ANNEX 21: REINFORCEMENT MODELLING

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1. Executive Summary

Our network is designed to cope with the peak demand on it, such that it remains able to supply electricity even when demand is at its highest point. Demand fluctuates significantly through the day and the year such that there is often significant spare capacity not being used.

As demand for electricity grows in the future, we have to ensure that the network is adapted to cater for these additional demands. The forecast need to adapt the network is set against the regional economic forecast for our operating area and the wider context of the UK fourth Carbon Budget Plan that seeks to reduce CO_2 emissions by 35% (from 1990 levels) by 2023 and by 80% by 2050.

To deliver the fourth Carbon Budget, it is anticipated that demand for electricity will increase, with a doubling of demand by 2050 possible; however there is significant uncertainty as to when and where the increase in observed demand will materialise.

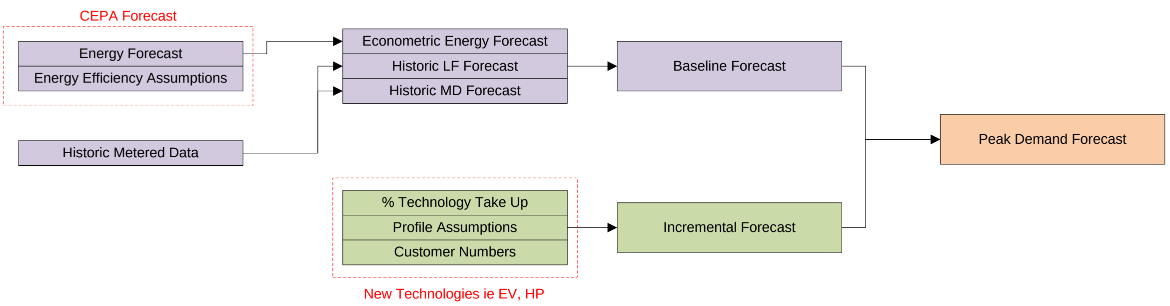
The Department of Energy and Climate Change (DECC) have prepared four potential scenarios for the impacts of de-carbonisation and forecast take-up rates for Low Carbon Technologies (LCTs) such as Electric Vehicles (EVs).

Within the RIIO-ED1 period, our stakeholder engagement and analysis shows that our region is likely to emerge more slowly than others from the economic recession and that its record of new technology adoption lags other areas. As a result, the forecast adoption rates will be relatively lower than other areas such as the south east. We therefore believe that the DECC Low scenario represents the most likely scenario for LCT adoption for our region.

2. Demand Forecasting

In order to identify those parts of our network that require future reinforcement, we need to develop an approach that forecasts future demand and can model the impact of any additional demand on the existing network.

Our demand forecasting methodology delivers a peak demand forecast that consists of a baseline forecast and an incremental forecast as shown in the figure below.



The baseline forecast predicts the annual peak demands that we would expect to see based on the typical types of demands connected today and as affected by forecast economic activity.

The incremental forecast predicts the impact of known large new connections, and perhaps more significantly, the impact of achieving the fourth Carbon Budget.

2.1 Baseline Forecast

We commissioned external experts CEPA to produce a background (or ‘business-as-usual’) energy forecast to 2023 from a base position at 2011. The forecast used several economic growth and electrical appliance efficiency saving assumptions to produce a load growth forecast.

The economic factors, and their source data, which have an impact on electricity demand in these scenarios are:

Factor	Source
Economic growth (GVA)	North West Economic Forecasting Panel
Household Income	equated to productivity figures
Housebuilding rates	Office of National Statistics
Price of Electricity	DECC central case for domestic/commercial prices

Non-economic factors which affect electricity demand are energy efficiencies brought about by policies on lighting, product efficiency and smart meters.

In overall terms, we anticipate that the UK economy will recover from the current recessionary state, however the North West region of England typically lags behind other areas of the UK in respect of economic performance. For the purpose of the RIIO-ED1 forecast, we have therefore adopted the CEPA central scenario as the appropriate balance between strong growth and a stalled economy.

Since our original submission we have revisited the assumptions underlying our forecast and are confident that they remain valid. We have also examined winter 2012 load data and whilst at the micro level some symmetrical changes are evident, the net effect within the overall uncertainty of the forecast is negligible.

The ratio of average load to maximum load gives the Load Factor (LF) on a piece of equipment. For a constant Load Factor (LF), the energy forecast is directly proportional to the power forecast. However, it has been observed that LFs have been reducing in recent years, ie the difference between average and maximum has been growing and the load is getting more ‘peaky’. To convert the energy forecast into a power forecast, a forecast of LF is required for each Bulk Supply Point (BSP). The LF forecast is produced using regression analysis techniques operating on cleansed historical LF data.

A second power forecast is produced using regression analysis techniques operating on cleansed BSP historical annual peak demands.

The two power forecasts are combined into a single baseline forecast of power disaggregated by BSP.

2.2 Incremental Forecast

The incremental forecast addresses demand growth caused by known significant new connections (those not covered by the background factors considered by CEPA) and by the increasing connection of new low carbon technologies (often driven by external atypical factors such as government incentives), which cannot be predicted by a forecast based on historical data. In particular, during RIIO-ED1 we anticipate a potentially significant take up of EVs and HPs that will impact on peak demands, particularly beyond 2020.

The incremental forecast is added to the baseline forecast to produce the peak maximum demand (MD) forecast.

Having established a regional forecast, we then need to break this down further, as not all parts of our region will behave in the same way. To reflect more adequately the sub-regional adoptions of LCTs within our network; for example EV adoption rates in Manchester versus Ulverston, we have assumed EV and HP penetration levels consistent with DECC's Carbon Plan nationally but at levels appropriate to each Local Authority (LA) within our area.

The Tyndall Centre (part of the University of Manchester) has advised us on the take-up of these LCTs by Local Authority area based on known uptake and clustering observed with the take-up of PV cells. For EVs, we have based the sub regional forecast on the Transport Research Laboratory forecast for our region.

Our 'best view' reinforcement expenditure forecast assumes a peak demand forecast that is aligned to DECC scenario 4 (Purchase of international credits).

3. EHV and 132kV General Reinforcement

3.1 LI methodology

In order to measure performance in respect of efficient management of 132kV and EHV network capacity and delivery of reinforcement projects that provide increased capacity, we use a Load Index (LI) measure that ranks the ability of the parts of the network to supply maximum demand.

In order to establish the Load Index for all parts of the network, our network is sub-divided into groups. All groups which consist of a single substation are included in the analysis. Where the group is formed from a number of substations, only those that are considered material are identified.

To model the LI, the Firm Capacity (FC) of all the groups is calculated. This represents the maximum load that the site can provide. Where the group is a single substation this is a relatively easy task that relates to plant capacity and transfer capability, and is constant annually (for a fixed network configuration). Where the group is formed from a number of substations, the FC can only be calculated by network modelling techniques.

The 2023 forecast peak demands are applied to the groups and compared against the calculated FC to establish the groups' Load Index (LI).

The Load Index classification corresponds with that required by Ofgem and uses the following five point scale;

LI band	Descriptor	MD/FC	Time over 100%
1	Significant Spare Capacity	0-80%	n/a
2	Adequate Spare Capacity	80%-95%	n/a
3	Highly Utilised	95%-99%	n/a
4	Fully Utilised – Consider mitigation	>=100%	<9 hours
5	Fully Utilised – Mitigation required	>=100%	>9 hours

For all groups with a forecast 2023 peak demand greater than 100MW, an additional N-2[1] compliance assessment is also carried out and any non-compliance identified.

A desktop exercise develops high level reinforcement solutions for all identified network issues. These solutions take into account the overall system performance and the status of

[1] That is, the ability of the network to withstand two simultaneous incidents

neighbouring parts of the network to ensure efficient and economic development of the network.

Having identified the issues and preferred solutions, the resulting projects are costed using the assumed construction costs in the RIIO-ED1 period. This includes an assumption for ongoing efficiency reductions through the period.

In order to ensure that a single integrated programme is planned, the requirements of the reinforcement programme are matched against those from other drivers to ensure that any duplication is removed and that the proposed solution meets the needs of all relevant drivers on that site or portion of network.

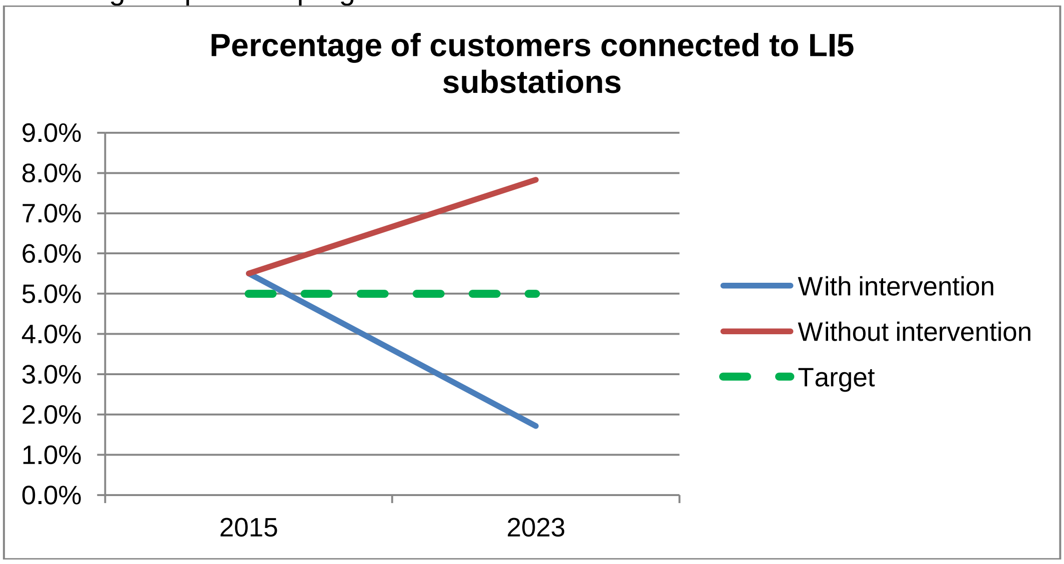
The profiling of expenditure takes into account the most heavily overloaded demand groups, demand groups with limited alternative feeds and deliverability constraints. Other considerations include avoiding simultaneous projects in the same area of the network to avoid operational difficulties obtaining the necessary outages and ensuring a smooth, efficiently deliverable programme.

The peak demand forecasting methodology intrinsically includes new demand brought about by new connections. Therefore, the identified reinforcement projects include reinforcements under the Low Volume High Cost (LVHC) Connections category. A reduction in general reinforcement expenditure is included to address this forecasting overlap. The size of this reduction is equal to the gross (of contributions) amount of connections related reinforcement specified in the connections submission.

3.2 LI strategy

Using a weighting of the LI grades (1-5) against each other and the customers supplied by each substation as an aggregating factor, we can total the overall ‘loading risk’ at a point in time and see how this changes in the future, both with and without the impact of proposed investment.

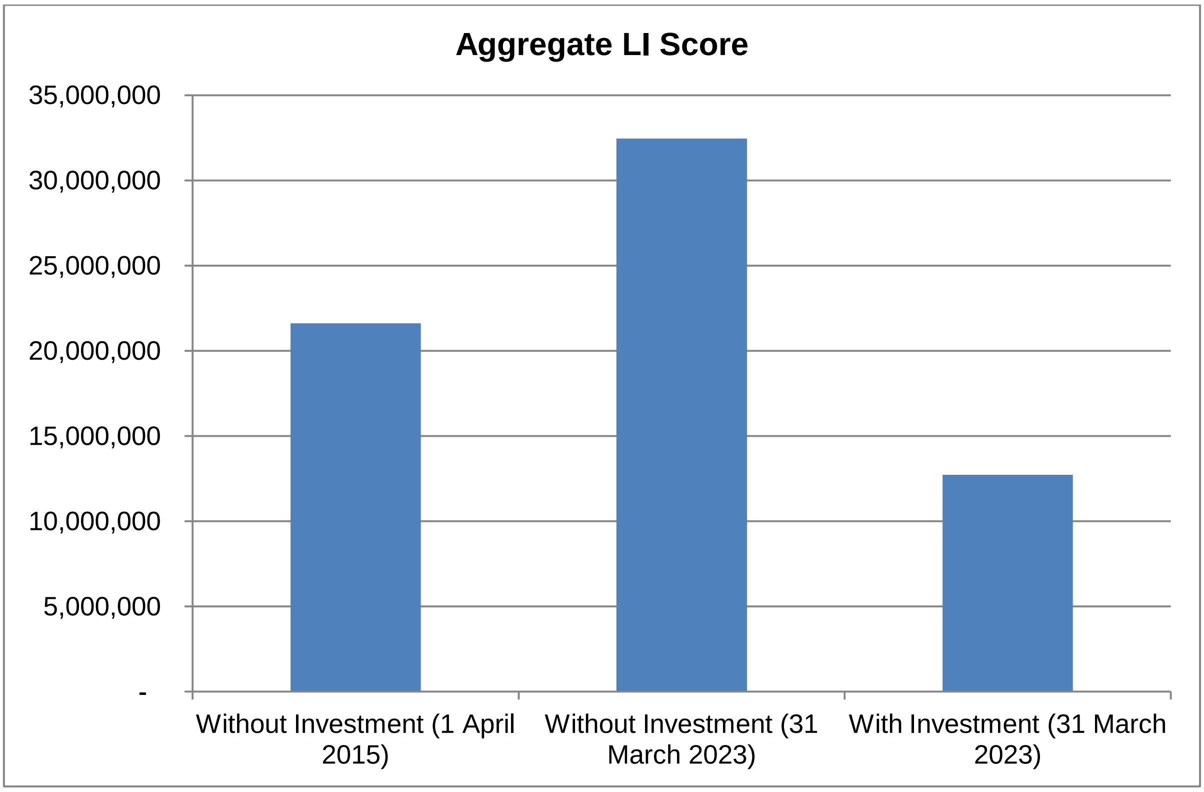
We can also articulate this in terms of the numbers of customers connected to overloaded substations. We forecast that this will be around 5.5% at the end of DPCR5. If we make no further investment, this will increase to 9% by 2023, however, we will reduce this to 1% by delivering our planned programme.



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

We plan to reinforce 21 major sites and five groups during RIIO-ED1 at a cost of £39.3 million.

In overall terms, the weighted LI risk will halve from its projected 2015 level following the proposed investment rather than double as it is otherwise projected to do. This is due to the planned reinforcement of a small number of sites in the LI=5 category with large numbers of connected customers in the RIIO-ED1 period.



4. LV and HV General Reinforcement

We have developed a software model for the whole of the HV (feeders from the primary substations) and LV network that allows network overloads at these voltages to be identified. This model is termed the Future Capacity Headroom (FCH) model.

Inputs to this model are plant ratings and existing loading levels derived from corporate data, and the peak demand forecast. The same baseline forecast is used for loading on a particular asset as that calculated for its supplying BSP and the same incremental forecast is also used; however additional assumptions are made about the distribution/clustering of the incremental forecast, ie the distribution/ clustering of the penetration of the LCT take-up.

Outputs from the model are counts of assets that are loaded beyond their thermal rating. The uncertainty in exact location of LCT penetration means that the results for future overloads are only valid as counts in aggregate and cannot be asset specific.

The FCH model also counts assets where the installed thermal capacity of LCT (including PV) exceeds an indicative threshold of thermal rating indicating when voltage/harmonic issues are likely to occur at the LV network level.

Modular solutions and associated costs have been developed to address the following issues on the HV and LV networks:

- Thermal overloads – HV feeders
- Thermal overloads – LV feeders
- Thermal overloads – distribution (HV/LV) transformers
- Over-voltages – LV feeders
- Harmonic issues – LV feeders/Distribution substations

Some older properties, typically terraces and townhouses, are supplied by a looped service cable where a single cable is taken from the low voltage main cable and is 'looped' from one property to the next to provide the electricity connection. This means that the electrical demand of a number of properties is supplied from service rather than mains cable.

Historically this has been acceptable because of limited demand and diversity across demand. However in the future, LCT devices such as electric vehicle chargers will require large amounts of electricity and there will be a high probability that they will be simultaneously used in a number of properties. If these properties are fed from a looped service cable, that cable will quickly overload and fail. We are therefore proposing to address this issue by removing looped services and providing discrete services to each property.

The profiling of this expenditure over the RIIO-ED1 period reflects the expected uptake of LCTs over the period.

For completion of our secondary network LCT driven reinforcement submission, we have used the Transform model developed by EATL for all the GB DNOs to assess the impact of Low Carbon Technologies on GB electricity distribution networks (See Annex 20) with appropriate regional settings as detailed in our submission tables. The FCH model has been used to both verify the outputs of the Transform model against 'traditional' solutions and to derive the forecast for elements such as harmonics not covered by Transform.

5. Smart Grid and Smart Meter benefits

We have carried out considerable work on smart grid (see Annex 29) and smart meter (see Annex 28) based solutions as an alternative to traditional network reinforcement techniques for both demand and generation customers. This work has been led by ourselves in areas such as DSR, active voltage management and meshed network techniques but also done by or in collaboration with other DNOs through various industry working groups and other DNO projects. Whilst it is not possible to define the exact smart grid / meter solution that will be applied to every intervention required in RIIO-ED1 we have ensured the forecast benefits of this work are appropriately included within our forecasts and hence accrue to our customers.

For secondary network expenditure we have based the majority of our forecast on the Transform model. Certain investment drivers such as service un-looping and power quality are not covered within the Transform model and for these we have modelled the required volume using our Future Capacity Headroom model and priced using modelled unit costs. Transform contains details of all known smart solutions and incorporates all solutions contained within our smart grid strategy. In particular, we would expect to deploy network meshing, voltage management and DSR on secondary networks and have included this smart grid discount within our forecasts.

For the 132kV and EHV system we have calculated our base reinforcement requirement on traditional solutions priced using efficient unit costs and then discounted the price by 20% to reflect the value we expect to deliver from deployment of smart solutions such as C_2C DSR developed by ourselves and techniques such as active network management pioneered by SSEN.

In addressing our forecast reinforcement programme we have also closely examined the likely challenges presented by Distributed Generation customers. We have included a modest forecast for DG-driven reinforcement as we intend to utilise C_2C managed connection contracts at EHV and HV and connect and manage techniques at LV. These approaches we believe will enable significant amounts of DG to be connected at lower costs on already congested networks. In specific areas we envisage deploying site- based Active Network Management solutions; however our overall strategy for DG is to develop and deploy centralised active network optimisation. We have included costs for this as part of our NMS replacement project (see Annex 18).

Smart metering will bring further benefits to customers and assist in reducing network load-related expenditure. In particular we expect to see the information from smart metering advising loading levels on existing assets and hence allowing us to run assets closer to their operational limits. Again such techniques and benefits are included within the portfolio of smart solution sets within Transform and hence are already included within our forecast. We would envisage smart meter benefits to become much more significant during the RIIO-ED2 period and have outlined these out of period savings in Annex 28 – Smart Meter Benefits.

6. Demand Side Response (DSR)

We have been looking at the role that DSR contracts can play in mitigating reinforcement investment requirements in DPCR5 and have instigated a number of contracts with industrial customers in the period. DSR contracts are a possible option where there is some doubt over the sustainability of load growth and hence a risk of under-utilised investment if additional capacity is installed, or where the load characteristics driving the loading issue are related to a single customer. They are also useful mechanisms to buy some time where proposed network solutions that may solve multiple loading issues are in development. As such, we see them as a useful intervention strategy.

The actual number and value of contracts signed will depend on the economic case in each instance, and the willingness of customers to sign up to such an agreement.

Our CBA analysis of techniques such as C_2C shows a strong benefit of such DSR approaches – for further details please see Annex 3. For secondary network investment, DSR is one of the smart solution sets within Transform and hence is included appropriately in our submission. As noted, we have discounted our plan for Grid and Primary reinforcement by 20% to reflect the anticipated DSR benefits of solutions such as C_2C, CLASS and other learned approaches from smart trials.

7. Fault Level Reinforcement

The equipment that forms the electricity distribution network has to be able to cope with the large amounts of electrical energy that flow when faults occur. The amount of energy that would flow in a particular part of the network under worst case conditions is known as the fault level.

Some areas of our network have older items of equipment connected which have a limited ability to cope with high levels of fault energy (a lower fault level rating). We have designed our network to limit the fault energy to be as low as possible at this equipment in order to maintain safety, but this does constrain our ability to connect new sources of electrical energy like distributed generation, as well as the widespread adoption of LCTs, in a particular area.

In RIIO-ED1 we are proposing to remove equipment that we have identified as not having a fault level rating consistent with modern standards and that is potentially constraining new LCT connections and the way we operate the network. Replacement of this equipment typically has long lead times of up to two years and hence to facilitate the prompt connection of LCTs by customers it is proposed to remove this sub standard switchgear from the network over two price control periods.

7.1 Modelling

Calculation of 132kV, 33kV and HV (at primary substation busbars) fault levels is undertaken through network modelling. We use the IPSA+ network analysis tool and maintain an IPSA Network Model (INM) of the 132kV, 33kV and HV network. The model also incorporates a reduced representation of the transmission network, which is set up for maximum fault level operating condition.

The INM has been updated with the 2023 peak demand forecast and the corresponding G74 motor in-feed contributions. The transmission system is assumed to remain constant. Fault 'make and break' calculations are undertaken for three-phase and single-phase short circuit faults. Switchgear calculated to have a fault level in excess of its fault rating has then been identified for replacement or reinforcement.

A desktop exercise developed high level reinforcement solutions for all identified fault level issues. These solutions take into account the overall system performance and the status of neighbouring parts of the network to ensure efficient and economic development of the network.

Costs were developed for the preferred solutions based on our projected view of unit costs and consistent with future efficiency assumptions. As was the case with the reinforcement programme, any overlap with the asset replacement programme was reviewed and duplicated units removed from the fault level forecast.

7.2 Options

Fault level management is a critical network safety factor and at this time we do not consider that alternate technology solutions such as fault current limiters will be economically viable at EHV in the RIIO-ED1 period. All solutions selected are therefore based on proven techniques and we have identified the construction delivery risks (equipment outage risk, consents acquisition risk etc) and designed what is believed to be a deliverable solution within the RIIO-ED1 period.

Our CBA analysis indicates that use of alternate solutions such as fault current limiters is currently uneconomic for several reasons:

- The capital cost of such solutions is comparable with traditional solutions however such devices have a relatively high operating cost;
- The plant concerned is generally towards the end of its operating life and will require replacement on HI grounds before the end of RIIO-ED2; and
- The technology risk arising from the present embryonic manufacturing base for these devices precludes a rapid and reliable deployment programme.

We will monitor ongoing smart technology developments and where possible incorporate these into our actual delivery plan. This is an area of active research in our innovation plans and we have included two new potential techniques within our innovation strategy to manage future fault level issues on EHV networks (see Annex 23). These techniques are revolutionary in nature and consequently at a low technology readiness level hence we have not factored them into our forecast.

7.3 HV and LV Fault Level Reinforcement

The conurbations within our operating area have HV networks operating predominantly at the 6.6kV level. A proportion of the switchgear in these areas is fault rated below the present UK design standard of 21.9kA. This equipment often represents a significant barrier to the connection of LCTs such as heat pump motor load and DG. Replacement of this equipment typically has long leads times of up to two years and hence to facilitate the prompt connection of LCTs by customers it is proposed to remove this sub standard switchgear from the network over two price control periods.

The criteria used to identify and prioritise 6.6kV secondary network switchgear for replacement are:

- Fault level rating of switchgear is less than 20kA
- Current feeding primary substation HV fault level greater than 13.1kA
- Current feeding primary switchgear greater rated greater than or equal to 20kA.

The above criteria identify all 6.6kV switchgear rated less than 20kA where there is a likelihood of the fault level rating exceeding equipment rating and allows for the grouping of switchgear changes by primary substation. This strategy allows us to certify that a particular primary is unlikely to have fault level issues for connection of LCTs and hence release the maximum amount of capacity in the shortest time.

We have examined all present innovation work in the area of HV fault level management. Our analysis shows that for the particular issues we face; namely HV Ring Main Unit ratings remote from primary substation sites, then the optimal intervention given the asset age and condition is to replace with modern equipment.

Costs for replacing the 6.6kV switchgear are based on a like-for-like replacement using standard unit costs and any overlap with the non-load programme has been removed as stated above.