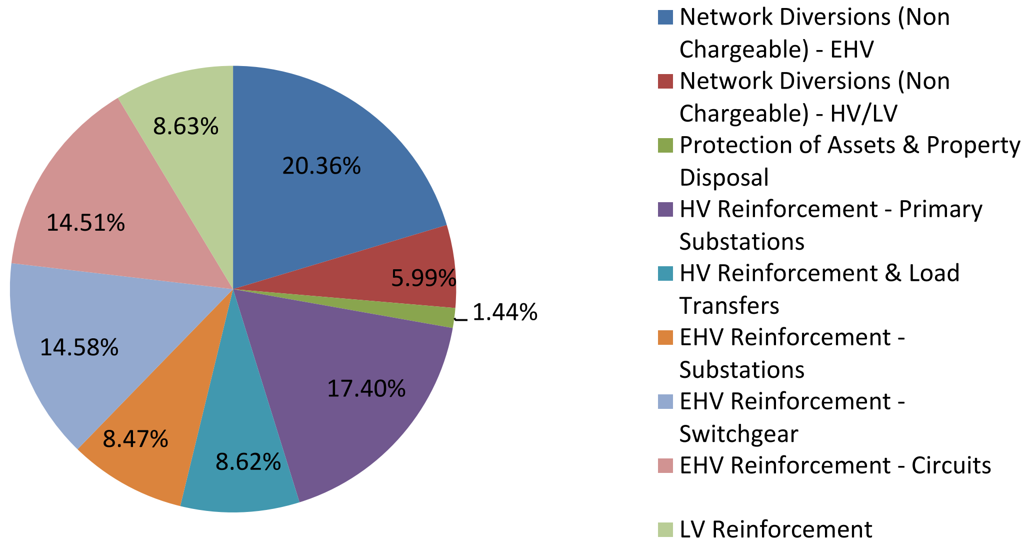

Figure 1: EPN Load Related Expenditure for ED1 (source Table J less indirects from 19Th February 2014 NAMP Baseline)

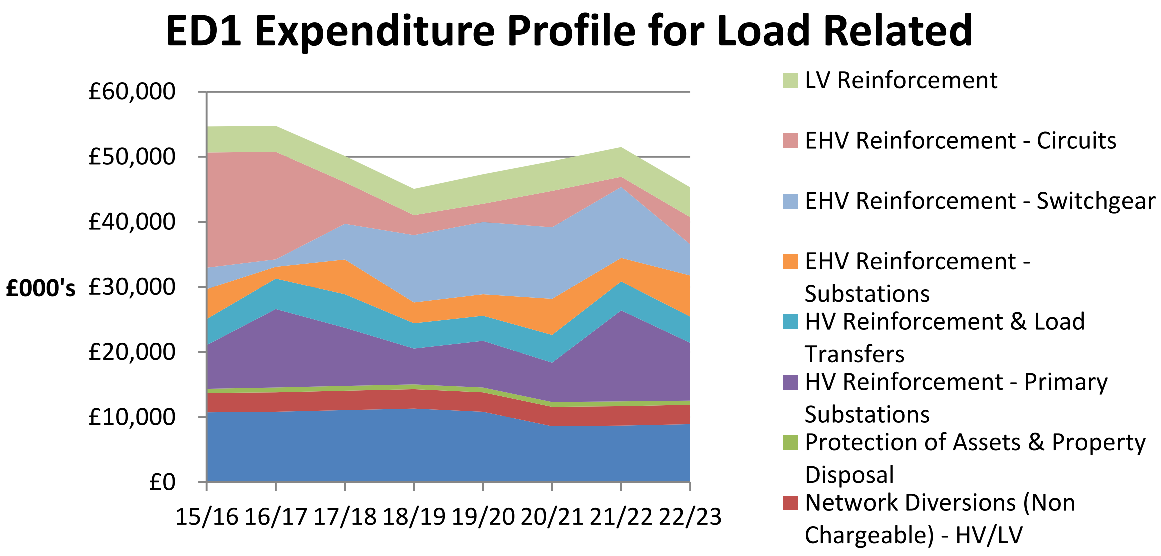

Figure 2: EPN split of the load related activities shown per regulatory year over the ED1 period (source Table J less indirects from 19Th February 2014 NAMP Baseline)

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

Category	Total per Category
Network Diversions (Non Chargeable) - EHV	£1,045
Network Diversions (Non Chargeable) - HV/LV	£23,828
Protection of Assets & Property Disposal	£5,729
HV Reinforcement - Primary Substations	£69,238
HV Reinforcement & Load Transfers	£34,290
EHV Reinforcement - Substations	£33,722
EHV Reinforcement - Switchgear	£58,026
EHV Reinforcement - Circuits	£57,763
LV Reinforcement	£34,358
Total	**£397,999**

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

Our forecast expenditure will ensure that we meet our licence obligations, maintain network capability and provide new connections for new demand and generation.

As a result of our planned expenditure we are committing to deliver a Load Index output. Our investment plans aim to deliver a small decrease in the number of LI 4/5 sites starting with a forecast of 25 sites at the start of ED1 and with a forecast output of 18 LI4/5 sites at the end of the ED1 period.

Table 3 below shows how our forecast end point for DPCR5 has changed compared to the October 2012 report to Ofgem. The change results from the change in our demand forecast, adding latest delivery information, and the changes to LI definitions and banding. This has changed our forecast start point for ED1 (end point for DPCR5) from 38 to 25 LI4/5 sites in 2014/15, largely driven by the lower than forecast demand.

DNO	DPCR5 year 0 position	DPCR5 End	Actual 2011/12	Oct 2nd 2012 Ofgem return for 2014/15 forecast	2014/15 Forecast Start ED1	ED1 End Forecast
EPN with investment	86	56	41	38	25	18
Old site load growth forecast and DPCR5 LI definitions and banding					New site load growth forecast and new LI definitions and banding	

Table 3: EPN 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. . Figure 3 below show's our networks utilisation (actual and forecast) over the DPCR5 period versus the industry average (red line). All show that we are operating more of our sites at a higher utilisation than other DNOs (based on 2011/12 LI data share information).

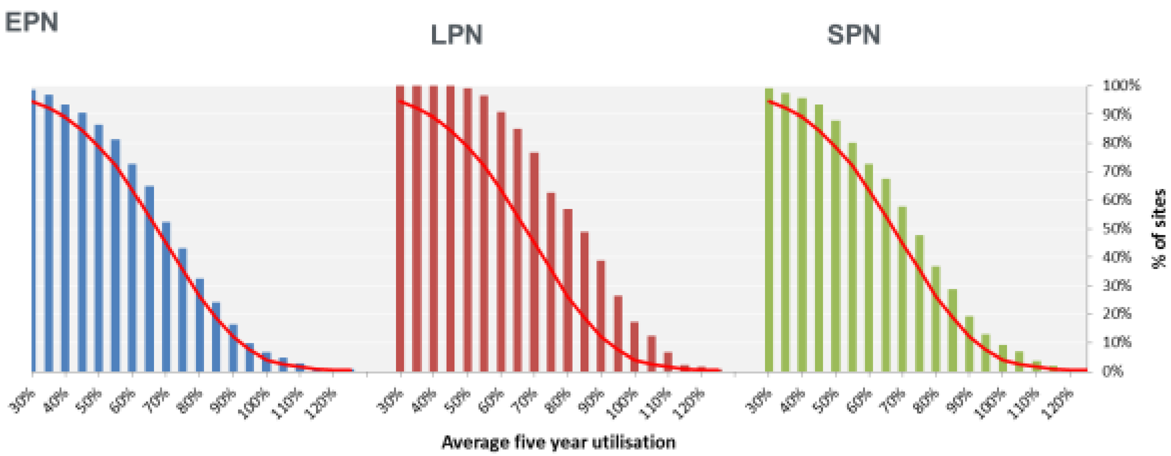

Figure 3: UK Power Networks site utilisation by licensed area

Our ED1 plan is based on the delivery of the outputs we committed to during the DPCR5 period. We have delivered these while also under spending against the agreed Allowance by £150.5m (49%). Our customers will benefit from this underspend, receiving 55% back in the next period.

The annual average forecast spend in the ED1 plan is 19% 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 which has been negative. In ED1 by contrast our system forecast shows an increase of approximately 405MW from 6605MW in 2013 to 7010MW in 2023.

This translates into peak site growth that varies across the network. The increase in peak load is driven by economic recovery, the uptake in electric vehicles (EV) and (to a lesser extent) heat pumps. Over the ED1 period the contribution to the annual growth in demand associated with EV and heat pump increases. By 2023, 74% of the growth in peak demand (at a system level) is due to heat pumps and EVs.

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 Section 4.5).

Spend in DPCR5 has been lower than expected due to lower load growth, consents issues and implementation of more economic technical solutions that emerged due to changes in local circumstances (refer to Section 3.6 for more information). We believe that this proposed 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 or earlier economic recovery.

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's 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. increasing instances of Summer Peak demands due to penetration of Air Conditioning load.

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 emission**s.** This is expected to change patterns of electricity consumption and increased 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).

Figure 4 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.

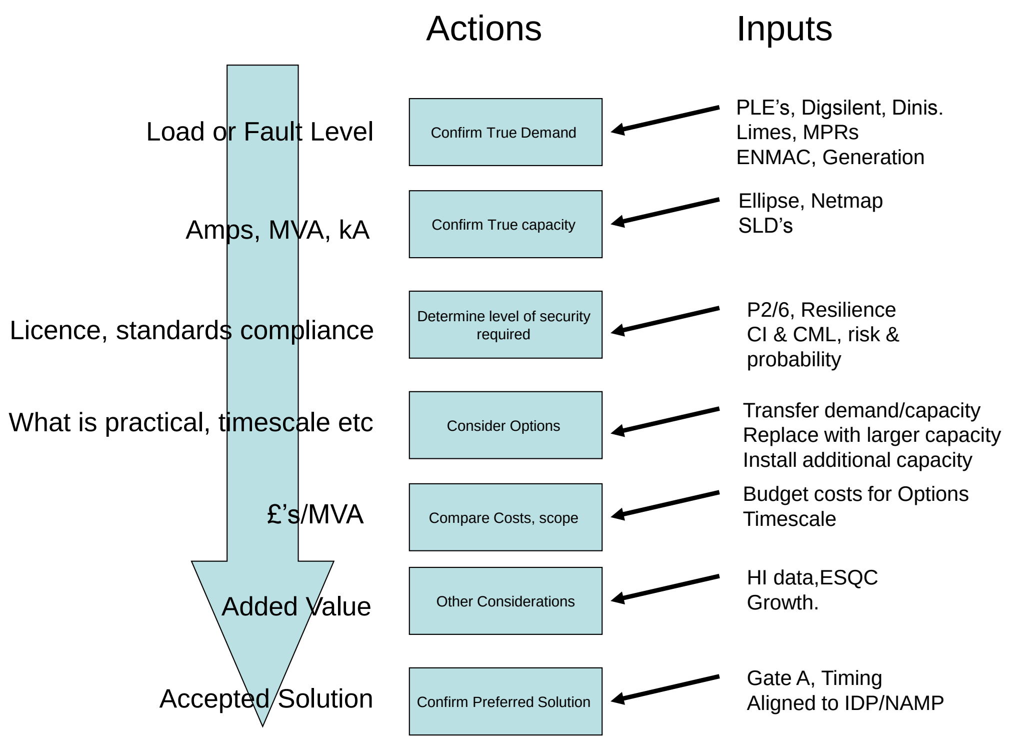

Figure 4: Overview of Reinforcement Planning Process

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 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.

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 could be deployed and indicative financial benefits.

The outputs of the PLE, LRE and Transform models provide a robust first-pass assessment of where investment may be needed due to load growth and smart solutions may be possible.

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 network 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 standard, which is part of our License condition, provides a minimum standard to ensure that the network is managed to specified security of supply criteria. To maintain EPN's compliance with P2/6, it is vital that we address any potential issue well in advance. For this reason, projects driven by P2/6 considerations are given priority.

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

To help identify 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 required interventions 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 Section 4.4, and 4.5.

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.

Within EPN 20 Regional Development Plans have been established to match the network to the corresponding National Grid Exit points

RDP01	Walpole GSP
RDP02	Walpole GSP - Peterborough
RDP03	Norwich GSP
RDP04	Norwich City
RDP05	Burwell GSP
RDP06	Eaton Socon GSP
RDP07	Sundon & Amersham GSP
RDP08	Pelham & Wymondley Group
RDP09	Bramford GSP - West
RDP10	Bramford GSP - East
RDP11	Bramford GSP - Ipswich - Cliff Quay
RDP12	Bramford GSP - Coast
RDP13	Elstree & Rye House GSP
RDP14	Elstree & Watford South Group
RDP15	Elstree & Mill Hill & Willesden GSP
RDP16	Brimsdown & Tottenham GSP
RDP17	Rayleigh & Braintree Group
RDP18	Rayleigh & Bramford Group
RDP19	Rayleigh & Tilbury Group
RDP20	Warley & Barking & West Thurrock GSP

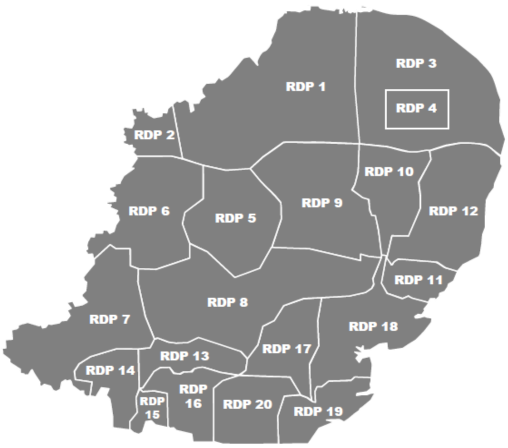

Figure 5: RDP Geographic Locations

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 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. Figure 6 below provides an overview of demand growth in the EPN area as per our “Core Scenario”.

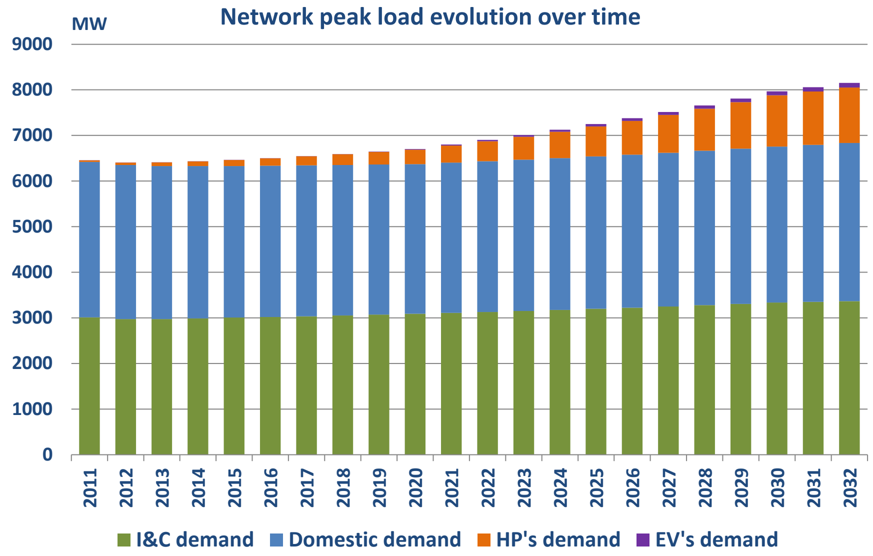

Figure 6: Overview of Demand Growth in EPN

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 maximum demand is expected to grow by 8.4% of which 74% is due to EVs and 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 (refer to Appendix Section 4.5).

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

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 around our Core Scenario can be seen in CV103. This document focusses on our own Core Scenario.

Our reinforcement plans consist of two main spend areas, i) diversions and investments driven due to third party 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 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 tables below show the expenditure 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. 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	0.2	0.3	-	
7	Secondary network	HV/LV	1.4	2.3	1.6	The increase in expenditure is due to a higher number of distribution transformers being replaced. This is the result of load diversity and uptake of new technologies (e.g. HVs and Evs)
8	Secondary network	HV/HV	2.9	4.6	0.8	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). In addition to that please note that switchboard reinforcement that is consequential to an increase in transformer capacity would be included in CV101 row 10.
9	Primary network (n-1)	EHV/LV	-	-	-	
10	Primary network (n-1)	EHV/ HV	35.9	57.4	62.3	The majority of the expenditure in this category is dedicated to reinforcement of our 33kV/11kV substations and circuits to ensure that significant localised growth and diversity effect do not endanger network security. The incremental steps in forecasted load

						growth make this type of intervention optimal when compared to expensive primary substation reinforcement. Due to constraints factors like space and equipment ratings in the local network, it is often more economical to add a new substation rather than upgrading all the asset ratings on multiple substations. Please refer to "HV reinforcement - substations" and "EHV reinforcement - circuits for further details
11	Primary network (n-1)	EHV/ EHV	3.4	5.4	1.1	As opportunities to improve transformer utilisation decrease, we expect limited expenditure in this category.
12	Primary network (n-1)	132/LV	-	-	-	
13	Primary network (n-1)	132/HV	4.9	7.8	1.5	Reduction in spend as options to replace switch gear only decrease due to space availability
14	Primary network (n-1)	132/ EHV	9.7	15.5	20.3	The increase in expenditure is due to projects that are driven by local demand condition (e.g. connection of data centres and rapid increase in urban developments) or embedded generation. In addition to that the complexity of the intervention is also increasing as the optimal site scale threshold is surpassed (e.g. adding a 3rd transformer to the site). Please refer to section "EHV reinforcement - substation" for further details
15	Primary network (n-1)	132 /132	0.6	1.0	-	
16	Primary network (n-2)	EHV/LV	-	-	-	
17	Primary network (n-2)	EHV/ HV	-	-	-	
18	Primary network (n-2)	EHV/ EHV	-	-	-	
19	Primary network (n-2)	132/LV	-	-	-	
20	Primary network (n-2)	132/HV	-	-	-	
21	Primary	132	1.0	1.6	21.4	The rise in connection request for

	network (n-2)	/EHV				distributed generation is the driver behind the increase in this expenditure line. As a result we forecast that a new grid substation will be required in the March / Peterborough area. Please refer to "EHV reinforcement - substation" section for further details
22	Primary network (n-2)	132/ 132	0.1	0.2	22.7	This expenditure is driven by the need to reinforce the grid as a consequence of reduced impedance in the network due to additional National Grid Exit Points (Bainton and Eaton Socon). In addition to that, increasing load in the Stowmarket area is expected to require N-2 reinforcement in the network.
23	**Total**		60.0	96.0	131.6	The increase in expenditure is in line with load growth expectations and the impact of distributed generation on our assets

	Circuit reinforcement - Secondary network		DPCR5	DPCR5 8 year	RIIO-ED1	
		Voltage	(£m)	(£m)	(£m)	
29	Secondary network	LV	7.2	11.6	20.4	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 revealed 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	14.4	23.1	32.4	
32	Secondary network	HV				
33	**Total**		21.7	34.6	52.8	
34						

	Circuit reinforcement - Primary network		DPCR5	DPCR5 8 year	RIIO-ED1	Commentary
		Voltage	(£m)	(£m)	(£m)	
40	Primary network (n-1)	EHV	11.8	18.8	16.3	There is a small decrease in EHV circuit reinforcement in ED1 Please refer to "EHV reinforcement - circuits" for further details.
41	Primary network (n-2)	EHV	-	-	1.9	
42	Primary network (n-1)	132 kV	9.8	15.7	23.3	The increase in 132kV circuit reinforcement is consequential to our work on grid substations and rearrangements. The expenditure also includes actions to enable smart interventions like dynamic rating. Please refer to "EHV reinforcement - circuits" for further detail
43	Primary network (n-2)	132 kV	0.0	0.0	6.8	
44	**Total**		21.6	34.6	48.4	

	Voltage regulation schemes		DPCR5	DPCR5 8 year	RIIO-ED1	Commentary
		Voltage	(£m)	(£m)	(£m)	
50	Secondary network	LV	9.6	15.4	22.0	This spend reflects the anticipated increase in LV schemes to address latent issues that we expect to be revealed 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)
51	Secondary network	HV	-	-	-	
52	Primary network (n-1)	EHV	-	-	-	
53	Primary network (n-1)	132 kV	-	-	-	
54	Primary network (n-2)	EHV	-	-	-	
55	Primary network (n-2)	132 kV	-	-	-	
56	**Total**		9.6	15.4	22.0	

	DSM payments *(into subscriptions)*	DPCR 5	DPCR5 8 year	RIIO-ED1	
		(£m)	(£m)	(£m)	
62	LV			-	Increasing utilisation of DSR for supporting reinforcement works, de-risking construction outages
63	HV			0.8	
64	EHV			-	
65	132 kV			-	
66	**Total**			0.8	

	Fault level Reinforcement Schemes: Fault issues on switchboard/substation busbars		DPCR5	DPCR5 8 year	RIIO-ED1	
			(£m)	(£m)	(£m)	
121	**All Scheme Types**	**All**	6.7	10.7	32.2	There has been an increase in generation activity in the last few years, particularly for connection to the 33kV network, which has contributed to the increase in fault level at Grid substations to values close to or exceeding the design limit of the equipment to which it is connected. Please refer to the "EHV reinforcement - switchgear" schemes

	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**	0.1	0.1	-	

Table 4: RIG's mappings to CV101 lines

Table 5 shows the forecasted expenditure 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. Please refer to Section 3.3 for further details.

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	0.0	0.3	Refer to section below on Diversions and investments due to third party actions
Conversion of wayleaves to easements, easements, injurious affection	HV	0.4	0.7	4.0	
Conversion of wayleaves to easements, easements, injurious affection	EHV	0.7	1.1	3.5	
Conversion of wayleaves to easements, easements, injurious affection	132kV	18.5	29.6	36.4	
Diversions due to wayleave terminations	LV	9.9	15.8	16.0	
Diversions due to wayleave terminations	HV	11.6	18.6	7.8	
Diversions due to wayleave terminations	EHV	3.3	5.3	3.7	
Diversions due to wayleave terminations	132kV	2.5	3.9	39.0	

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 maintaining our assets on third party land.

3.3 Diversions and other investments 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.

Of the total asset base approximately 70% is estimated to be on wayleave consents, 20% on a permanent easement and 10% on no consent (due to reasons like changes in property rights from 'public'/ customers own to private).

There are increasing demands from Grantors (mostly encouraged by agents) to claim injurious affection for diminution in value of property. At present these have mostly been associated with 132kV network but as the number of these diminishes there will be a move to the lower voltage wood pole lines. The basis of these claims is made under various parcels of legislation, but in particular The Electricity Act 1989 and The Land Compensation Act 1961 and 1965. This issue also affects the rest of the DNOs.

The alternatives to settling a claim are to seek a “Necessary Wayleave” or to divert the overhead line. In order to proceed with the Necessary Wayleave process there is a need to establish that it is either Necessary or Expedient to retain the equipment in its current location. Provided this test can be satisfied the option of an application to DECC for a Necessary consent is possible and this procedure would not be started if there is a chance of failure. Once the Hearing Process has finished it is expected the Secretary of State would grant the “Necessary Wayleave”, however this would only be for a 15 year term after which the landowner would be at liberty to terminate the consent again. Compensation would still need to be paid and should the parties be unable to agree the level of compensation this would lead to a referral to the Lands Tribunal to assess the compensation. In using these powers the cost of the process, manpower including the potential compensation, is high. On the other hand, diversions are often technically difficult and expensive, especially with regard to the 132kV assets.

Whilst the issue of diversion and other investment due to third party action primarily affects overhead lines, it can also apply to underground cables that are held on terminable wayleaves. There have also been situations where new developments prohibit access to the assets for maintenance or replacement purposes, leaving little option but to relocate the infrastructure.

In some cases it is possible to negotiate with the landowner, which can involve expenditure in terms of assets being moved (diversion) or compensation being paid to landowner in return for a permanent easement (defence of assets). However in a certain number of cases agreement cannot be reached and the matter has to be referred to DECC for a determination, which may require the asset to be moved or enable it to be retained. In the latter situation the case may be referred to the ‘Lands Tribunal’ to adjudicate on the amount of compensation payable to the landowner if this cannot be agreed between the parties.

Generally the costs associated with the use of Statutory Powers means it is unlikely they will be used in relation to LV / HV equipment but there are instances where there is no practical alternative but to use the legislation. Payments are made to retain an asset either by an easement or the extending of a leasehold or purchase of the freehold. If 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.

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.

3.3.2 Network Diversions (Non-Chargeable) – EHV

Investment drivers

The majority of the 132kV and 33kV network crossing 3rd party land are held on the basis of a terminal wayleave agreement. This expenditure category is the result of i) landowners terminating the wayleave agreement to facilitate development of the land and the network having to be relocated or ii) as a means of seeking enhanced payments for the equipment. In addition to that, situations 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. Generally, due to the nature of the pre-existing consent it is not possible recoup these monies back from the developer.

ED1 forecast

Our ED1 forecast for 132kV/EHV diversions is £81.1M and is £41.4M higher than DPCR5 spend (on an 8-year basis). Table 6 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP Line	DPCR5 £k (8 years)	EDI £k	RIGs Code/Line
1.11	39,672	81,045	CV1 8-9 CV1 13-14

Table 6: ED1 forecast expenditure (source Table J less indirects from 19th February 2014 NAMP Baseline)

Out of the £81M allowance, £39.3M is a provision which is included in the ED1 forecasts for 132kVand 33kV compensation events and acquisition of permanent easements. The level of Injurious claims are expected to remain at current levels through the ED1 period, but the average monetary value of each claim is expected to remain constant, if not slightly higher as property and land prices continue to recover through the ED1 period. In addition, UK Power Networks has seen an increase in the opportunity to proactively secure the remaining sections of its major infrastructure on permanent rights, as grantors seek a one-off consideration from the remaining network asset crossing their property.

Table 7, shown below, provides a more detailed view of the ED1 forecast expenditure.

Type	Project ID	Description	ED1 £k
1.11	3439	Trowse Grid - Divert the 4 x Trowse/Thorpe Circuits (PVB & PMB)	13,569
1.11	5628	PQF 132kV Route - Underground Due to Southbank Development	2,908

1.11	2687	EHV Diversions - EPN	3,737
1.11	3817	Earlham/Sall 132kV double circuit (PS) : Diversions	5,178
1.11	6352	Underground HB & PLG 132kV Routes at Walpole GSP (Kings Lynn Circuits)	3,429
1.11	8540	Beaulieu Park / Boreham Interchange Development PGF Diversion	7,400
1.11	8541	132kV Diversions - EPN	5,510
1.11	6861	132kV Compensation & Deeds of Grant Costs	35,653
1.11	6862	EHV Compensation & Deeds of Grant Costs	2,641
1.11	2988	Divert 132kV Cables - Ipswich Wet Dock	1,020

Table 7: EHV Network Diversions (source Table J less indirects from 19th February 2014 NAMP Baseline)

It is important to note that other circuits may require diversion during the ED1 timeframe as EHV schemes can take typically between 2-5 years to come to fruition.

There is an increase in costs that relates to conversions of wayleaves and injurious affection as Land Agents and Developers take an increasingly more aggressive stance and actively seek opportunities for compensation.

Table 8 below illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
A greater than forecast upturn in economic activity could increase expenditure. As more assets require moving to allow developments to proceed.
Land Agents and Development becoming more aggressive on wayleave terminations
Embedded generation projects can conflict with overhead line assets as developers acquire land in close proximity to the network
Opportunities
To optimise other projects into any required diversion.
Improve CI/CML performance regarding OHL circuits following diversion/undergrounding
Realise circuit capacity reinforcement as part of diversion / undergrounding

Table 8: Risks and Opportunities potentially affecting the forecast

3.3.3 Network Diversions (Non-Chargeable) – HV/LV

Investment drivers

The majority of the 11kV and LV network crossing 3rd party land are held on the basis of a wayleave agreement. In addition, a significant number of substation leases are presently 'holding-over' on expired terms. The source of this expenditure is as a consequence of a landowner terminating the wayleave agreement or a landlord submitting a section 25 notice, under the Landlord and Tenant Act 1954.

ED1 forecast

Our ED1 forecast for HV/LV diversions is £23.8M and is £10.6M lower than DPCR5 spend (on an 8-year basis). Table 9 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP Line	DPCR5 £k (8 years)	EDI £k	RIGs Code / Line
1.12	**34,416**	**23,828**	**CV1 11-12**

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

The source of this expenditure is from the review of historical trends together with known 'live' schemes. This expenditure would be managed with the aid of the legal regime over the period to ensure an optimum settlement is reached for the benefit of both sides. Likewise, if the network is to be relocated, its timing is managed to ensure a coherent network alteration is adopted that adds engineering value to the network and, where possible, is tied to pre-existing planned network improvement works.

Table 10 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
Land Agents becoming more aggressive on wayleave terminations
Government forecasts show an estimation increase of around 17% in new household formation which, if proved to be an underestimation, could result in an increase in wayleave terminations

Increased development of solar farms can conflict with overhead line assets leading to additional diversion requests
Opportunities
Negotiate retention
To optimise other projects into any required diversion.
Opportunity when negotiating to gain easements on all equipment and defer future wayleave costs
Improved CI/CML performance regarding OHL circuits following diversions / undergrounding
Realise circuit capacity reinforcement as part of the diversion undergrounding
Underground HV/LV that cross higher voltage circuits to provide continuity of supply for maintenance works
Resolve low clearance or other ESQC issues

Table 10: Risks and Opportunities potentially affecting the forecast

3.3.4 Defence of Assets

Investment drivers

The source of this expenditure is the cost associated with retaining the network in situ following receipt of a termination notice. This would be through either the acquisition of a permanent right, such as an easement or freehold, or by agreeing terms for a new leasehold interest in the land. Where a negotiation is unsuccessful, costs are expended to retain the network in situ through the necessary wayleave process or the network is diverted, see Section 6.2.

ED1 forecast

Our ED1 forecast for asset defence is £5.8M and it is £4.8M higher than DPCR5 spend (on an 8-year basis). Table 11 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP Line	DPCR5 £k (8 years)	ED1 £k	RIGs Code / Line
1.16	904	5,729	CV1 6-9

Table 11 (source Table J less indirects from 19th February 2014 NAMP Baseline)

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, have and will expire.

Increasingly, local authorities and large institutional property owners are seeking to re-negotiate, en bloc, the terms if 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. EPN is currently negotiating with London Borough of Haringay (22 sites), London Borough of Enfield (24 sites) and London Borough of Harrow (53 sites) on the terms of future substation leases

Typically, today, a rent for a distribution substation could range between £300 to £750 per annum and could be subject to RPI indexation. As the availability of land becomes increasingly scarce in our urban environments, land prices will increase. 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 operational property portfolio.

Table 12 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.
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
Seek to Purchase distribution sites when leases expire
Pro-actively secure deeds for high risk & urban network

Table 12: 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).

3.4.1 EHV Reinforcement – Substations

Investment drivers

EHV reinforcement at Grid substations encompasses a range of activities including major projects such as 132/33kV or 132/11kV transformer replacement, 33kV switchgear replacement as well as other minor projects such as, CT replacement, 33kV transformer tail replacement and additional transformer cooling.

The primary investment drivers for this expenditure category are:

- 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 due to lack of substation reinforcement matching the impedance decrease. We expect additional expenditure in this category as a consequence of the proposed exit point at Bainton and the Eaton Socon High Value Project.

  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 2x90MVA 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 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 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 for EHV reinforcement substations is £33.7M and is £7.8M lower than DPCR5 spend (on an 8-year basis). Table 13 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP Line	DPCR 5 £k (8 years)	ED1 £k	RIGs Code / Line
1.35	**41,500**	**33,722**	**CV101 11 CV101 13-15 CV101 18 CV101 20-22 CV101 52-55**

Table 13 (source Table J less indirects from 19th February 2014 NAMP Baseline)

This decrease is due to relatively low rates of load growth expected in ED1 compared with our expectation of load growth in DPCR5. The effect of this is that at 132kV and EHV level we see lower spend, as further large steps in capacity are not forecast to be required for ED1 (given the delivery of projects in DPCR5). The effect of this is that we planning smaller incremental steps of capacity to meet load growth based on interventions at lower voltage levels (e.g. 11kV) rather than at EHV level.

Table 14 provides contains further details of the EHV reinforcement substations, further information can be found in the gate A scheme papers and the regional development plans. The table lists all interventions over £1M.

Type	Project ID	Description	ED1 £k
1.35	2365	March Grid 132/33kV Grid Substation - ITC (2 x 90MVA Units)	2,944
1.35	2409	Rye House 132/33kV Grid Substation - Improved Transformer Utilisation	1,150
1.35	3788	(RDP - Crowlands) Gidea Park Proposed 132/33kV Grid Substation - (2 x 90MVA)	8,762
1.35	3798	(RDP - Fleethall/Southend) Fleethall 132/33kV Grid Substation - ITC (2 x 90MVA)	3,518
1.35	3873	Ipswich 132/33 Grid Substation - ITC (2 x 90MVA units)	1,884

1.35	6353	Trowse 132/33kV Grid Substation - Install 3rd 132/33kV GT and Replace 33kV Switchboard	3,010
1.35	3847	Writtle St & West Chelmsford FFC Circuits - Reinforce	1,552
1.35	3950	Clacton Grid /Old Road Tee - Reinforce 33kV Circuit	1,151
1.35	3653	Bainton Proposed 400/132kV Exit Point (N-2)	5,137
1.35	8529	DG - Proposed new Grid Substation Between March and Peterborough	6,036

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

Table 15 illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in economic activity over that predicted could increase loading beyond our forecast.
Concentration of network on existing sources will reduce resilience under N-2 outage scenarios.
Network-wide load increases may require interventions on adjacent sites within the same time period requiring reinforcement to be brought forward.
True load is masked by embedded generation which may not be available when most needed.
New customer connections take existing headroom at EHV substations bringing reinforcement need forward.
New 132kV transformers increase the overall 132kV earth fault level.
Opportunities
Removal of high HI plant
DTR, Transformer remanufacture and thermal modelling of Transformers.
New exit points and Grid sites will allow better interconnection and thus the ability to transfer load if needed.

Table 15: 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 current, 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 significant to maintain a broadly constant level of network risk as measured by the LI metric. A number of 132/33kV grid substations have firm capacity limited by the rating of the switchgear.

Historically, switchgear replacement was the consequence of EHV transformer reinforcement. On the other hand, as load growth remained stable over the recent years, a different intervention driver became predominant.

The East Anglia region has been identified as a prime area for the development of renewable generation due to the significant number of connection requests (Appendix Section 4.6). Distributed generation is expected to lead towards an increase in fault levels on the EHV network and to cause the design limit of the network equipment to which it is connected to be exceeded. As wind and solar farms usually connect at 33kV voltage levels, mitigating actions can be taken by splitting the 33kV network. On the other hand, this has the undesired effect of decreasing network resilience and potentially increasing the number of customer interruptions following a fault.

ED1 forecast

A £58.1M provision for EHV switchgear reinforcement is forecasted for ED1 which represents a decrease of £1.7M when compared to a DPCR5 8 year equivalent. Table 16 provides an overview of the ED1 forecasted expenditure by NAMP line.

NAMP Line	DPCR5 £k (8 years)	ED1 £k	RIGs Code/Line
1.36	59,765	58,026	CV101 11 CV101 15 CV101 18 CV101 22 CV101 40-43 CV101 113 CV101 117-119

Table 16 (source Table J less indirects from 19th February 2014 NAMP Baseline)

This decrease is due to the higher penetration of distributed generation in ED1 compared with DPCR5 at 132kV and EHV level offset by lower High Value Projects.

There has been an increase in generation activity in the last few years, particularly for connection to the 33kV network, which has contributed to the increase in fault level at grid substations to values close to or exceeding the design limit of the equipment to which it is connected.

Currently distributed generators account for approximately 50% of current EPN maximum demand. 2013 has seen over 2000 generation referrals in EPN equating to over 22,159 MW of generation capacity.

This take up of DG is seeing some parts of the network saturated and unable to accommodate new connections of DG. See the Figure 7 below; where the purple and red areas indicate levels of network saturation and the circle refers to a detailed case study on distributed generation (see Appendix Section 4.6)

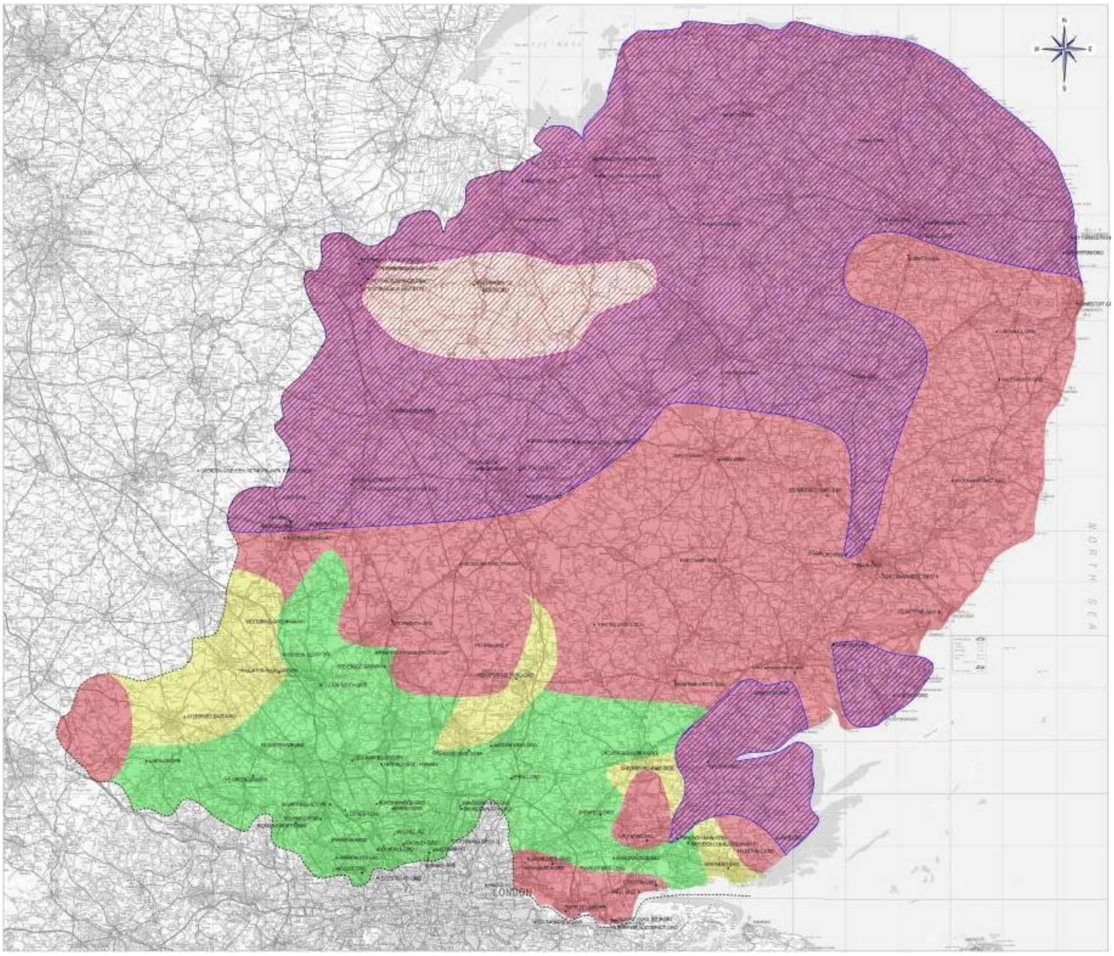

Figure 7: EPN Generation Capacity Map.

Table 17 provides contains further details of the EHV reinforcement switchgear schemes, further information can be found in the gate A scheme papers and the regional development plans.

Type	Project ID	Description	ED1 £k
1.36	2240	Horningsea T/Fulbourn - Reinforce 132kV Capacity	9,959
1.36	3501	Stowmarket 132/33kV Grid Substation - New 132kV Switchboard Reinforcement (N-2)	17,323
1.36	3585	Bramford 132kV GSP Exit Point - Reinforce 132kV Switchgear (Fault Level)	13,114
1.36	2141	Belchamp 132/33kV Grid Substation - Replace 33kV Switchboard (Fault Level)	1,798
1.36	2169	Burwell 132/33kV Grid Substation - Replace 33kV Switchboard (Fault Level)	1,749
1.36	2818	Braintree GSP 132/33kV Exit Point - Replace 33kV Switchboard (Fault Level)	1,646
1.36	3956	Little Barford 132/33kV Grid Substation - Replace 33kV Switchboard (Fault Level)	1,700
1.36	4325	Eriswell Proposed 33kV Switching Station	1,802
1.36	5010	Thorpe 132/33kV Grid Substation - Replace 33kV Switchgear (Fault Level)	1,490
1.36	5698	Huntingdon 132/33kV Grid Substation - Replace 33kV Switchboard (Fault Level)	1,652
1.36	6342	Fulbourn 132/33kV Grid Substation - Replace 33kV Switchboard (Fault Level)	1,896

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

Table 18 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 new generation connected to the transmission network such as large scale offshore wind farms, CCGT and Nuclear Power Plants
Impact of transmission network reinforcement and changes to the 400/275kV network topology
Opportunities
Removal of high HI plant
DSR and in-situ uprating
Increase capacity and fault level headroom to connect further distributed generation

Provision of remote control facilities to the EHV network
Use of fault current limiters to mitigate the fault current to within the switchgear and associated equipment and structure rating
Enabling the use of algorithmic automation for fast acting reconfiguration of the network following faults or to accommodate variable daily demand and generation profiles

Table 18: 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 overhead line or underground circuits with higher rated assets. These are able to withstand higher demand, 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.

ED1 forecast

A £57.8M provision for EHV circuit reinforcement is forecasted for ED1 which represents a £1.9M increase when compared to a DPCR5 8 year equivalent.

Table 19 provides an overview of the ED1 forecasted expenditure by NAMP line.

DPCR5 £k (8 years)	ED1 £k	NAMP Line	RIGs Code/Line
55,825	57,763	1.37	CV101 10 Cv101 17 CV101 40-43

Table 19 (source Table J less indirects from 19th February 2014 NAMP Baseline)

The change is due to the revised levels of reinforcement identified for ED1. EHV circuits have to contend with a combination of complicated load flows between demand and generation customers. In addition to that, we see a number of our circuits reaching their maximum due to construction issues. For instance, the towers supporting our overhead lines can only support conductors with a specific loading. Anything above that threshold would cause issues to the towers foundation.

This reinforcement category also caters for the provision for innovative interventions to increase the rating of an OHL such as allowing for higher temperature of the conductors or dynamic line ratings. Which is likely to reduce the potential costs against the more traditional methods of reinforcement

Table 20 provides further details of the EHV reinforcement switchgear, further information can be found in the gate A scheme papers and the regional development plans. The interventions listed are for the schemes over £1M.

Type	Project ID	Description	ED1 £k
1.37	2234	Horningsea T/Arbury/Histon 132kV OHL (PTK/PMK) Circuits - Reinforce (925A(W))	6,774
1.37	5848	Lawford - Cliff Quay 3 & Ipswich 1 PEC Route Reinforcement	2,980
1.37	3924	March Grid/Chatteris Primary 33kV Circuits - Rebuild (575A)	1,228
1.37	2716	Parker Avenue 132/33kV Grid Substation - Install Grid Transformers (2 x 90MVA) and 132kV Circuits	15,443
1.37	3614	Eaton Socon / Little Barford 132kV Circuit Reconfiguration	13,319
1.37	3570	Hornchurch/Cranham Proposed 33kV Interconnection (N-2)	1,552
1.37	3800	Rayleigh Local/Uplands Park 33kV FFC Circuits - Reinforce Circuits (600A)	1,120
1.37	5006	Lt. Barford/Sandy 33kV OHL Circuits - 3rd U/G Circuit	2,356
1.37	5779	Earlham Grid/Wymondham 33kV Circuit - Phase 2 Reinforcement (770A(W))	2,010
1.37	6186	Finchley 132/33kV Grid Substation - Load Transfer (Transfer Bellevue Primary to Hendon Grid)	1,828
1.37	3986	(RDP - Braintree) Lawford/Rayleigh 132kV Circuits (PNB, PUD, PAE) - Reinforce	1,453
1.37	4069	Rye House/Harlow West 132kV Tower Line (PDE/PCK) - Separate 132kV Circuits (N-2)	5,396

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

Table 21 illustrates the additional risks and opportunities that could materially affect the forecast.

Risks
An upturn in economic activity could increase load.
True load is masked by embedded generation at all levels.

Health data is incomplete (e.g. previous fault history, location and lengths of replacements not recorded).
Significant increase in costs due to wayleave re-negotiation
Opportunities
Removal of high HI plant
DLR and DSR
Better line profiling and condition assessment methods like LIDAR scan, high resolution photography and hot spot measurements.
Different methods to increase the rating of an OHL such as allowing for a higher temperature, seasonal ratings or active measurements
Use of reliable dynamic rating techniques to allow maximum utilization of available capacity.
Interconnection across historic boundaries will increase resilience.
Uprating for reinforcement may assist in the reduction of faults

Table 21: 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 transformer replacement, 11kV switchgear replacement as well as other minor projects such as CT replacement, 11kV transformer tail replacement, and additional transformer cooling.

Primary reinforcement is required to maintain P2/6 compliance, protect plant from damaging overloads, prevent large scale loss of customers (CI's), enable rapid restoration following an unplanned outage (CML's) and manage fault levels. Resolving primary substations overload, as measured by the LI metric, is therefore key to achieve our strategy of maintaining the network risk broadly constant.

Historical maximum demand and forecasting tools are used to identify the substations requiring interventions. The projects flagged go through a rigorous process which includes reviewing forecasted demand, confirming network capacities and establishing a range of options before commitment is made to a final solution.

ED1 forecast

Our ED1 forecast for HV primary substation reinforcement is £69.2M and is £9.2M higher than DPCR5 spend (on an 8-year basis). Table 22 provides an overview of the ED1 forecasted expenditure by NAMP line

DPCR5 £k (8 years)	ED1 £k	NAMP Line	RIGs Code/Line
60,026	69,238	1.33	CV101 8-10 CV101 13 CV101 16-17 CV101 20 CV101 63

Table 22 (source Table J less indirects from 19th February 2014 NAMP Baseline)

As previously explained, as a result of the lower load growth rate expected for most of ED1, we reduced the forecasted expenditure to provide capacity on 132kV and 33kV substations and shifted the incremental steps in load growth to our lower voltage network

On the other hand, we are expecting areas within our networks to experience significant load growth. For instance, the 2011 Census showed the rate of population in East of England being the fastest in the country at 8% (vs. the national average of 7%). In addition to that, specific areas within our network (e.g. Cambridge) are establishing themselves as leading IT/science clusters in the country with the consequence that this brings in terms of load growth which will include a number of data centres

This diversity that occurs through the different voltages in a distribution network, i.e. stable overall maximum demand vs. localised high growth, leads to an increase in spending in the HV / LV network. That is load applied at 11kV has a greater impact at that level than it will at higher voltage as the maximum demand profile of each individual customer is averaged across a smaller number of connections leading to spikier profiles when compared to EHV maximum demand profiles.

Table 23 provides further details of the HV primary substation reinforcement, further information can be found in the gate A papers and regional development plans, The interventions listed are for the schemes over £1M

Type	Project ID	Description	ED1 £k
1.33	2451	Cockfosters 33/11kV Primary Substation - ITC T1 (1x 20/30/40MVA) & 11kV Switchgear	1,502
1.33	3560	Wisbech Railway 33/11kV Primary Substation - ITC (2 x 18/30/40MVA) and 11kV Switchgear	2,061
1.33	4173	Upwell (Lakes End) 33/11kV Primary Substation - ITC (2 x 7/11/15MVA)	1,399
1.33	4271	Tilney Proposed 33/11kV Primary Substation – New Substation (1 x 7/11/18MVA)	1,525
1.33	4291	Reed 33/11kV Primary Substation - ITC (1 x 7.5/15MVA & 1 x 11/18/24MVA)	2,771

1.33	4306	South Stevenage 33/11kV Primary Substation - ITC (3rd 18/30/40MVA), Extend 11kV Switchboard and New 33kV Circuit	3,068
1.33	4406	East Letchworth 33/11kV Primary Substation - ITC (2 x 18/30/40MVA) & Switchboard (2000A)	1,580
1.33	4408	Manton Lane 33/11kV Primary Substation - ITC (2 x 18/30/40) & Switchboard	1,690
1.33	5397	Highfield 33/11kV Primary Substation - ITC (2x18/30/40MVA), 11kV Switchgear and 33kV Circuits	3,809
1.33	5399	Ladysmith Rd 33/11kV Primary Substation - ITC (2 x 18/30/40MVA), 11kV Switchgear and 33kV Cables	2,968
1.33	5402	Merryhill 33/11kV Primary Substation - ITC (2 x 20/30/40MVA) & 11kV Switchgear	1,921
1.33	5408	East Finchley 33/11kV Primary Substation - ITC (2x 20/30/40MVA) and 11kV Switchboard	2,042
1.33	5409	Greenhill 33/11kV Primary Substation - ITC (18/30/40MVA), Switchgear and Cables	1,910
1.33	5566	St Anthony Steet 33/11kV Primary Substation - ITC (2 x 18/30/40MVA) and 11kV Switchboard	2,025
1.33	5609	East Hertford 33/11kV Primary Substation - ITC (2 x 11/18/24MVA)	1,142
1.33	5724	Hapton 33/11kV Primary Substation - ITC (2x11/18/24 MVA)	1,298
1.33	5729	Thaxted Local Primary 11kV Reinforcement	1,098
1.33	5730	Fairstead 33/11kV Primary - ITC (2 x 18/25.4/40 MVA)	1,326
1.33	5812	North Drive 33/11kV Primary Substation - ITC (2x 12/18/24MVA) & Switchgear	1,123
1.33	6092	Chelmsford East Local 33/11kV Primary Substation - ITC (2x 11/18/24MVA)	1,142
1.33	6191	Brockenhurst/Mil Hill 33/11kV Primary Substations - ITC (2 x 12/18/24MVA) and 11kV Network Reinforcement	1,479
1.33	6201	Berkhamstead 33/11kV Primary Substation - ITC (2 x 20/30/40MVA), 11kV Switchgear and 33kV Circuits	4,923
1.33	8183	Godmanchester 33/11kV Primary Substation - ITC (2x12/24MVA)	1,711
1.33	5602	Bellhouse Lane 33/11kV Primary Substation - ITC (2 x 12/18/24MVA) and 11kV Switchboard	2,361
1.33	6197	Hornsey Grid 132/11kV Substation - 11kV Switchgear (2000A Double Bus)	1,545
1.33	2053	Romford - General Primary Substation Reinforcement.	2,276
1.33	3684	Maldon/South Woodham - Proposed New Primary Substation (Temp Name - Purleigh Primary)	2,606
1.33	3850	Mucking Creek Proposed 33/11kV Primary Substation - (2 x 18/30/40MVA)	2,064
1.33	4009	Icknield Way Proposed 33kV Switching Station	2,792
1.33	4091	March Grid Proposed Local 33/11kV Primary Substation - (1 x 11/18/24MVA)	1,632
1.33	4272	Red Lodge Proposed 33/11kV S/S (RDP*) - (2 x 11/18/24MVA)	6,102

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

This reinforcement expenditure category also includes £1M of demand side response measures to mitigate the need for reinforcing the network at a Primary substation level, thus providing value for money to our customers. Projects in this category include:

- Whittlesey 33/11kV Primary Substation - (DSR)
- Kempstone 33/11kV Primary Substation - (DSR)
- Brandon End 33/11kV Primary Substation - (DSR)
- Eye 33/11kV Primary Substation - (DSR)
- BEE 33/11kV Primary Substation - (DSR)
- Orton 33/11kV Primary Substation - (DSR)
- Caister 33/11kV Primary Substation – (DSR)

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

Risks
An upturn in economic activity could increase load and utilisation.
Further migration of night time load.
Increased use of direct acting heating in new build homes affecting winter peak demands.
Air Conditioning penetration increasing summer peak demand.
Small embedded generators inability to withstand disturbances on the distribution system.
Lack of visibility of embedded generation at HV and LV masks true demand that would be present following a network interruption.
Supply Companies pricing signals shifting the demand peak to times moving time of day loads.
Opportunities
Removal of high HI plant
Supply Companies pricing signals moving time of day loads if co-ordinated with LNO.
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 customer
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 24: Risks and Opportunities potentially affecting the forecast

3.4.5 HV Reinforcement and Load Transfers

Investment drivers

HV reinforcement and load transfers include replacement of overhead lines, 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 for HV reinforcement and Load Transfer is £34.3M and is £9.8M higher than DPCR5 spend (on an 8-year basis). Table 25 provides an overview of the ED1 forecasted expenditure by NAMP line

DPCR5 (8 year equivalent) £k	ED1 £k	NAMP Line	RIGs Code/Line
24,483	34,290	1.34	CV101 7-8 CV101 10 CV101 16 CV101 31-32 CV101 51

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

This increase is associated with interventions to facilitate the transfer of demand across the 11kV network or to provide additional capacity (e.g. transformers) that will accommodate the incremental steps in load growth. This strategy will enable us to defer more costly Primary Substation reinforcements at EHV voltage level.

Therefore we are forecasting to increase the number of HV reinforcement schemes (from 312 to 817) and the kilometres of circuits reinforced (from 172 to 470). The total cost of circuit reinforcement and interconnection schemes to improve our load transfer capability accounts for £23.5m of out of the £34,290m forecasted expenditure.

This figure is based on historical volumes and load growth in specific areas of the network. It also includes the following named schemes:

- Belchamp / Sudbury 11kV modification (£558k);
- Kimbolton 33/11kV increase interconnection (£837k);

Load transfer schemes already identified within the EPN area account for £3.9m of ED1 forecasted NAMP expenditure and include:

- Transfer from Kingsbury 33/11kV to Kenton Primary;
- Transfer from Frogmore 33/11kV to Warners End;
- Transfer from Leigh 33/11kV to Hadleigh Road and Bellhouse Ln;
- Transfer from Hainault Ave Primary to Fleethall Local;
- Transfer from Canvey to South Benfleet Local Primary;
- Transfer from Lakeside Primary to Barclay Way;

Please refer to the individual Regional Development Plans for further details.

In addition to that, we expect to see an increase in overloaded transformers as the HV network is increasingly more utilised hence the increase in expenditure in ED1 (£1.6m).

Table 26 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.
Potential to remove FFC cables.
Improve network functionality.
Address ESQC issues with Overhead lines.
Enabling the use of algorithmic automation for fast reconfiguration of the HV network following faults, to accommodate variable demand/generation profiles and manage the load at the Primary substation
Increase interconnection at 11kV between primary substations improves network resilience;

Table 26: 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 a LV reinforcement element within our Imperial College LRE model. Please refer to Appendix Section 4.7 for more details.

ED1 forecast

Our ED1 forecast for LV reinforcement schemes is £ 34.4M and is £21.2 M higher than DPCR5 spend (on an 8-year basis). Table 27 provides an overview of the ED1 forecasted expenditure by NAMP line.

DPCR5 (8 year equivalent) £k	ED1 £k	NAMP Line	RIGs Code/Line
13,184	**34,358**	**1.39**	**CV101 6-7 CV101 29-30 CV101 50**

Table 27 (source Table J less indirects from 19th 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.

The increase in expenditure during the ED1 relates to an increase in LV reinforcement schemes volumes (from 259 to 744) and kilometres of circuits reinforced (from 181 to 308), and a potential increase in voltage regulation schemes.

As explained in the previous section, the forecast takes into account the modelled impact of the introduction of smart metering, electric vehicles (EV), PV, small scale generation and heat pump penetration (HP) which will have a significant impact on the capability of our LV network.

As an illustrative example of the peak demand rate of growth expected to occur on the network, Figure 8 illustrates the forecasted HP and EV peak demand in the EPN area.

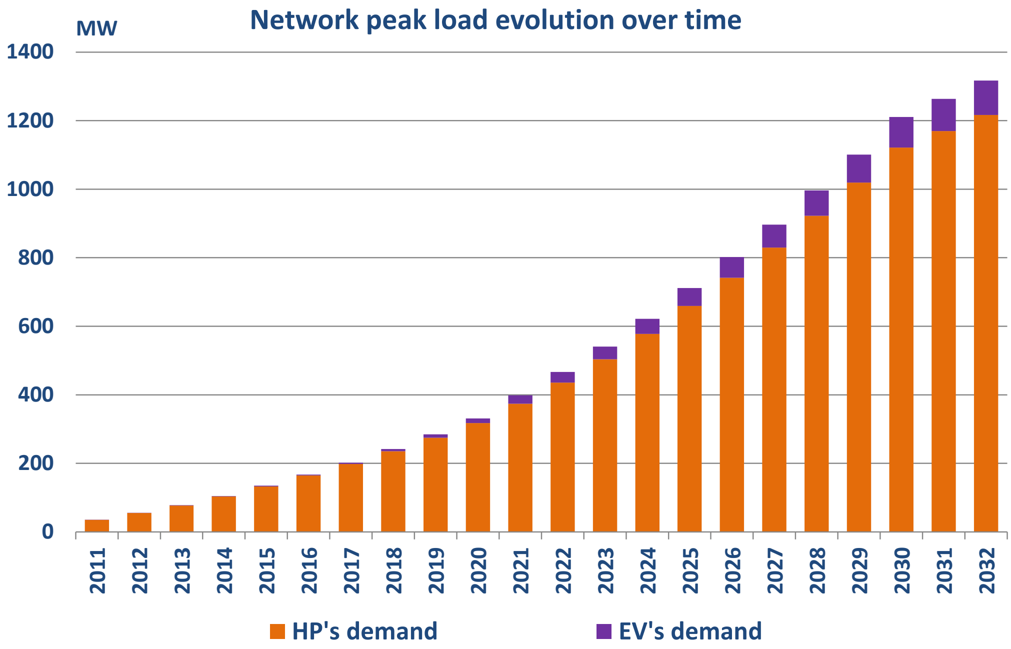

Figure 8: Forecasted HP and EV peak demand in EPN Area.

Based on these assumptions, the Imperial College LRE model provides an indication of the volume of work that may be expected based on the Core Scenario load growth and the other DECC scenarios. Figure 9 illustrates the modelled output and our forecast expenditure.

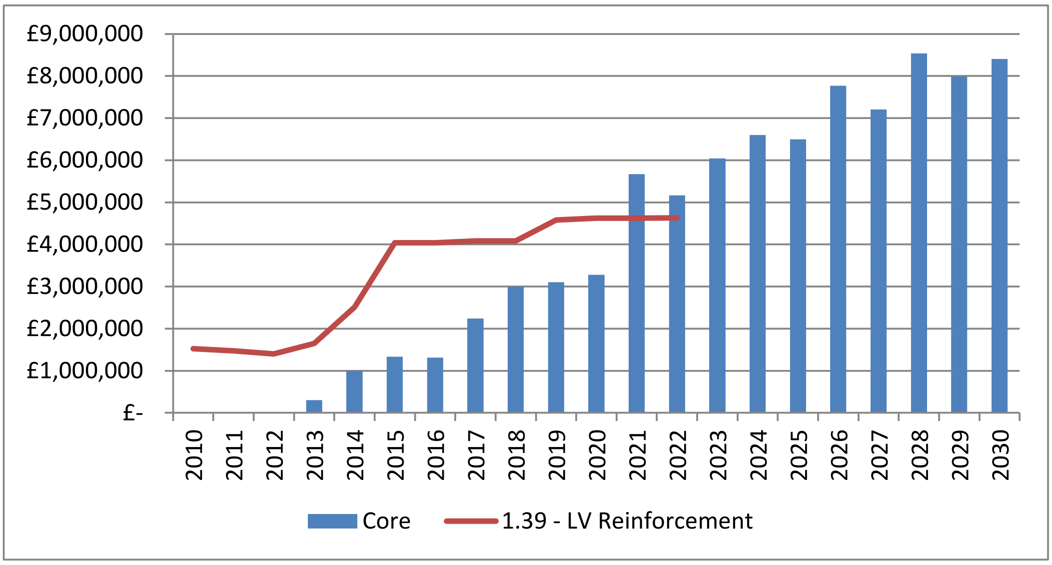

Figure 9: Modelled output and forecast expenditure

We would expect our forecast for planned work to typically be above the model output in the short term, as there are effects that are not modelled. This includes drivers of investment in the LV networks such as latent work that is expected to be revealed through the implementation of smart meters (from 2015 onwards) and sensors at feeder level.

The results of our models and the need to increase expenditure on LV reinforcements are substantiated by trend of customer complaints relating to statutory voltage in the EPN area as shown in Figure 10.

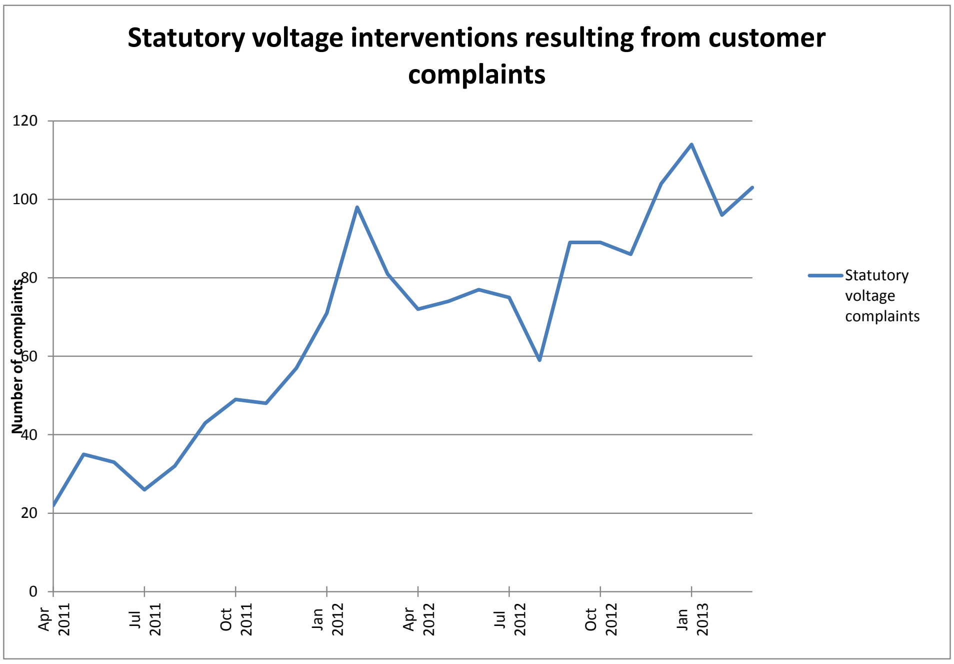

Figure 10: Trend of Customer complaints relating to statutory voltage.

Table 28 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 data quality and accuracy unlocks additional opportunities for non-conventional responses
Photovoltaics offsetting demand

Demand side response

Table 28: Risks and Opportunities potentially affecting the forecast

3.5 High Value Projects

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

There is one project belonging to this category. It is split into three parts to reflect the correct NAMP lines for allocation of costs.

1.35.05.5619 Eaton Socon, Exit point 3rd SGT

1.37.06.3614 Eaton Socon circuit reconfiguration

1.48.08.5593 Replace Switchboard

Full details of this scheme can be found in the gate A 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 case 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 significantly 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 had 80 sites and schemes that we identified 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.

The list below shows major schemes where we are investing less than we forecasted in the DPCR5 plans by more than £5m:

- Parker Avenue 132/33kV Grid S/S - install grid transformers and 132kV circuits (2x90MVA). There has been no firm commitment for a new connection therefore the project has been deferred with the exception of legal agreements for the cable routes;

- Reinforcement of the Lawford/Rayleigh 132kV double Circuit - a review of the regional strategy has identified an alternative reinforcement to maintain P2/6 compliance and operational flexibility particularly during planned outages which requires the re-conductoring of the PJ and PEC 132kV overhead lines between Lawford and Bramford/Cliff Quay with 300UPAS to replace the existing 175mm (Lynx) conductors;

- Eaton Socon 132kV GSP - 3rd SGTand new 132kV GIS - delayed in order to review asset condition and consider wider network operation;
- Proposed Marston 132/33kV Grid S/S - 2 x 90MVA – project completed with savings;
- Leighton Buzzard 33/11kV Primary S/S - reinforcement (3 x 18/30MVA) – delayed as innovative solutions such as High Temperature Low Sag conductors and storage devices are being installed;
- Belchamp 132/33kV Grid S/S - transfer to Bramford (RDP*) – slowed down due to economic conditions;
- Chelmsford North 132/33kV Grid S/S - Reinforcement (1 x 90MVA) - Alternative scheme proposed (load transfer scheme) to reinforce 33kV network.

The list below shows major schemes where we are planning to invest more than allowed:

- Clacton 132/33kV Grid S/S – increase 33kV switchgear rating – due to an increase in scope of work to cater for asset health issues

Overall for our EPN network we will out-deliver our LI outputs for load while delivering a saving against our capital expenditure allowance for DPCR5 of approximately 39% or £147.m.

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' EPN Network

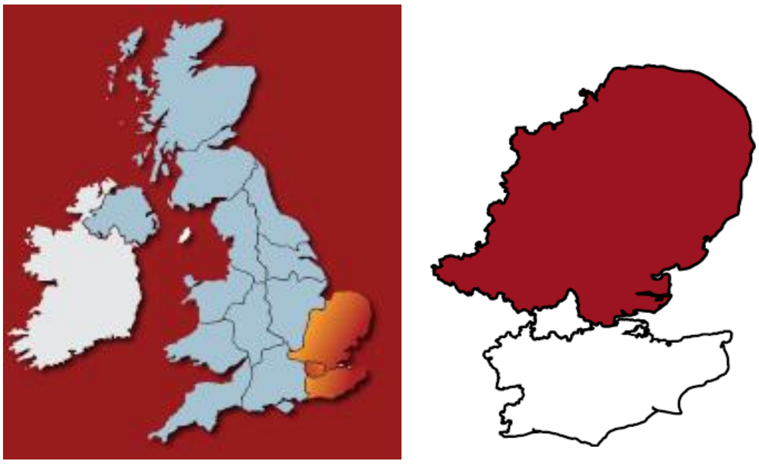

Figure 11: EPN Geographic Area

Eastern Power Networks plc's distribution network supplies electricity over an area of approximately 20,300 square kilometres, incorporating all of the counties of Norfolk, Suffolk and Hertfordshire, most of Cambridgeshire, Essex and Bedfordshire, parts of Buckinghamshire and Oxfordshire, and the northern suburbs of Greater London, as shown in Figure 11.

The network can be considered as relatively mature and stable power system, supplying the needs of over 3.5 million customers, at a peak maximum demand for the 2012/13 year of 6,605 MW. The network has developed predominantly from early power sources in the 1930's through to rural electrification in the 1950's. This in turn was followed by transmission system construction and a period of rapid development (including, for example, the development of new towns such as Hemel Hempstead and Welwyn Garden City under the New Towns Commission) in the 1960's.

Electricity is taken from National Grid's 400kV and 275kV networks at a number of 'Supergrid' sites and distributed to our customers through a succession of networks operating at various voltages ranging from 132kV down to 400/230V.

EPN comprises predominantly 132kV and 33kV voltage levels. The EHV System is characterised as a distribution network with a mixture of radial 132kV transformer feeders and circuits interconnecting 400kV and 275kV super-grid connection points, some of which are run 'solid'.

Figure 12: Grid Supply Points

The EPN 132kV network takes bulk power from National Grid at 132kV Grid Supply Points (GSP's). The diagram above (figure 12) identifies the National Grid's connection points within the EPN Network area. There are six transfer points within the EPN Network interconnecting with other Distribution Network Operators.

The EPN EHV System consists of a mixture of 33kV overhead lines and underground cables. The overhead lines consist of 3,478km of 33kV single circuit overhead line, with wood or concrete poles or steel structures. Most of the structures were erected between 1955 and 1978, although construction continued to 1995. The EHV cable comprises a total length of 17,348km of 33kV cables, of which 16,717km are non-pressurised cable, mostly installed from 1945, and 631km are pressurised cable installed from 1962 onwards. There are 487 primary substations, which operate at EHV (33kV), taking supply from the 33kV network.

The EPN HV System consists of a mixture of 11kV or 6.6kV overhead lines and underground cables. The EPN HV (6.6kV and 11kV) overhead lines have a total circuit length of 19,320km, erected between 1955 and 1995. Total lengths of 18,999km of 6.6kV and 11kV underground cables have been mostly installed between 1955 and 2005. There are 69,528 EPN HV substations, operating at 6.6kV and 11kV of which 53% are pole mounted and 47% ground mounted. The HV distribution substations take supply from primary substations and transform to LV or supply directly to customers across the EPN Area.

The EPN LV System circuits comprise a mixture of 230/400V overhead lines and underground cables. LV OHL mains comprise 9,299km of open wire and Aerial Bundled Conductor (ABC) construction, installed between 1950 and 1990. The LV underground cables comprise of a total length of 39,072km, of which 67% are Paper Insulated Lead covered (PILC) and the remaining 33% are plastic/waveform and less than 1% Consac cable. PILC was installed from 1920 up to the early 1970's, after which polymeric cable took over.

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 13 below:

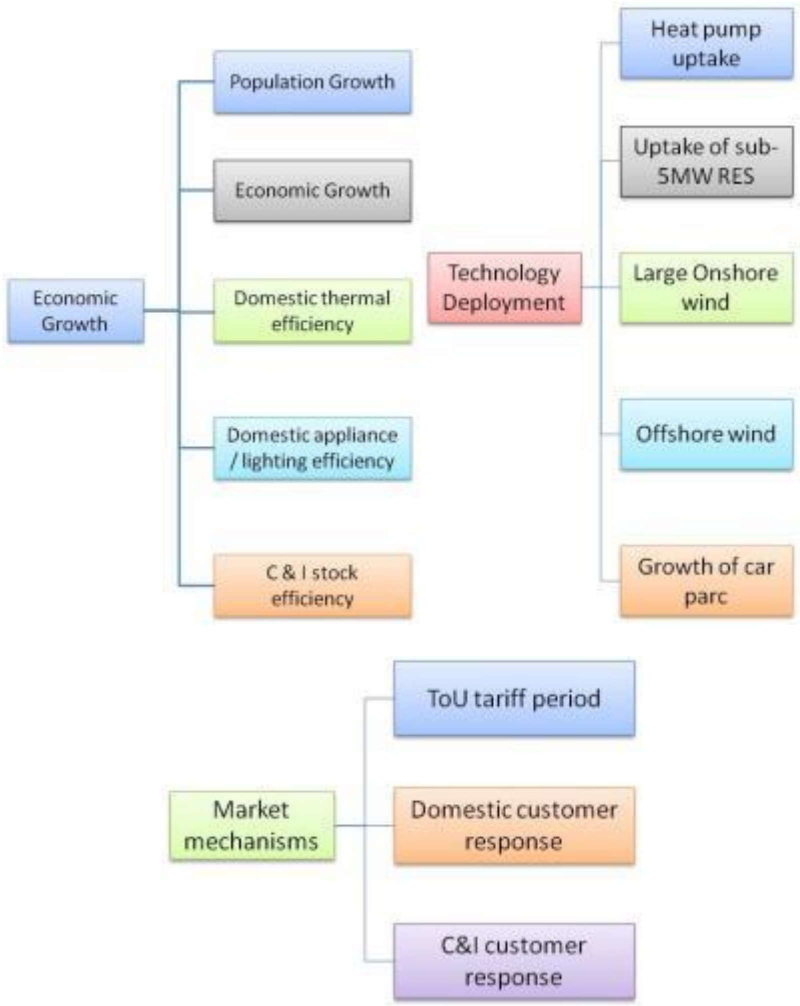

Figure 13: Key planning inputs

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 29 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 take up 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 take up	• Element Energy analysis of take up rates based on various market conditions
• Growth of car parc	• Based on Department of Transport TEMPRO analysis

Table 29: 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 30. 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 30: 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 have not changed our core population and economic growth assumptions for our July 2012 Business Plan submission. However, since the July submission, changes have been made. We continue to believe that utilising long run average data provides the best basis for forecasting future population and economic growth.

Table 31 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 31: Government forecasts for new household formation

Table 31 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.

Table 32 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 therefore assumed that the yearly level of household formation, over the ED1 period, is equal to the historic long run average shown in Table 32 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 and the practical issues associated with delivering significant increases in house building in the South East.

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

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

Table 32: Average annual increase in household formation

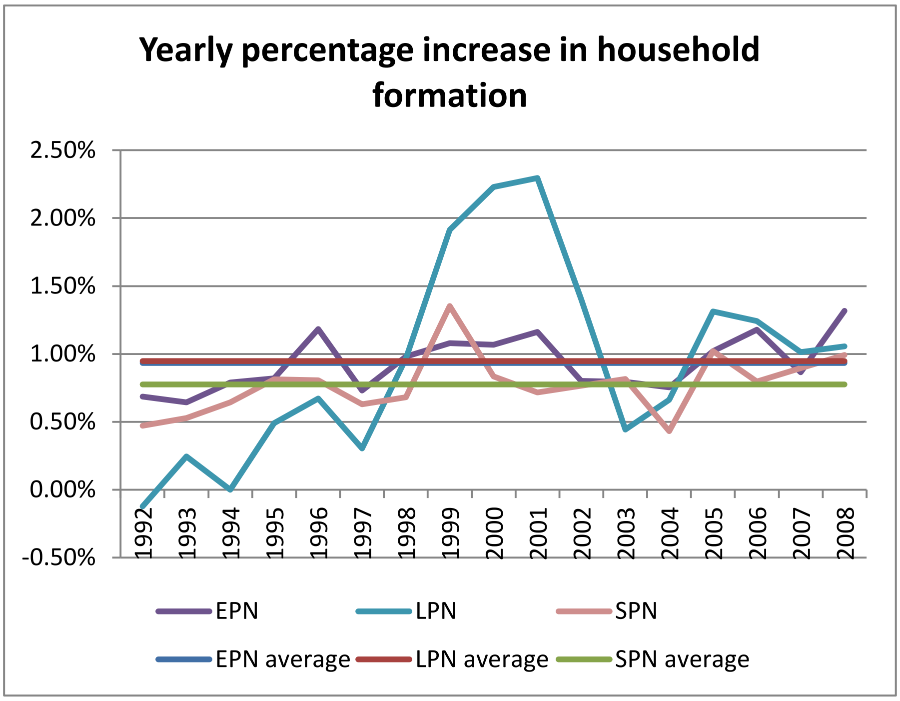

Figure 14: Yearly percentage increase in household formation

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 15 details the year on year growth over the period in nominal terms.

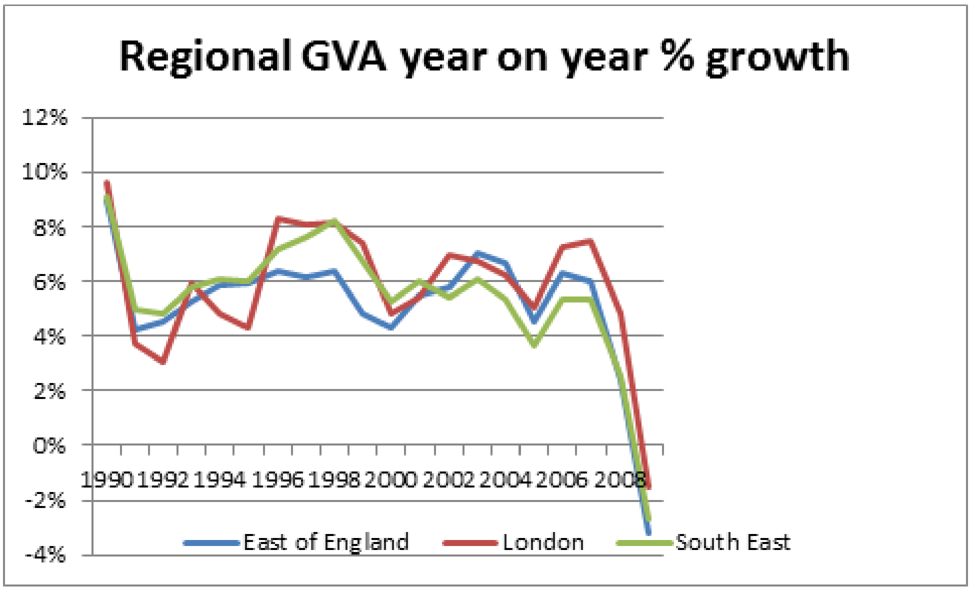

Figure 15: Regional Growth over the period

The values used are shown in Table 33 below:

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

Table 33: Annual Forecast increase in regional GVA

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 July 2012 submission. 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 and SPN but reduce in 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 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 (34-36) 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 34

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 35

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 36

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 July 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 takes 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 37:

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 – credit purchase	Reflects a future where more than one key technology under-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 37: 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

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 Figure 16 below, which includes a view of the maximum peak load over time:

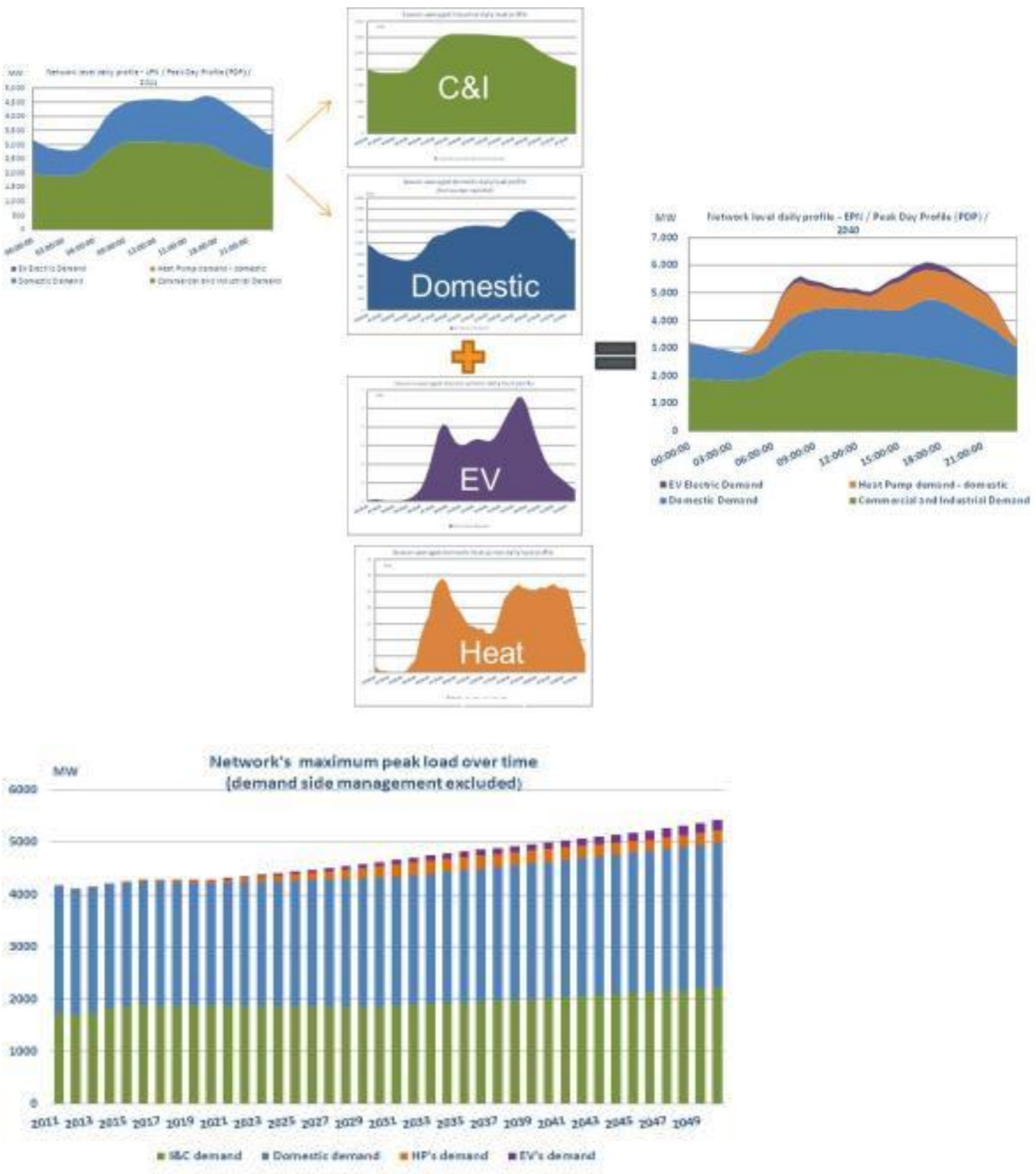

Figure 16: Pictorial view of demand and network peak load evolution over time.

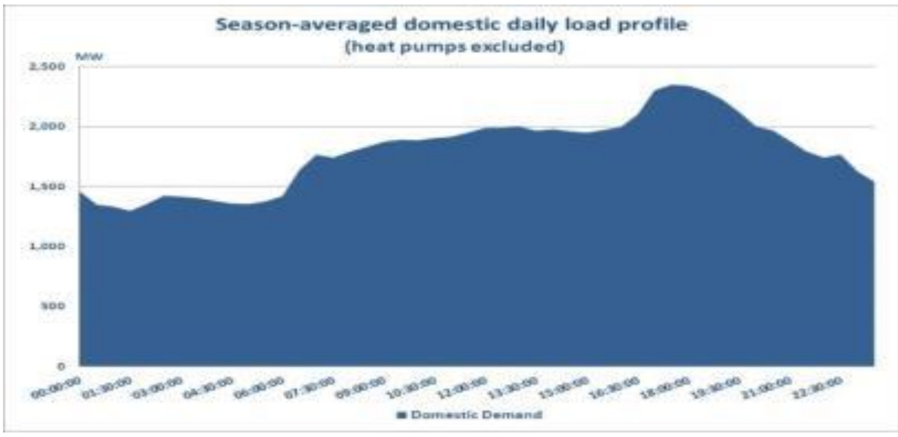

Figure 17: Output of the Model

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 shorter-term 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 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.

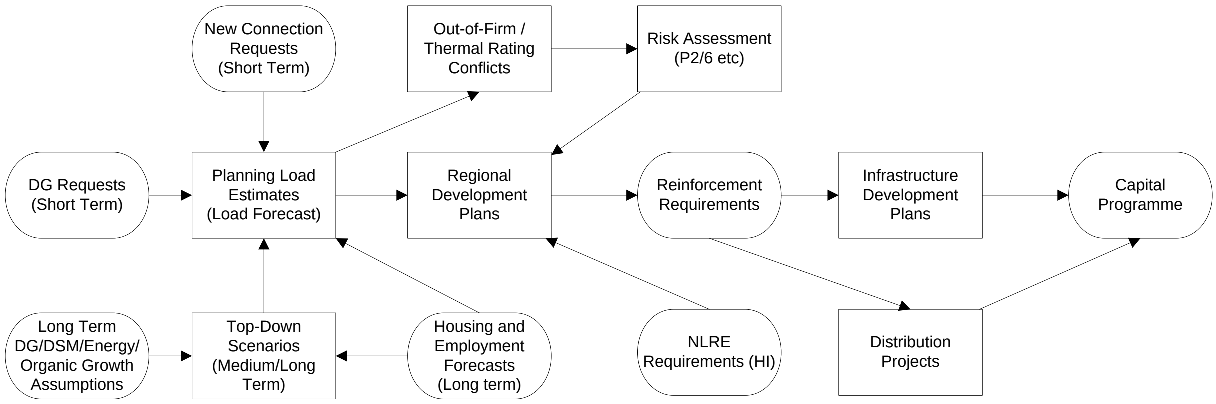

Figure 18: Process Flow Diagram

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 EPN there are 20 Regional Development Programmes as shown in Figure 19 below. Please note that RDPs 3 and 4 have been merged.

RDP01	Walpole GSP
RDP02	Walpole GSP - Peterborough
RDP03	Norwich GSP
RDP04	Norwich City
RDP05	Burwell GSP
RDP06	Eaton Socon GSP
RDP07	Sundon & Amersham GSP
RDP08	Pelham & Wymondley Group
RDP09	Bramford GSP - West
RDP10	Bramford GSP - East
RDP11	Bramford GSP - Ipswich - Cliff Quay
RDP12	Bramford GSP - Coast
RDP13	Elstree & Rye House GSP
RDP14	Elstree & Watford South Group
RDP15	Elstree & Mill Hill & Willesden GSP
RDP16	Brimsdown & Tottenham GSP
RDP17	Rayleigh & Braintree Group
RDP18	Rayleigh & Bramford Group
RDP19	Rayleigh & Tilbury Group
RDP20	Warley & Barking & West Thurrock GSP

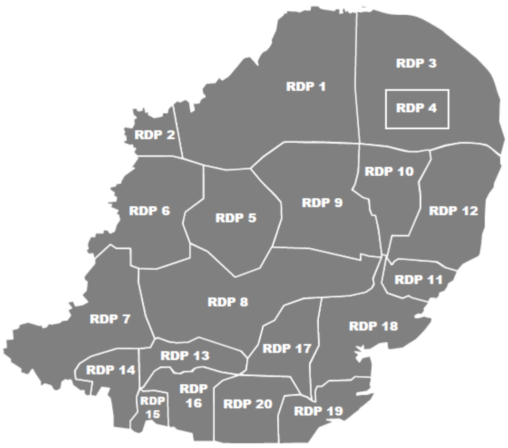

Figure 19: Geographic Areas for the RDP's

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 remaining Operational and Technical constraints

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 38: 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 39: 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 40: 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.

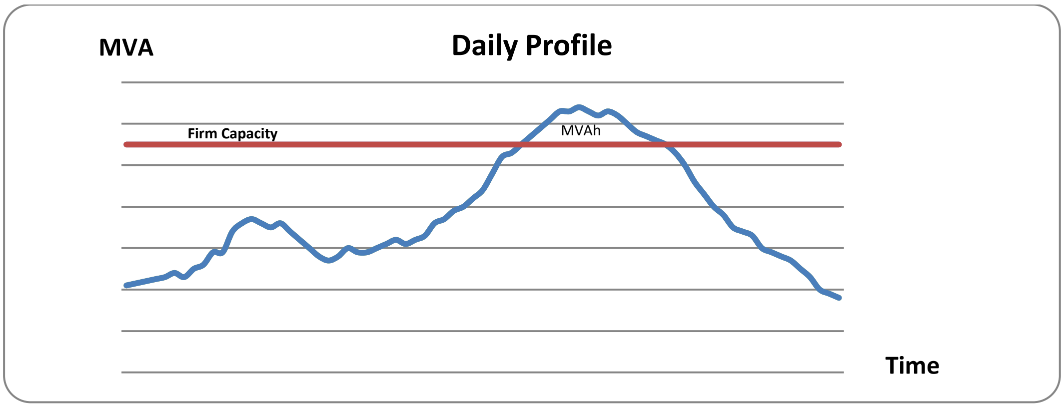

Figure 20: Typical substation load profile showing load at risk

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 41: 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 connection between two sites to allow the load on one site to be supplied from the other. 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.

Substation	NAMP Reference	MVA	Start Year
Kempstone Primary11kV	1.33.01.3328	2.0	2018
Whittlesey Primary 11kV	1.33.01.3900	2.0	2017
Eye Primary 11kV	1.33.01.5396	2.0	2017
Caister Primary 11kV	1.33.01.5733	2.0	2017
BEE (Commercial & Wembley Stadium)	1.33.01.5710	2.0	2018
Orton Primary 11kV	1.33.03.5731	2.0	2021
Brandon Primary 11kV	1.33.01.2128	2.0	2018

Table 42: 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 and the planned installation at Leighton Buzzard in DPCR5 one more site has been identified where this technology is applicable.

Substation	NAMP Reference	MVA	Start Year
Canvey Primary 11kV	1.34.02.6348	4.6	2048

Table 43: EPN Future battery storage interventions

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.

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 ampacity 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.

The following circuits are proposed for DLR in the EPN area:

Circuit	Reference	Addressed Constraint MVA
Bury-Peterborough Central 33 kV	DLR1	5
P49 March Grid Tee Chatteris T2 – Funtham's Lane T2	DLR2	9
P28 March Grid Tee Chatteris T1 – Funthams Lane T1	DLR3	3
P49 March Grid Tee Chatteris T2 – March Grid 33 kV Bus Bar	DLR4	

Table 44: EPN Future DLR interventions

Whilst high conductor temperature can cause of loss of grease, conductor expansion, and hence sag, can cause infringements of minimum clearances. Insulated cross-arms provide a method of raising conductors on existing structure and can produce a less intrusive design for new support structures. This technology of insulated cross arms on the 132 network is in its development and proving stage, once proven it is an ideal solution for ground and building clearance without the need for taller towers.

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 Quad booster has now been commissioned and the benefits from this installation are being evaluated.

4.6 Interventions to support distributed generation

We would expect EPN Networks to take their fair share of the UK's commitment to renewable generation and currently. We are seeing a large potential for new Wind Farms and increasingly solar farms connecting to the Network. Connected generation capacity currently now represents approximately 50% of current EPN maximum demand.

Over forty Grid and Primary substations are experiencing reverse power flow as a result of embedded generation currently connected indicating that local area demand is less than the generation capacity.

2013 has seen over 2000 enquires in EPN equating to over 22,159 MW of generation capacity. These connections range from the low voltage network through to the 132kV system. At present approximately there is 7% take up of these enquiries indicating the speculative nature of this market and multiple applications for the same capacity. This take up of DG is seeing some parts of the network saturated and unable to accommodate new connections of DG. See Figure 21 where the pink areas indicate network saturation.

EPN	**MW**	**Projects**
Gas (CCGT)	1142.0	12
Landfill Gas	297.1	69
Sewage Gas	14.3	12
Off-Shore Wind	582.8	4
On-Shore Wind	299.0	46
Domestic PV (Solar)	146.1	27057
Industrial PV (Solar)	154.3	101
Biomass	102.1	4
Energy From Waste	77.0	2
CHP	357.1	156
Diesel	68.5	57
Other Generation	24.9	12
Standby Diesel & Other Generation	88.8	43
Total	**3354.1**	**27575**

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

Applying traditional methods of connecting DG so as to give a firm connection creates blockers to renewable developments e.g. where small developments need extensive network reinforcements in order to connect to a part of the network with sufficient capacity. These can make a project unviable as a result of when they have come forward. In order to overcome these challenges we are looking at the options and undertaking analysis on the benefits of developing new capacity on an anticipatory basis.

Another approach is to offer a disconnectable connection to provide a more economic and faster connection to constrained parts of the network. A study case “Plug and Play” area, funded by the Low Carbon Networks (LCN) has been established employing smart grid technologies and smart commercial agreements.

The study case is located in Cambridgeshire with an area of 700km² fed by a 33kV and 11kV Network (2 Grid, 10 Primary substation sites) with a 148MW connected wind generation and a further 165MW in the planning and delivery stage.

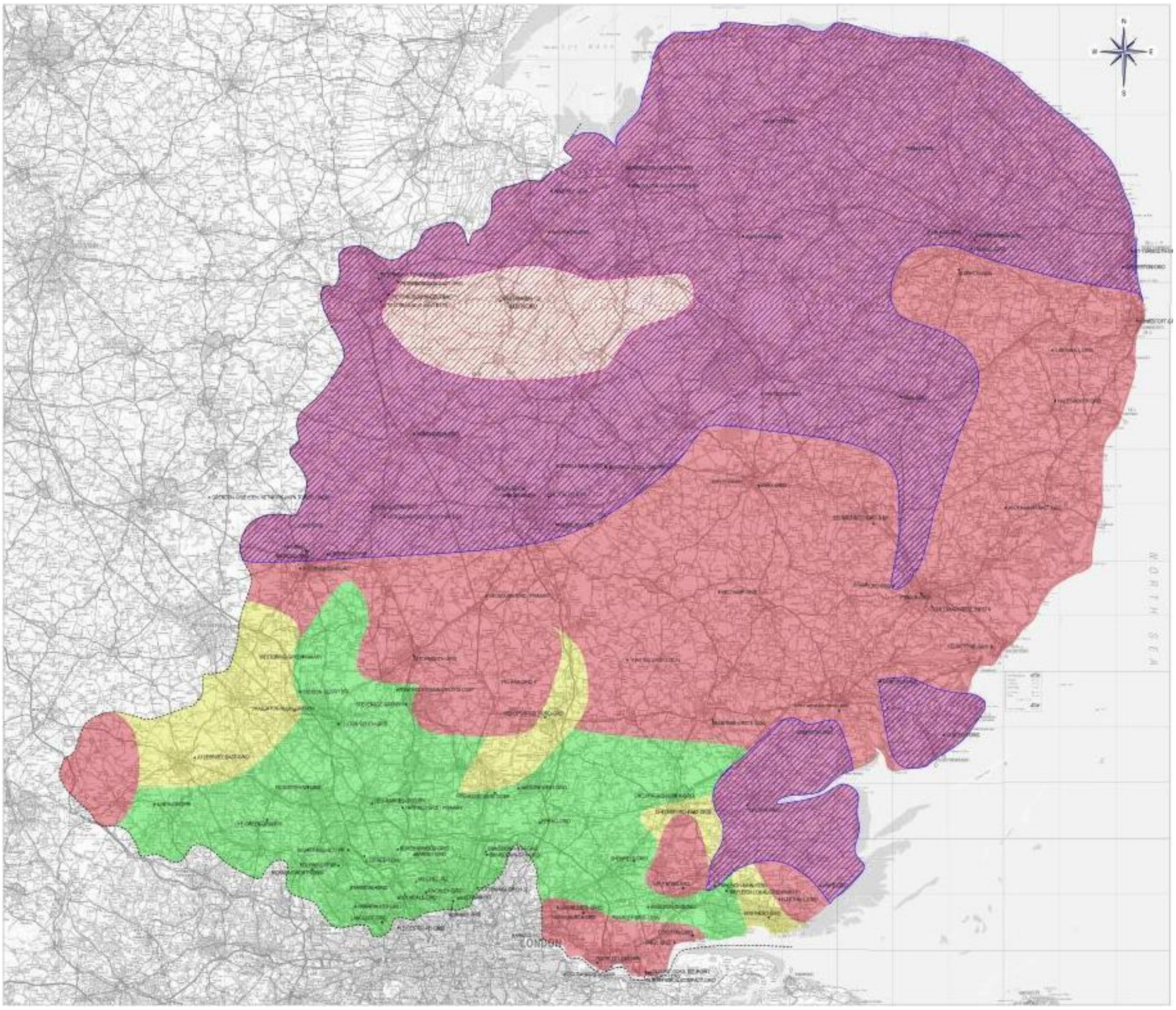

Figure 21: Study Case Area - East Anglian Location Map

There is a sensible limit of how much generation can be connected in this manner and this is related to the ratio of the curtailment costs against the cost of reinforcement, illustrated in the figure below.

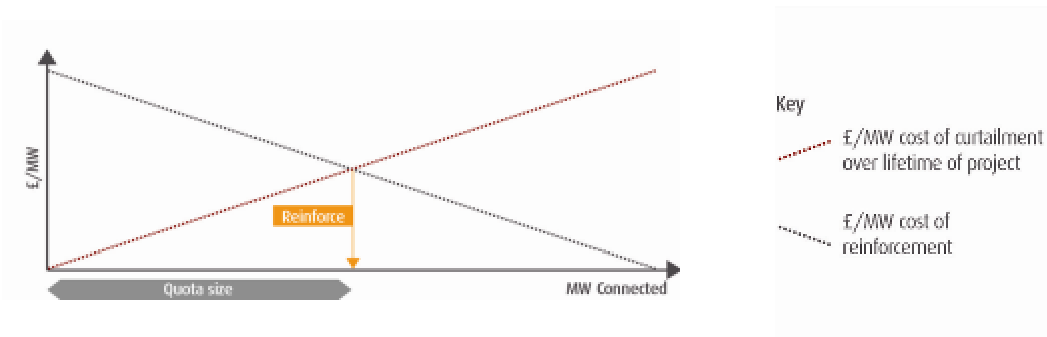

Figure 22: Ratio of Curtailment Cost and Reinforcement Cost

DG infrastructure investment

This project is intended to address existing network constraints in the East of England where there have been a high number of renewable generation developments. While UK Power Networks supports the timely and efficient connection of these medium to large scale generation proponents to its network, it emphasises that significant network investment is required to ensure the maintenance of the quality and reliability of supply and network safety standards for existing customers.

UK Power Networks reviewed 16 investment projects ranging in capacity to be installed between 90MVA and7MVA and has subsequently revised the size of the investment.

Cost-benefit / options analysis – UK Power Networks undertook an internal cost benefit assessment of the different investment options. This assessment involved:

- Determining the cost of each network investment project and assumed that the costs would be incurred in a single year
- Determining the benefits associated with each project, being the reduction in carbon emissions from the connection of low carbon generation enabled by the network extension. UK Power Networks assessed the benefits using both the DECC energy market traded and non-traded carbon values (high-low scenarios in both cases) over a period of 16 and 24 years
- Assuming phased use (over several years) of the additional network investment

Our Business Plan Update proposes four projects should be developed during RIIO-ED1 releasing a further 187MVA of network capacity at a total cost to consumers of £15.35 million including:

- March Grid increase in transformer capacity;
- New Grid substation between March and Peterborough,
- Reinforcement of the Funthams Lane to Chatteris number two circuit, and;
- Busbar reinforcement at Trowse Grid.

Please refer to the Regional Development Plans for further details.

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.

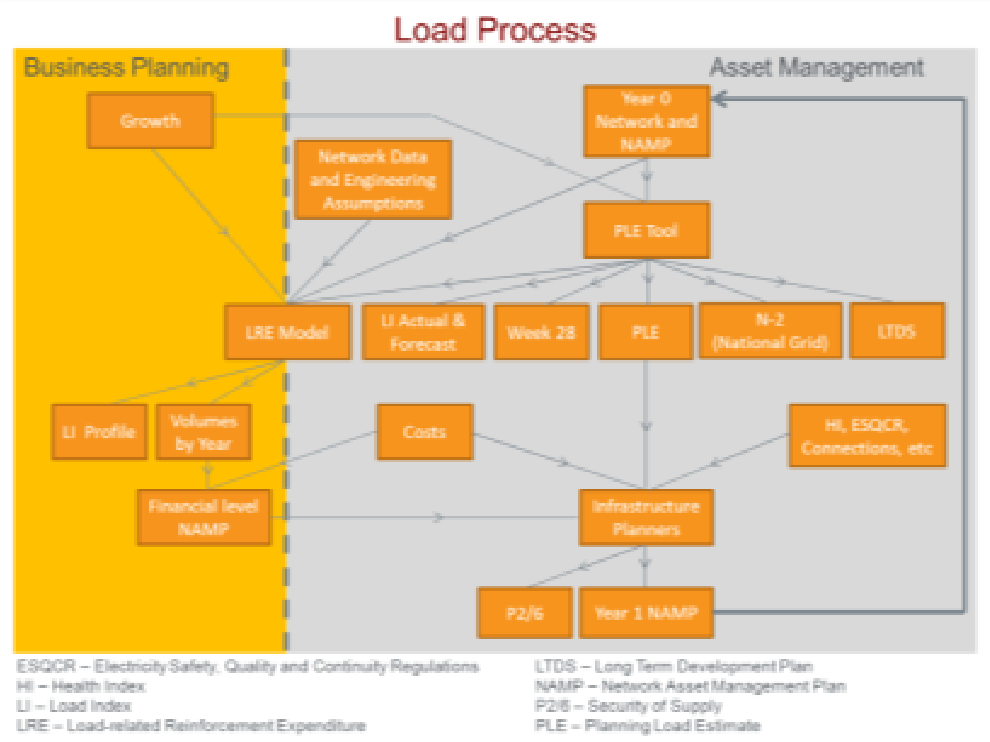

Figure 23: Information Flow

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 23).

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 46).

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 46: 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 24.

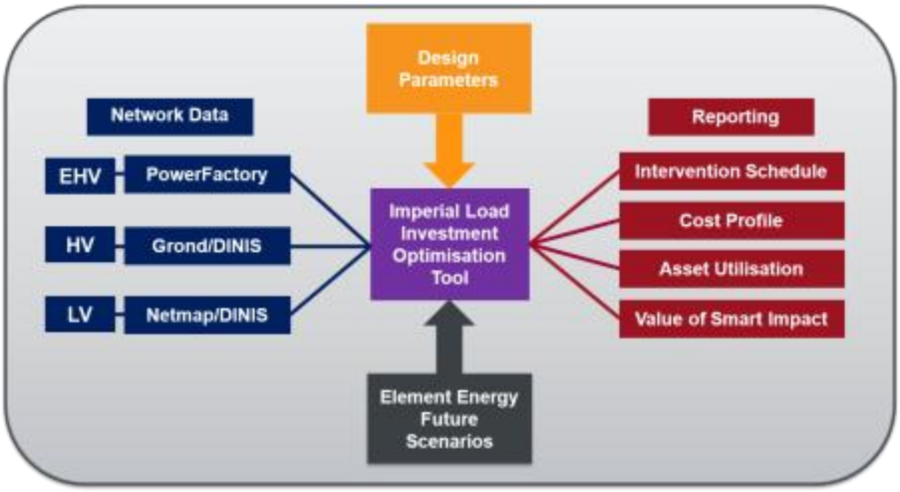

Figure 24: LRE Model Structure

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	Use values from

(DTX)	Ellipse/GROND
HV Circuit (11kV/6.6kV)	Ellipse
Primary Substation	PowerFactory
EHV Circuits (33kV/132kV)	PowerFactory
Grid Substations	PowerFactory

Table 47: 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 48: 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 49: 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 49 and 50). 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 50 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 50: Intervention Parameters

Methodology

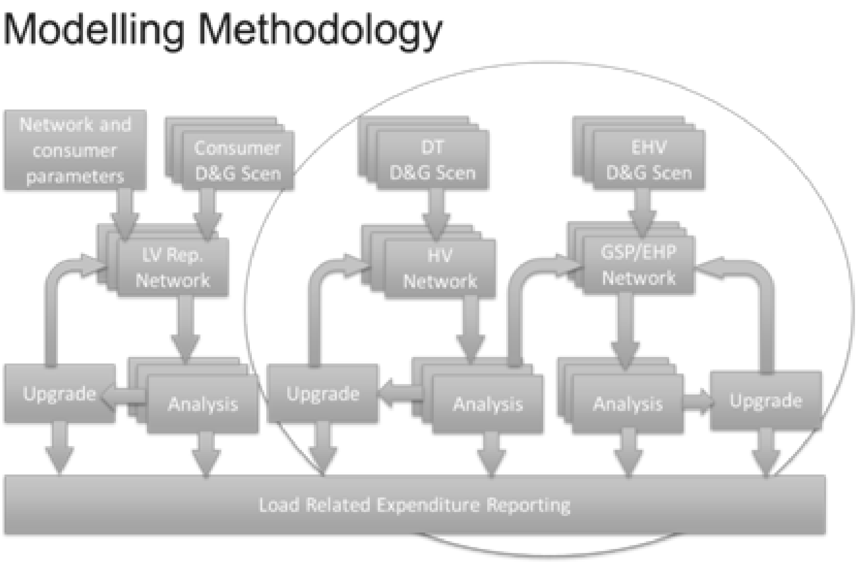

Figure 25 – Modelling Methodology

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 26) are applied in the model if the load forecast does not predict any future growth after a site capacity is breeched:

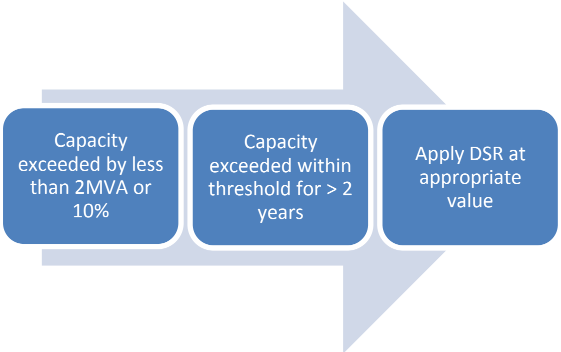

Figure 26: Rules applied in the Model if load forecast does not predict any future growth after a Site capacity is breeched

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 27) are applied in the model if the load forecast does not predict any future growth after a site capacity is breeched:

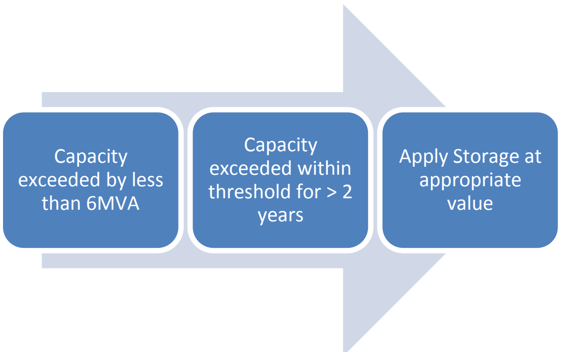

Figure 27: Rules applied in the Model if the load forecast does not predict any future growth after a Site capacity is breeched

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, overruled by PLEs)

Grid	Substation type	Year of Replacment	Voltage	Sum of Rating	Sum of Recommended Replacement	Sum of Replacement Cost
BOURN PRIMARY	GMT	2017	HV	500	800	14587.7096
BOURN PRIMARY	GMT	2024	HV	200	315	10877.8996
Bourn Primary 11kV	Primary	2027	33	19.6	24	759918.8558
HALSTEAD PRIMARY	PMT	2032	HV	15	50	9358.1396
Hendon Way Primary 11kV	Primary	2032	33	48	60	836005.8342
HENSTEAD PRIMARY	GMT	2014	HV	100	200	14347.2696
HENSTEAD PRIMARY	PMT	2024	HV	5	50	9358.1396
HORNCHURCH LOCAL PRIMARY	GMT	2030	HV	315	500	13457.88
LUTON NORTH GRID	GMT	2021	HV	315	500	13457.88
LUTON NORTH GRID	GMT	2032	HV	315	500	13457.88
MELTON PRIMARY	PMT	2028	HV	5	50	9358.1396
MELTON PRIMARY	PMT	2031	HV	5	50	9358.1396
MERRYHILL PRIMARY	GMT	2027	HV	600	1000	28934.9792
MERRYHILL PRIMARY	GMT	2029	HV	350	800	14587.7096
Newtown Primary 11kV	Primary	2025	33	30	36	731797.8342
PLAYFIELD PRIMARY	GMT	2032	HV	315	500	13457.88
ROYSTON PRIMARY	PMT	2028	HV	10	50	9358.1396
SOUTH HARLOW PRIMARY	GMT	2024	HV	200	315	10877.8996
SOUTH HARLOW PRIMARY	GMT	2028	HV	300	500	13457.88

Table 51: Example of EPN Substation Intervention Output Table

Switchgear Interventions

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

Year	Voltage	Substation	Name	Violation type	Old Rating	New Rating
2029	33	Bury St Primary 33Kv	BUSTT_BUST_1_CB	Continuous	800	1250
2026	11	Chaul End Primary 11Kv	BS 1-2	Continuous	1250	2000
2026	11	Eastcote Primary 11Kv	1449037	Continuous	400	630
2030	11	Eastcote Primary 11Kv	1449040	Continuous	400	630
2031	11	Elstree Primary 11Kv	1335408	Continuous	400	630
2025	11	Exning Primary 11Kv	764434	Continuous	400	630
2030	11	Frogmore Primary 11Kv	491977	Continuous	400	630
2025	11	Fulbourn Grid 11Kv	T2_CB	Continuous	1200	1250
2029	33	Hatch End Grid 33Kv	2T0	Continuous	1200	1250
2031	33	Holywell Grid 33Kv	BS 1-2	Continuous	2000	2500
2030	33	Hornchurch Grid 33Kv	T5_CB	Continuous	1250	2000
2029	33	Huntingdon Grid 33Kv	HUNT_STIV_1_CB	Continuous	800	1250

Table 52: Example of EPN Circuit Intervention Output Table

Circuit Interventions

- Thermal Constraints
- Voltage Constraints

Grid	Year of Replacment	Feeder Reference	Sum of Replacement of overhead line length		Sum of Replacement undergound length	
			Thermal	Voltage	Thermal	Voltage
ABBOTS CENTRAL PRIMARY 11kV	2013	1505073			0.3162	
ABBOTS CENTRAL PRIMARY 11kV	2022	1505073			1.1136	
ABBOTS CENTRAL PRIMARY 11kV	2025	1505073			1.1136	
ABBOTS CENTRAL PRIMARY 11kV	2027	1505073			0.2586	
ABBOTS CENTRAL PRIMARY 11kV	2029	1505073			0.2586	
BOURN PRIMARY 11kV	2022	1523788	0.2968			
BOURN PRIMARY 11kV	2025	1523788	0.0428			
BOURN PRIMARY 11kV	2027	1523788	0.5794			
BOURN PRIMARY 11kV	2029	1523788	0.0632			
BOURN PRIMARY 11kV	2030	1523788	0.1734			
BOURN PRIMARY 11kV	2032	1523788	0.1887			
DANBURY PRIMARY 11kV	2014	849286	0.207			
DANBURY PRIMARY 11kV	2027	849283		11.28		
DANBURY PRIMARY 11kV	2027	849286	0.484			
DANBURY PRIMARY 11kV	2029	849283	0.45	14.226		
DANBURY PRIMARY 11kV	2030	849283	0.925	12.937		2.179
DANBURY PRIMARY 11kV	2030	849286			0.055	
DANBURY PRIMARY 11kV	2032	849286			0.055	
ORMESBY PRIMARY 11kV	2032	1105377			0.003	

Table 53: Example of EPN Circuit Invention Output Table

LRE Model – Next Steps

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 28 shows the process flow.

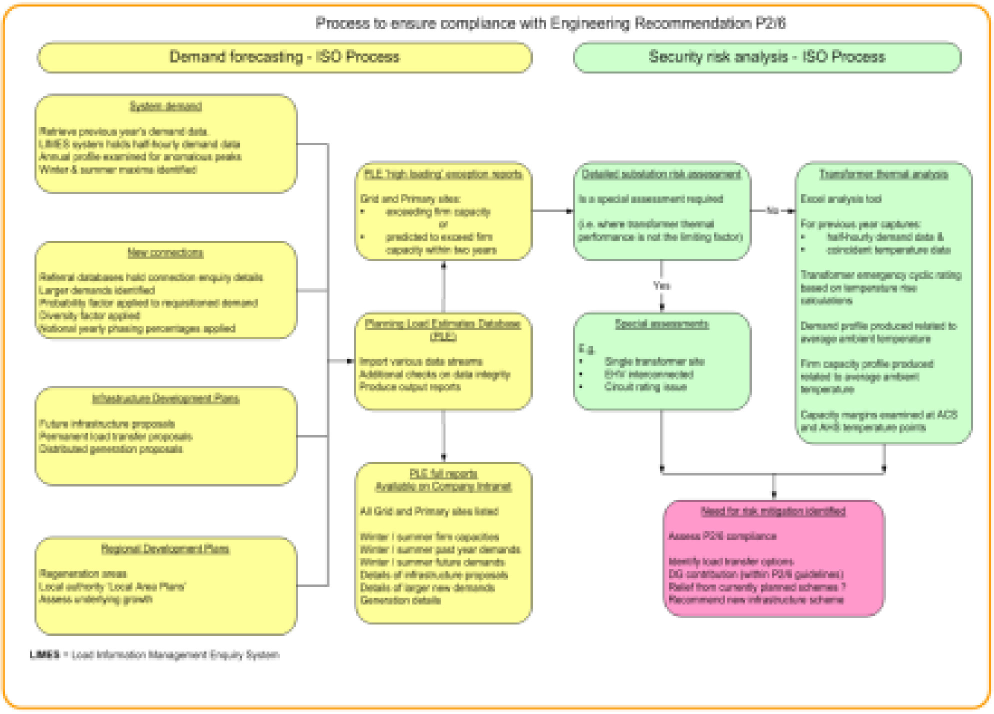

Figure 28: P2/6 Process Flow

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 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.

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 29 provides an overview of the "Regulated Project Approval Process" with relative Gateways (A to E)

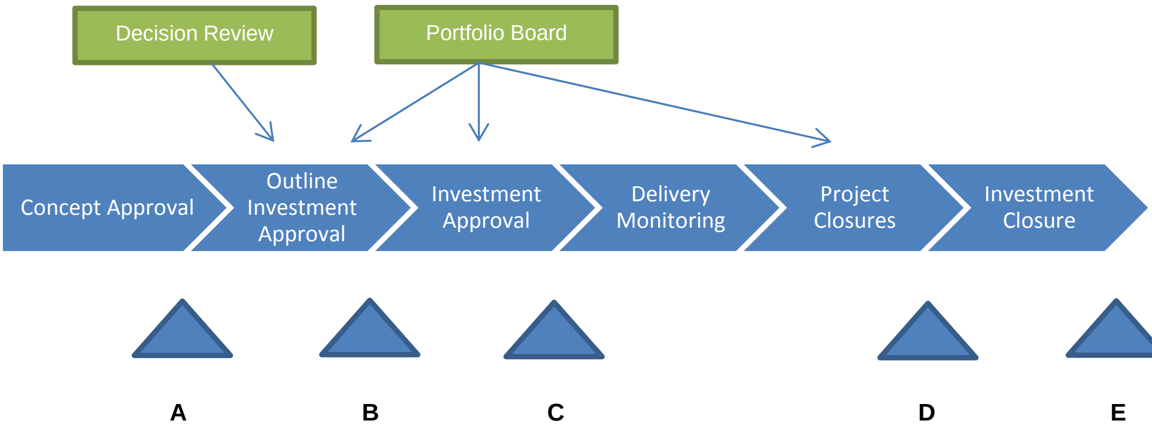

Figure 29: Project Investment Gateway process

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 54: 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 the process flows associated with the governance are shown below.

PG&C Project Gate A Approval to Gate E Review

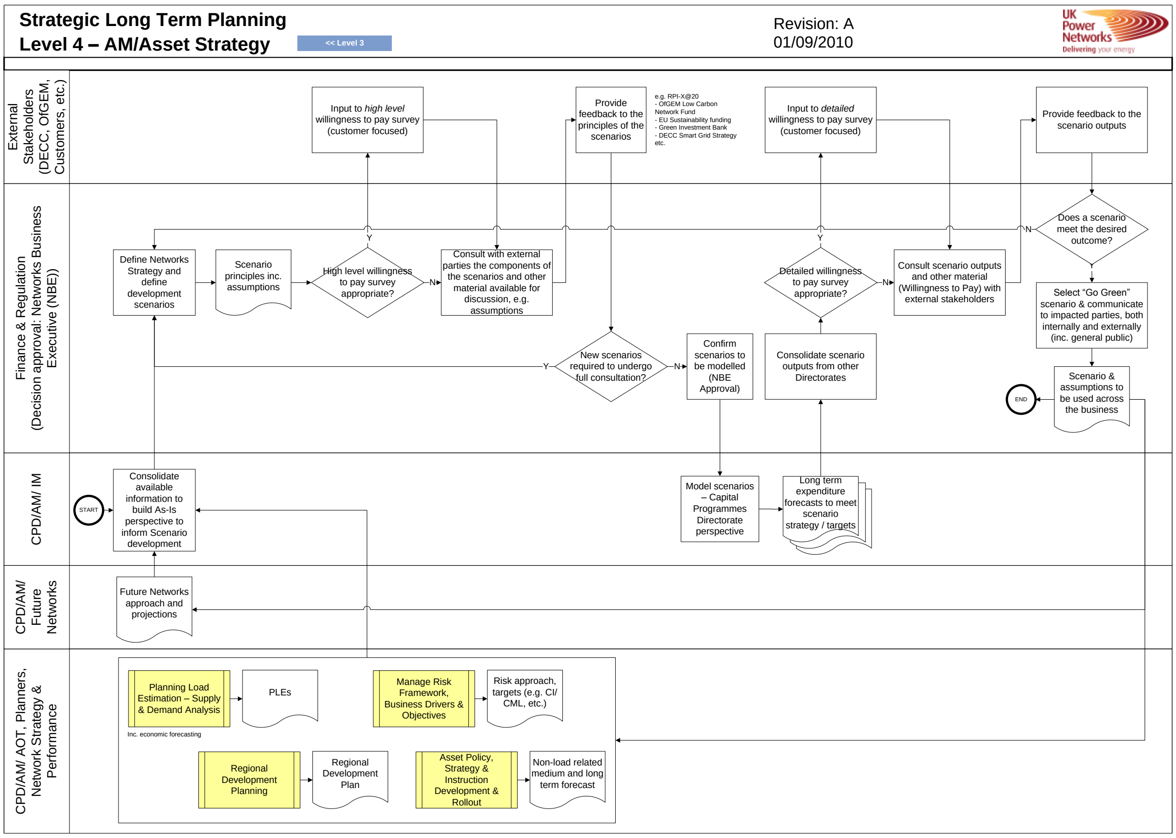

Figure 30: High level view of scenario planning.

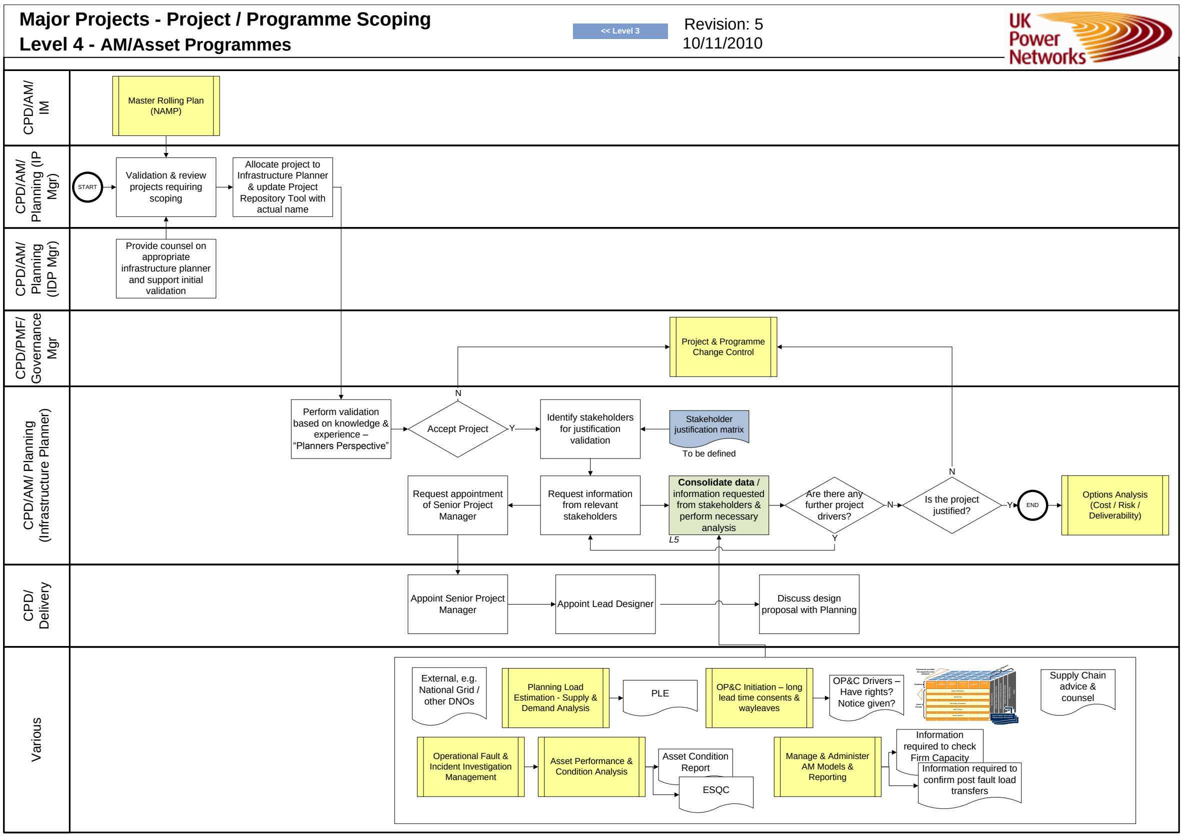

Figure 31: Specific project validation

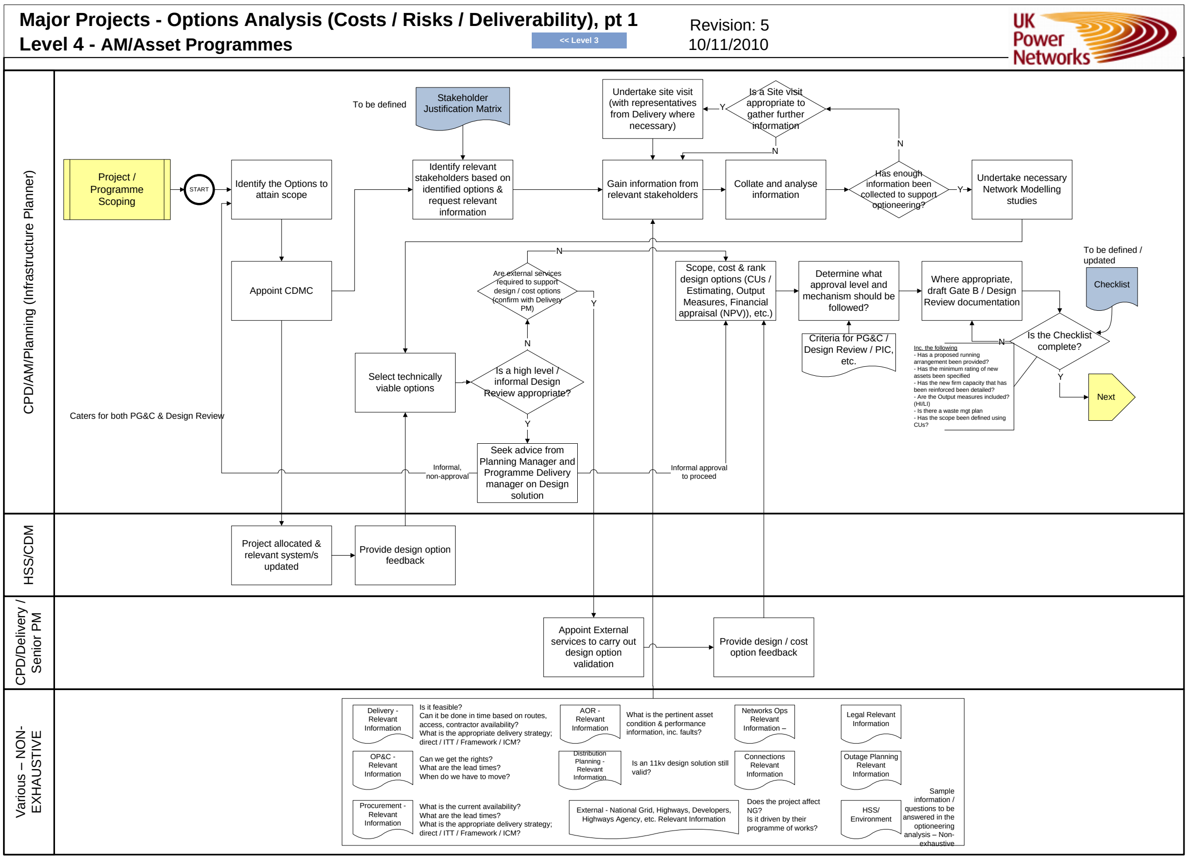

Figure 32: Specific project scoping up to Design Review

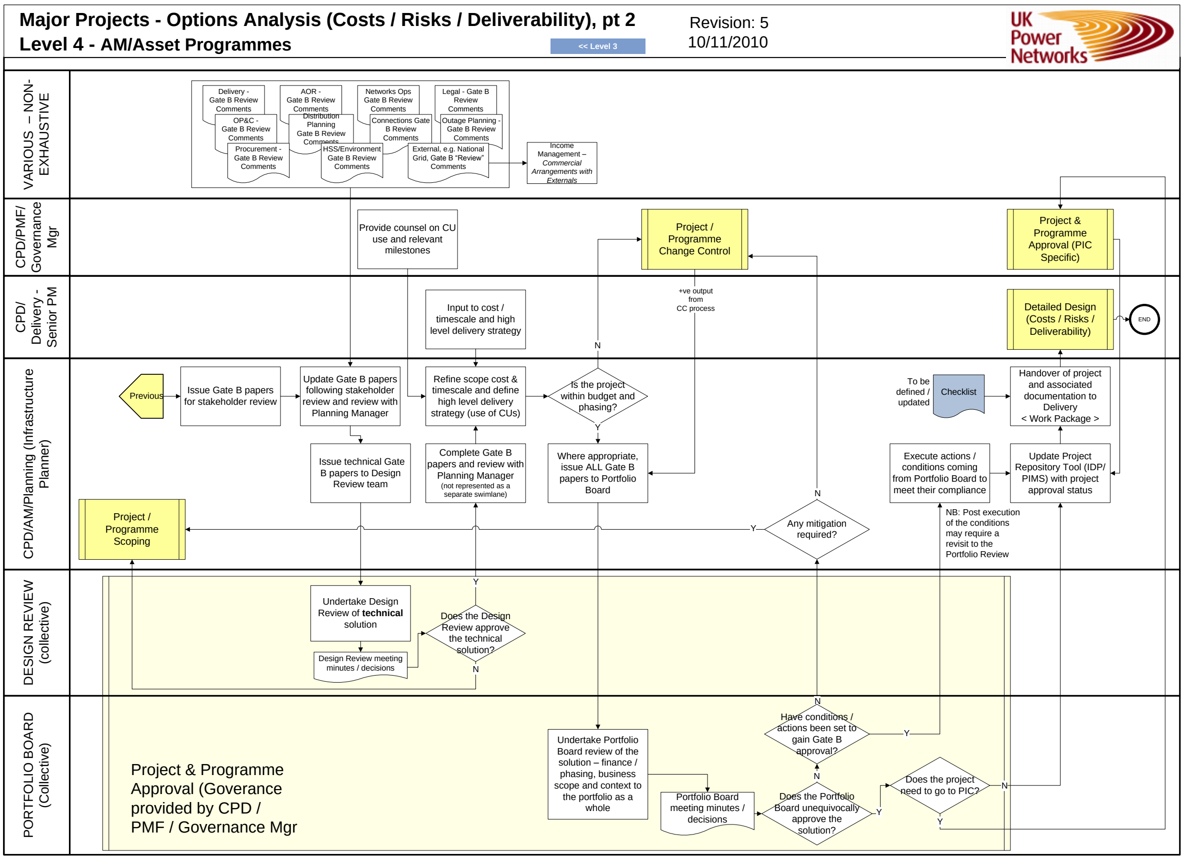

Figure 33: Specific project scoping from Design Review through Gate B to Delivery handover

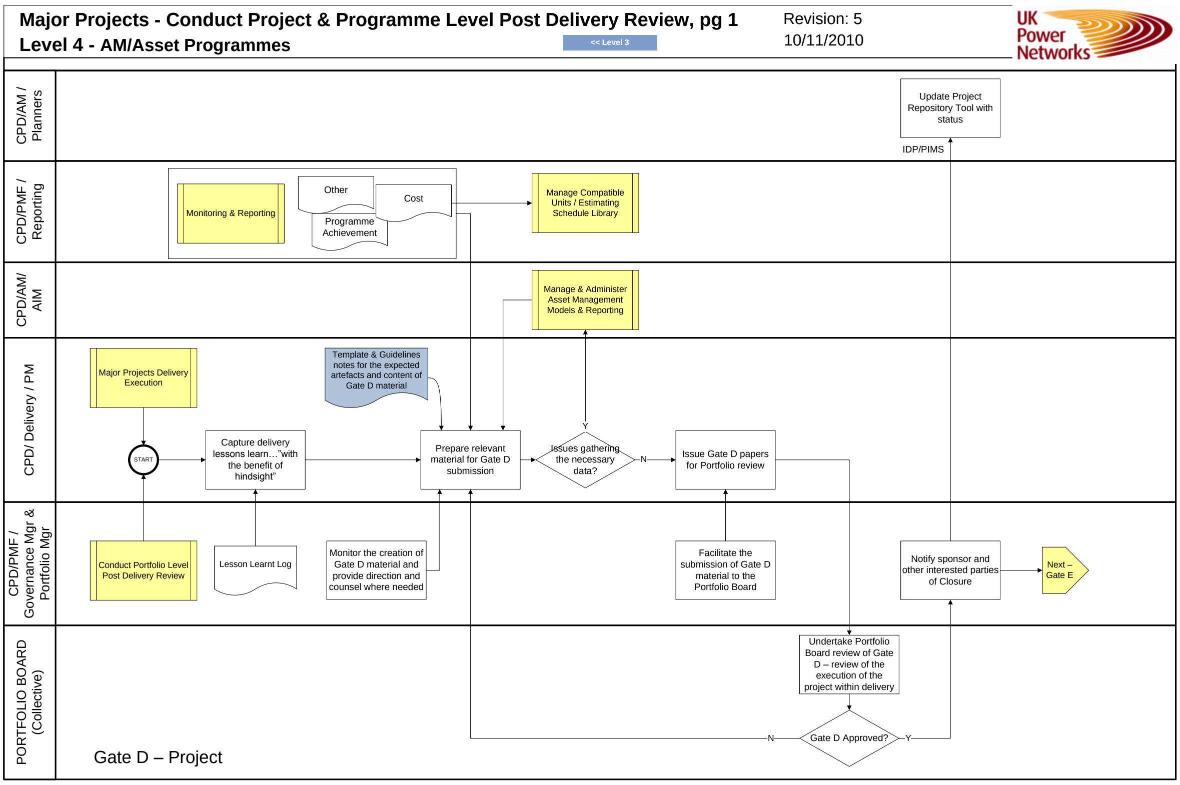

Figure 34: Specific Project Gate D Project Closure

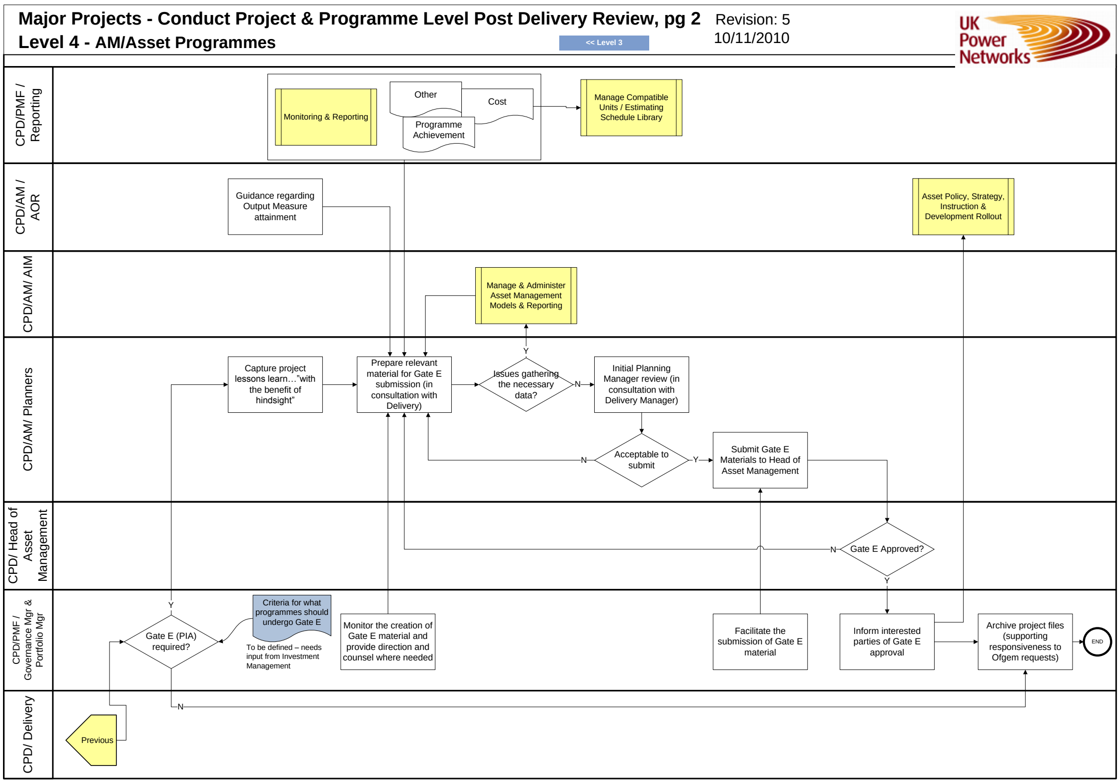

Figure 35: Specific Project Gate E Project Closure