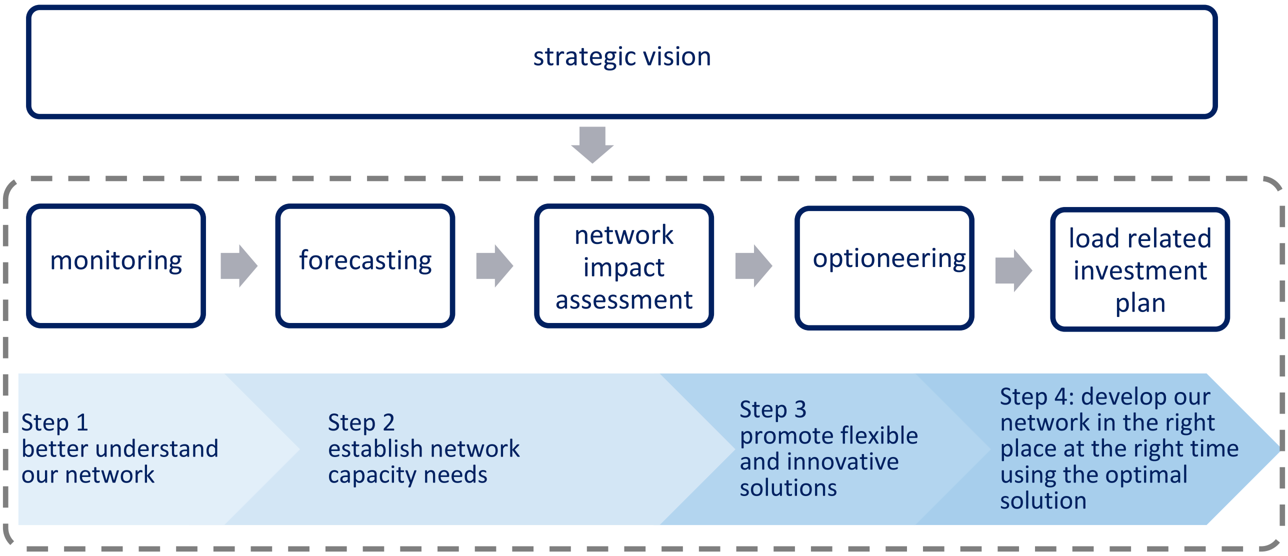
Annex 3B: Load Related Expenditure Methodology – Part B

December 2021

CONTENTS

EXECUTIVE SUMMARY

This document is Part B of our three Load Related Expenditure Annexes (ie Annex 3B) and it describes the methodology followed to produce Electricity North West's RIIO-ED2 load related investment plan and the associated justification. The methodology is based on Ofgem's informal framework guidance. Our strategic vision for load related investment applies to the whole of the end-to-end process of our methodology. As shown below, this process starts from the monitoring (all available measurements including smart meter data) and forecasting components that are required as inputs to network impact assessment and optioneering components that inform our load related investment plan.



Strategic Vision

Our strategic vision for RIIO-ED2 load related investment has three objectives:

i. to make sure that network will not be a barrier to the transition to Net Zero
ii. to implement an economic and efficient network development, and
iii. to manage uncertainties in a transparent manner.

These objectives can be met by our load action plan that focuses on market development (See DSO Transition Plan Annex 2) and is overlaid onto the end-to-end process shown above as a four step plan:

- in step 1 we better understand our network through expansion of monitoring to increase our visibility and data granularity in line with our Data and Digitalisation Strategies (Annexes 21 and 23 respectively
- in step 2 we establish network capacity needs through a) more granular and enhanced forecasts and b) network development plan cognisant of all Net Zero compliant scenarios to not foreclose credible alternative pathways
- in step 3 we adopt flexible and innovative solutions with a "flexibility first" approach, promoting flexible services and energy efficiency markets and facilitating third party solutions
- in step 4 we develop our network in the "right place at the right time" to deliver a reliable and cost efficient network with strategic interventions to avoid piecemeal network expansion.

The objectives of our strategic vision will be satisfied by the successful outcome of our load action plan. Customers will be able to connect local carbon technologies (LCTs) simply, they will not pay for excessive network development and customers and third parties will be empowered to deliver flexibility services. At the same time, we will continue to lead the North West to Net Zero.

Given that we are planning under significant uncertainties in RIIO-ED2, we acknowledge that there could be a need to revisit and recalibrate/redesign the steps of our action plan in the case that the objectives of our load related investment cannot be met. To do that we propose two indicators, ie one around customer experience and one around network utilisation. These indicators are performance measures that allow us implement a "control logic", where outcomes not delivering the objectives of the strategic vision will trigger a feedback loop correction and recalibration of the action plan. Further detail on our proposed output metrics is provided in our Load Related Expenditure – Investment Plan Annex (Annex 3A).

Monitoring

To better understand our network and the changing customer behaviour we will deliver greater visibility in RIIO-ED2 through:

- expanding the last point of permanent monitoring to lower voltages including neutral currents and power quality that are key for the facilitation of LCTs, and
- integrating smart meter data and other third party data sources.

Analysis of measurements will allow us to enhance our forecasts, make them more representative of local customer behaviour, increase their granularity and expand them to lower voltages. Through extensive monitoring we will also optimise our network planning and facilitate flexible services at lower voltages. This will help us both in reducing the risks of capacity shortfalls and increase savings in load related investment.

In line with our DSO Transition Plan (Annex 2) and Data Strategy (Annex 21), sharing more granular loading data across all voltage levels with our customers and stakeholders will promote market development. Sharing loading data from across our whole network will enable our customers and stakeholders to make well informed business decisions to provide flexibility services or deploy energy efficiency measures.

Forecasts

Our RIIO-ED2 load related expenditure (LRE) plan is informed by our [2020 Distribution Future Electricity Scenarios] (DFES). Aligned with our distribution system operation (DSO) Strategy and our Data Strategy, our DFES 2020 is the third annual publication where we have continued the engagement with regional stakeholders to understand their plans, future needs and requirements. To aid the development of local plans our DFES shares the knowledge, experience and data that informs our network planning for the benefit of our local communities, aiming to ensure there will be a coordinated whole system approach embedded into the Local Area Energy Plans (LAEPs) across our region.

Our DFES 2020 consists of four scenarios, agreed as part of the Whole System FES (see ENA ON WS1b P2) and a fifth Central Outlook scenario defined based on our ATLAS[1] forecasting methodology. Apart from DFES 2020 that are driven by national policies to meet Net Zero by 2050, our RIIO-ED2 LRE is also informed by an accelerated decarbonisation version of the DFES scenarios which consider the ambition of local authorities in our region to meet Net Zero before 2040.

Following Ofgem's business plan guidance, the LCT and demand forecasts from our DFES scenarios have been compared with FES and CCC forecasts. Alignment across scenarios has been highlighted and any differences between our DFES and the national trends shown in these two forecast sets are explained in this annex.

Our Central Outlook scenario has been identified as the highest certainty / "best view" scenario that does not foreclose post- RIIO-ED2 network futureproofing to the Net Zero transition. Central Outlook

[1] Architecture of Tools for Load Scenarios (ATLAS). NIA project, ENWL. Online: www.enwl.co.uk/atlas

is compliant with Ofgem's RIIO-ED2 guidance and as our "best view" scenario it has been considered to inform an optimal network investment plan to quantify our RIIO-ED2 baseline (ex-ante) allowance.

The other DFES scenarios and their accelerated decarbonisation versions have been used to a) inform a min-to-max investment range that could be funded by uncertainty mechanisms and b) confirm via cost assessments that Central Outlook scenario is at similar investment levels with the 2050 Net Zero scenarios and does not foreclose network development beyond RIIO-ED2 if decarbonisation is accelerated to meet ambitious early Net Zero targets.

Network impact assessment

All DFES 2020 scenarios and their accelerated versions have been used to assess future network impacts, ie thermal, voltage, fault level and harmonic distortion issues. Different approaches have been used to identify EHV (primary) and the HV & LV (secondary) network investment requirements because of the difference in volumes and costs of interventions required at different voltage levels, as well as the differences in the availability of monitoring data.

EHV network impacts have been identified through a range of processes that extend from a high level identification of network constraints using comparisons of local peak demand forecasts with substation capacity to more detailed power systems analysis where detailed electrical parameters and operational aspects are modelled for all EHV assets.

HV and LV network impacts have been identified using a range of tools and approaches depending on the type of issue. For example, thermal and voltage issues have been identified using our Future Capacity Headroom (FCH) model which exhibits comparative advantages from alternative options as presented in this document.

Optioneering

We have undertaken a comprehensive optioneering exercise based on the identified network issues associated with forecast levels of demand and generation. Following our DSO strategy that aims to increase savings from our load related expenditure, alternative approaches are thoroughly assessed to ensure that the optimal development ("best view") plan is identified, considering the timing of interventions and not foreclosing future pathways.

For the development of our network, this is supported by use of rigorous cost benefit analysis (CBA) which ensures that flexible solutions come "first" and are considered equitably alongside traditional asset solutions. Using flexibility services to postpone conventional reinforcement beyond the RIIO-ED2 period has been used as a generic approach to minimise load related investment.

Engineering Justification Papers (EJPs) have been prepared for every EHV network reinforcement scheme exceeding £2 million with associated CBAs to justify our proposed interventions. Considering wider area load growth and planned developments, strategic EHV network interventions have been proposed to increase long-term cost efficiencies and prevent piecemeal network expansion.

For the HV and LV network, a network optimisation approach has been followed to mitigate all risks from identified issues at minimum cost. The use of permanent LV monitoring is an important first step in the optimisation process, as it allows us to target interventions only when, where and at the proper size needed to avoid stranded and overloaded assets. Our LV monitoring programme overcomes the limitations of smart meter data to take into account unbalances and neutral conductor loading. The use of LV measurements from our proposed LV monitoring programme and smart meters will also allow us to procure larger volumes of flexibility services in HV and LV networks and increase savings.

EJPs have been also prepared for our LV monitoring and service unlooping programme with associated CBAs to justify our proposed interventions.

1 INTRODUCTION

In this Part B of our Load Related Expenditure Annex - Methodology (Annex 3B) we present the methodology used to develop our load related investment proposal as summarised in section 6.1 of our business plan submission and further explained in the other two parts of the Load Related Expenditure Annex describing the proposed investment, ie Load Related Investment Plan (Annex 3A) and Access SCR Impact (Annex 3C).

The objective of this document is to provide transparency and a deeper understanding of how our load related investment decisions were reached by describing the methodologies used to develop the plan and how it is optimised for a range of possible futures.

This Annex covers the following aspects of Appendix 7 – LRE Strategy Guidance of Ofgem's RIIO-ED2 Business Plan Guidance, September 2021:

- Strategic Vision (covered also in Annex 3A)
- Forecasting
- Network Impact Assessment, and
- Optioneering.

Transparency on how the decisions on what is included in our RIIO-ED2 load related investment plan were informed and reached is provided by explaining the data and processes we have employed. Reference is made to how we have followed the RIIO-ED2 guidance and how this has been incorporated in to the "business as usual" ongoing network evaluation and planning processes which are applied on a continual basis to refine our development plans. The whole end-to-end process is described for each voltage level especially detailing approaches that have a material effect on the results.

The structure and content of our document is shaped by the discussions and outputs of the Strategic Investment Working Group's (SIWG) Workstream 1 entitled "Consistency in evaluating forecast pathways". To comply with Ofgem's requirement for consistency in reporting methodologies and the inclusion of significant factors, we have answered the following questions:

- how we have used different forecast pathways to inform our investment requirements
- how intelligence arising from our regional engagement has informed our plan
- how assumptions have been used to translate forecasts in to future true peak demand values for each voltage level, and
- how the benefits of flexibility have been reflected in our load related investment plan.

In accordance with Ofgem's guidance this document also reports on how the regional forecasts on which our investment plans are based compare to the disaggregated national FES and CCC forecasts.

1.1 Annex 3B in relation to other parts of our RIIO-ED2 submission

1.1.1 Main plan

This Annex provides detail and supporting evidence to section 6.1 of our business plan submission.

1.1.2 Load Related Annexes

For clarity and readability, our load related plan and the impacts of the Access SCR are described in three separate, but interlinked parts of our load related plan as shown in Fig. 1.

The Load Related Investment Plan Annex (LRE Annex 3A) describes our proposed programme including cost information on the baseline ex-ante allowance, the investment under uncertainty, savings and benefits of the proposed interventions and the applied DSO processes.

It is expected that the Access SCR will impact on what customers will pay to connect to our network and will change customer behaviour and their requirements for more resilient firm connections instead of accepting flexible connections with associated lower connection costs. The Access SCR Impact Annex (LRE Annex 3C) is closely linked to our load related plan because more load related network reinforcement will be required to accommodate more connections and higher levels of security of supply.

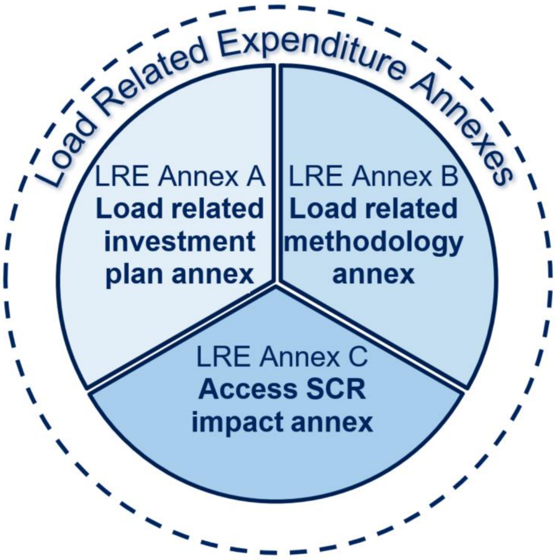


Fig. 1. **Load related Annexes**

1.1.3 Related Business Plan Data Tables

The methodologies are relevant to the following business plan data tables and their corresponding commentaries:

- C2 – Customer funded reinforcement
- CV1 - Primary reinforcement
- CV2 - Secondary reinforcement
- CV3 - Fault level reinforcement
- CV11 – IT equipment
- M14 - Drivers
- M19 - DSO
- M20 - LCT

1.1.4 Other Related Documents

The load related expenditure plan methodology described in this Annex references the following other Annexes:

- DSO Transition Plan – Annex 2
- Load Related Expenditure, Investment plan – Annex 3A
- Load Related Expenditure, Access SCR Impact – Annex 3C
- Network Visibility Strategy – Annex 4
- Enabling Whole System Solutions – Annex 6
- Major Connections Customers Strategy – Annex 16
- Costing and Benchmarking – Annex 20
- Data Strategy – Annex 21
- Digitalisation Strategy – Annex 23
- Innovation Delivery Plan – Annex 24

1.2 Overview of load related investment plan

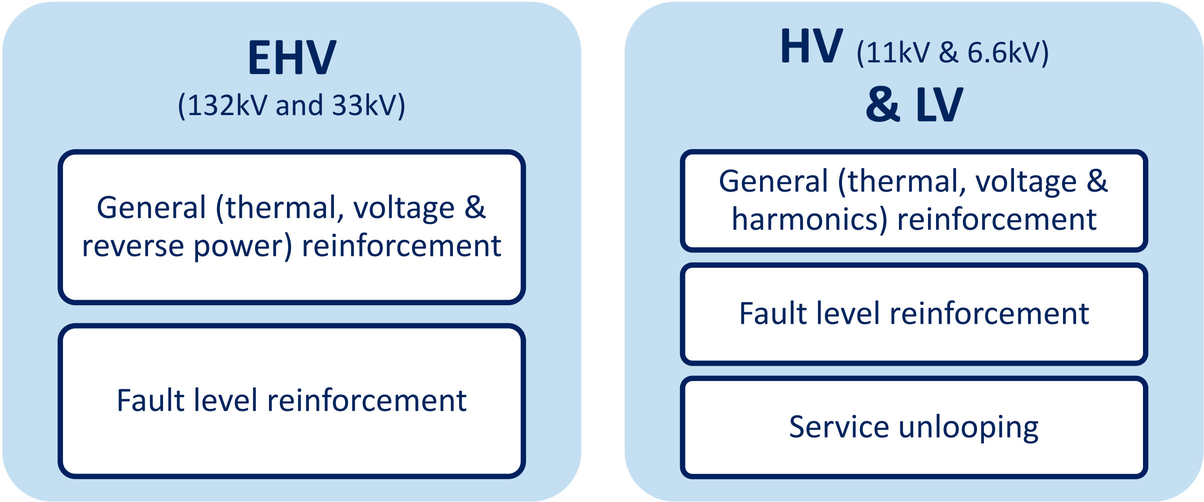


Fig. 2. Load related investment categories

This methodology relates to all components of our RIIO-ED2 load related investment plan as shown in Fig. 2. It describes how named schemes are identified for EHV load related and fault level reinforcements due to the scale and complexity of the work involved. It also describes how reinforcement of our HV and LV networks is considered in terms of programmes of work based on our experience with specific interventions identified during the RIIO-ED1 period. We also cover in our LV reinforcement plan interventions at customers' service points necessary for the safe accommodation of their connection of local carbon technologies (LCTs).

1.3 Overview of investment planning process

A high-level view of the whole end-to-end systematic process we use to identify assured network development needs is shown in Fig. 3.

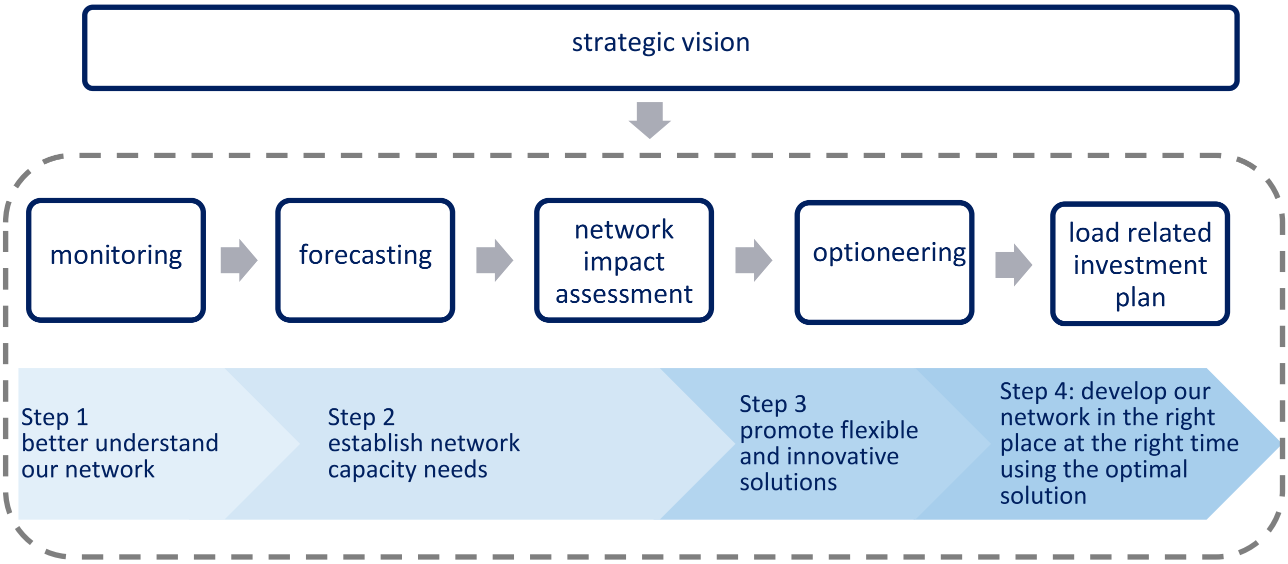


Fig. 3. High level load related investment planning methodology

Following Ofgem's framework guidance, our methodology starts from the monitoring and forecasting components that are required as inputs for the network impact assessment and optioneering components, which in turn inform our load related expenditure plan. The whole methodology is underpinned by our strategic vision for load related investment, which can be delivered by a four step action plan that is overlaid on Ofgem's framework guidance.

Monitoring demand and generation across all voltage levels and using smart meter data is the key first component of our methodology to better understand our network. Expanding our visibility downstream primary substations will allow us to enhance our forecasts, expand flexibility service market to lower voltages and optimise network planning. Forecasts of credible futures are an essential next methodology component as customers' requirements are expected to continue to change within an evolving energy system influenced by Net Zero targets. These alternative views of the future allow us to prepare for a range of eventualities including different levels of low carbon technology uptake. Analysis of demand and generation forecasts informs our understanding of where our network will have sufficient capacity and how this varies for each scenario.

Where we identify potential network constraints, we consider mitigation options based on their location, magnitude, nature and timing dependencies. Although a comprehensive cost benefit analysis may be the final step in our RIIO-ED2 planning process, all decisions are reviewed and may be revised in advance and throughout the progression of each development project.

All steps form part of the ongoing processes using standard network data to reach consistent views of our network capacity as reflected in our standard reports which are published to support our customers as shown in Fig. 4. Relevant network planning data is made available to external stakeholders in a digitised and open form to permit their further analysis to extrapolate network capacity reporting including that in our Distribution Future Electricity Scenarios (DFES)[2], Regional Insights/Network Development Plan report and heatmaps. The manner in which the data from this modelling was made available to other stakeholders is in line with Data Best Practice guidance and principles.

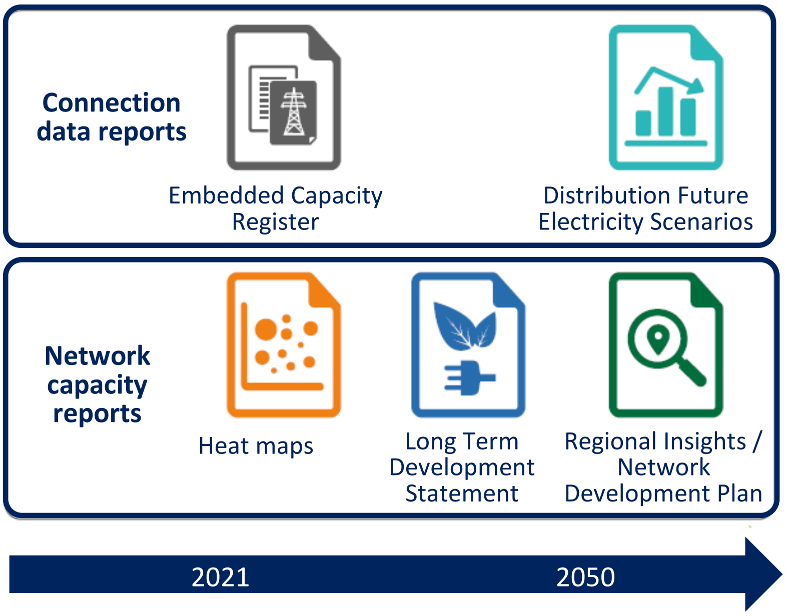


Fig. 4. ENWL network data and capacity publications

[2] Electricity North West, Distribution Future Electricity Scenarios (DFES). Online: www.enwl.co.uk/dfes

1.4 Document structure

This document comprises five further main sections which follow the four high level steps of our investment planning:

- Section 2 presents our strategic vision for an economic and risk averse network development that facilitates the transition to Net Zero whilst protecting customers from cost inefficiencies,
- Section 3 presents how a) our existing monitoring capability has been used to inform our load related expenditure plan; and, b) our planned monitoring capability will allow us to facilitate flexible service market at lower voltages, optimise network planning and recalibrate during RIIO-ED2 to meet the objectives of our strategic vision for load related investment,
- Section 4 outlines the basis and development of the regional scenarios that have informed our load related investment plan,
- Section 5 explains how we assess the impact on our network of forecast electrical requirements, drawing out the differences between voltage levels, and
- Section 6 presents the solutions we apply at each voltage level including flexibility and discusses our decision-making processes. Given the forecast scale of our proposed service unlooping programme, this is briefly presented within this section, but the associated costs and our approach are presented in more detail in a dedicated Engineering Justification Paper (LRE EJP 8).

2 STRATEGIC VISION

2.1 Objectives and action plan

Our strategic vision underpinning our RIIO-ED2 load related expenditure is aligned with the overarching outputs of our main business plan and defined by three objectives, which are:

i. to make sure that our network will not be a barrier to Net Zero,
ii. to implement an efficient and economic network development, and
iii. to manage uncertainties in a transparent manner.

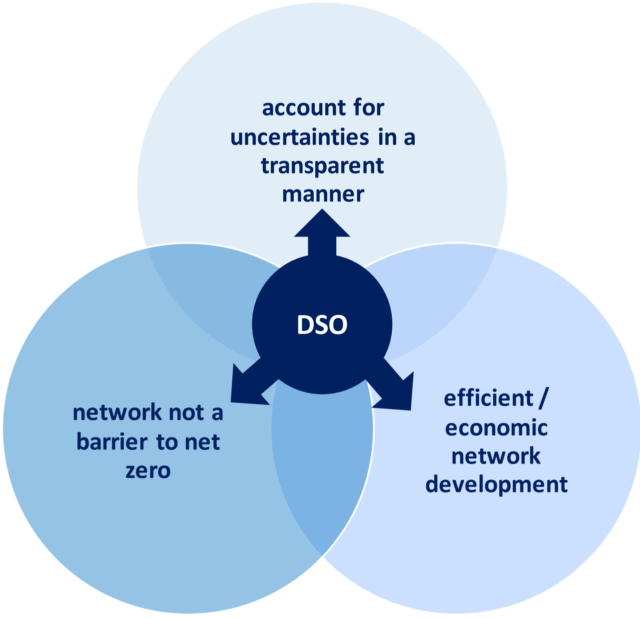


Fig. 5. Our RIIO-ED2 strategic vision with a DSO focused on market development in the centre playing a key role to meet the main three objectives.

In order to meet these objectives, our action plan for load related network investment in RIIO-ED2 is driven by the activities of distribution system operation (DSO) with a focus on flexibility services and energy efficiency markets as shown in Fig. 5. Our DSO based action plan for load related investment comprises four steps listed in Table 1.

This action plan ensures that our strategic vision follows through in our end to end investment decision making.

As a first step of our load related strategic vision action plan we will better understand our network through increased visibility and analysis of big monitoring data. Next, we will establish network capacity need with more accuracy and in greater detail through the enhancement of our forecasts using Net Zero compliant scenarios based on the latest policies and stakeholder input. Our network development plans will continue to be considerate of all scenarios so as to not foreclose future pathways to Net Zero. Having establish the capacity requirements, in step 3 we will promote opportunities for flexible services using the "flexibility first" approach as described in our DSO Transition Plan. We will also promote innovative solutions and energy efficiency as additional ways to help us establish local energy markets and maximise savings for network customers.

Our final step is to develop the network in the "right place" and at the "right time", not only to avoid stranded or overloaded assets, but importantly also to implement cost efficient strategic network interventions that facilitate the transition to Net Zero and avoid piecemeal network expansion. More information on the initiatives and the enabling data corresponding to each of these four steps are shown in Table 1.

Table 1: The action plan to meet the objectives of our strategic vision for load related investment

Load Investment Strategic Vision Action Plan		
Steps	Initiatives	Enabling Data
Step 1: better understand our network monitoring	• Deliver greater network visibility through: ○ Expansion of network monitoring including neutral currents and power quality ○ Integration of Smart Meter and other third-party data sources • Analysis of measurements to understand impacts of new customer behaviours including changes in the time of day and year that energy is consumed and produced	• raw measurements, time sequence loading data and consumption profiles
Step 2: establish network capacity needs forecasting Network impact assessment	• Deliver granular forecasts and undertake network impact assessments ○ Develop DFES forecasts to quantify uncertain Net Zero future pathways ○ Develop LTDS/ Network Development Plan cognisant of all Net Zero compliant scenarios to not foreclose credible alternative pathways	• Distribution Future Electricity Scenarios (DFES), • Long Term Development Statement (LTDS), • Network Development Plan (NDP)
Step 3: promote flexible and innovative solutions optioneering	• Deliver connect and manage approach at LV • Deliver flexibility first to reduce costs, defer costs and mitigate risks • Deliver flexible solution options including flexible connections/ANM • Deliver heatmaps enabling customers to connect in locations with favourable network conditions • Signpost network needs to promote opportunities bolstering flexibility services/energy efficiency market and facilitating third party solutions provision and innovations • Promote and deliver energy efficiency to reduce network loading	• heatmaps, • flexibility services / energy efficiency tenders, • market operation data
Step 4: develop our network in the right place at the right time using the optimal solution load related investment plan	• Use flexibility services to manage uncertainty, and only install new assets when there is high certainty of the needs and little risk of stranding • Apply fully integrated strategic planning for efficient network development, avoiding piecemeal network expansion • Evaluate intervention options always factoring in asset condition and connection requirements • Prioritise vulnerable customers and worst served customer needs	• market operation data, evaluation tools and outcomes

3 MONITORING

The first step in our action plan of the strategic vision for load related investment is to better understand our network not in terms of its assets, but in terms of customer behaviour and needs. Our customers are prosumers that can consume and generate electricity, benefit ting from access to whole system electricity markets. To improve our understanding of customer behaviours, local loading and inform our forecasts, it is critical for our network planning to expand visibility through smart meters and targeted monitoring at lower voltage levels and make best use of the measurements in forecasting and planning.

In the following subsections we first describe how our existing visibility of the EHV network has been used to inform our RIIO-ED2 Load Related Expenditure (LRE) plan. Then we present how moving forward our proposed permanent LV monitoring programme and access to smart meter data will help us meet the objectives of our strategic vision for RIIO-ED2. Further detail is provided in our Network Visibility Strategy (Annex 4) supported by our Data Strategy (Annex 21) and Digitisation Strategy (Annex 23).

3.1 Existing capabilities

Measurements of electricity demand across substations and distributed generators are required to inform demand forecasts and distribution network planning. For all GB DNOs primary substations are currently the last point of permanent monitoring. Until now this has allowed DNOs to report and forecast network utilisation per substation only for the EHV part of their network.

For our EHV network we apply our ATLAS methodology for the automated processing of half hourly through year measurements across all EHV substations and distribution generators with available measurements. Combined with estimates for smaller non-monitored generators, the developed tools have allowed us since our first DFES in 2018 to improve our understanding of EHV network loading, associated capacity headroom and demand diversification across associated voltage levels. These processes have enabled us to make the best use of EHV and HV monitoring data to produce the DFES scenarios that directly inform our RIIO-ED2 LRE plan.

For our HV and LV network, the absence of measurements at lower voltages has directed us to make use of best available techniques to inform our RIIO-ED2 LRE plan. More specifically, we have combined our DFES forecasts of LCTs at lower voltages with load allocation techniques in our Future Capacity Headroom (FCH) model, where measurements from the head of all >3,000 HV feeders in our network are allocated down to secondary substations. More information on how our FCH model makes best use of monitoring and local DFES forecasts can be found in section 5.3.

3.2 Expanding visibility in RIIO-ED2

Our strategic vision for load related investment in RIIO-ED2 requires us to better understand our network in step 1 before establishing our network capacity needs through forecasting and network impact assessments (step 2). As we expect unprecedented volumes of EVs and other LCTs to increase the loading of our HV and LV network during RIIO-ED2, there is a need for us to expand our visibility downstream from primary substations to understand the loading across all voltages of our network.

By expanding our visibility we can establish the control logic feedback loop of our strategic vision that allows us to refine our plans to make sure that we meet the objectives of our RIIO-ED2 load related investment as described in section 2.

To implement our strategic vision we need to use monitoring data below primary substations in HV and LV networks. This data will allow us to understand network utilisation at lower voltages and enhance our forecasts by increasing their granularity and making them more representative of customer behaviour and local loading patterns. By doing that we can:

- target interventions only where and when needed,
- avoid interventions being made too early based on cautious assumptions,
- facilitate flexibility services in LV networks that are targeted in terms of location, as well as detailed technical requirements, eg seasonality, time duration and days required. This will allow a wider range of customers to participate and at the same time create a more competitive market to the benefit of our customers,
- facilitate flexible connections and evaluation of constraint parameters based on actual seasonal and daily usage patterns, and
- optimise the network planning approach by identifying the most cost efficient and at the same time risk averse interventions on a case specific basis (see section on Network Impact Assessment for secondary networks).

As highlighted in our Data Strategy, our customers and stakeholders can also benefit by having access to loading and flexibility service requirement data across all voltage levels and the whole of our network. With this data they will be able to better inform their decisions and action plans to decarbonise and benefit from flexible service and energy efficiency opportunities.

Our proposal for monitoring is to use permanent LV monitoring capable of measuring loading across all three phases and earth return currents together with smart meter data. The LV monitoring programme is presented in more detail in our LRE EJP9 – "LV monitoring" and it is required to cover the gaps of using purely smart meter data. Importantly, our LV monitoring programme can measure neutral conductor loading that cannot be captured by smart meters, as well as to bring additional benefits including cost efficiencies from capturing power quality measurements and from implementation of a "connect & manage" approach that releases capacity for more LCT connections.

We propose that 80% of the LV monitoring programme needs to be delivered in the first two years of RIIO-ED2. This way we can maximise the benefits from its utilisation, resulting in lower load related expenditure as explained in the associated EJP and avoiding at the same time any risks from a delayed roll out of smart meters. It should be noted that as also supported with CBA in the EJP, a permanent monitoring approach also prevents the more expensive and labour intensive option of temporary monitoring where engineers will need to take more frequent on-site measurements than in RIIO-ED1.

4 FORECASTING SCENARIOS

4.1 Overview

A wide range of long-term forecasting scenarios for electricity demand and distributed generation have been used for the development of our RIIO-ED2 load related investment programme. The forecasting components that are described in this section are shown in Fig. 6 and are in compliance with Ofgem's framework for the reporting of the methodology underpinning RIIO-ED2 load related investment programmes of all DNOs.

Following RIIO-ED2 guidance, this section explains how the Central Outlook scenario from our DFES is identified as the highest certainty "best view" scenario. As such, the Central Outlook scenario supports our RIIO-ED2 load related investment ex-ante plan and as a central and average risk scenario it also supports the transition to Net Zero carbon beyond RIIO-ED2.

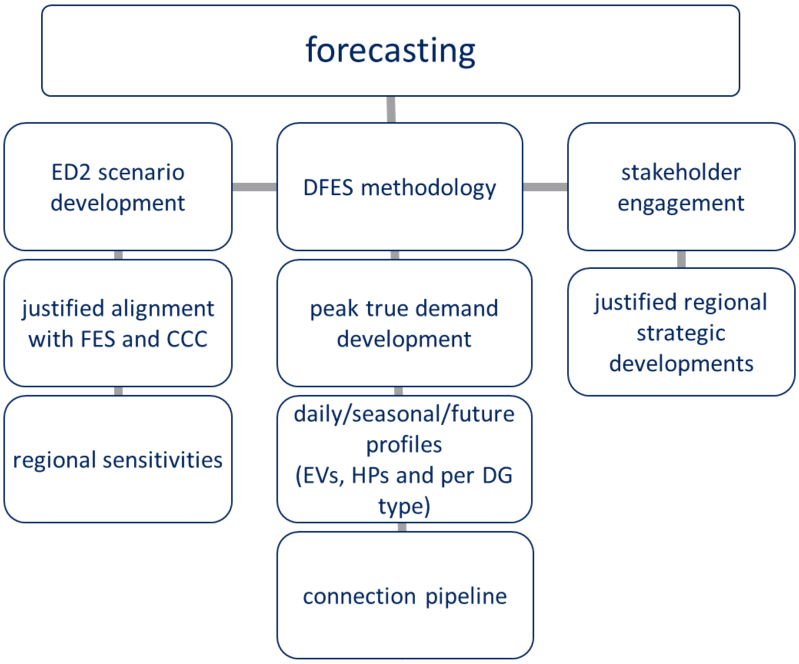


Fig. 6. The forecasting components from Ofgem's reporting framework for the RIIO-ED2 load related investment methodology

Lower certainty scenarios are used as part of a sensitivity analysis to quantify the minimum-to-maximum range of RIIO-ED2 load related investment. The sensitivity analysis also reveals the narrow range of investment needs between Central Outlook and other Net Zero compliant scenarios in RIIO-ED2.

This section first summarises all RIIO-ED2 scenarios used to support our load related investment programme and explains their link with DFES and the standardisation of the ESO FES and DFES. Next, how our scenarios comply with RIIO-ED2 guidance is explained. This process reveals why our Central Outlook, driven by national policies and local factors, is the highest certainty scenario. It also explains which other scenarios are compliant, including a comparison with FES and CCC forecasts from ED2 guidance.

We also explain how the various demand components affect peak demand and how the adopted modelling and stakeholder engagement captures local trends to allow network planning to target investment only where and when needed. Finally, a sensitivity analysis is carried out focusing on the range of uncertainty if local policies accelerate decarbonisation to meet Net Zero carbon before 2040.

Our full range of RIIO-ED2 scenarios is based on 2020 DFES, which are the latest published. Even though our 2021 DFES has not yet been finalised and will be published in late December after our final submission, in the sensitivity analysis presented at the end of this section we will discuss why our draft 2021 forecasts a) should not affect the proposed ex ante allowance and b) are well within the quantified investment under uncertainty.

Further information on the methodologies we employ in the creation of our DFES and the 2020 DFES forecasts is available on our website.

4.2 RIIO-ED2 Scenarios

Following the whole system FES standardisation process developed in Worksteam1B Product 2 of the ENA Open Networks project, four of our DFES 2020 scenarios (SP, ST, CT and LW) share the same scenario framework, names and high-level assumptions with ESO FES and all other DNOs' DFES. As shown in Fig. 7, our DFES also includes Central Outlook (CO) as a "best view" fifth scenario in accordance with our ATLAS methodology, ie using average/central assumptions within the common scenario framework axes.

Our forecasting approach is not a simple split of national forecasts, but instead uses our detailed knowledge of our region gained from engagement and cooperation with local stakeholders. Our bottom up forecasts and subsequent network development plans are refined to meet the detailed needs in each part of the region taking into consideration assured local developments and Local Area Energy Plans.

Even though stakeholder engagement has allowed us to model evidence-based local plans in DFES, it has also revealed that local policies are not yet in place to accelerate decarbonisation to meet Net Zero carbon targets before 2040. Therefore, all five scenarios in our 2020 DFES are driven by national policies and local factors reflected through our cycle of engagement with local stakeholders and ATLAS bottom up forecasting methodologies. Apart from the SP scenario, all our other four scenarios meet the UK government's 2050 Net Zero carbon target. Specifically, CO, CT and ST scenarios meet Net Zero by 2050 and our LW scenario meets the target by 2045.

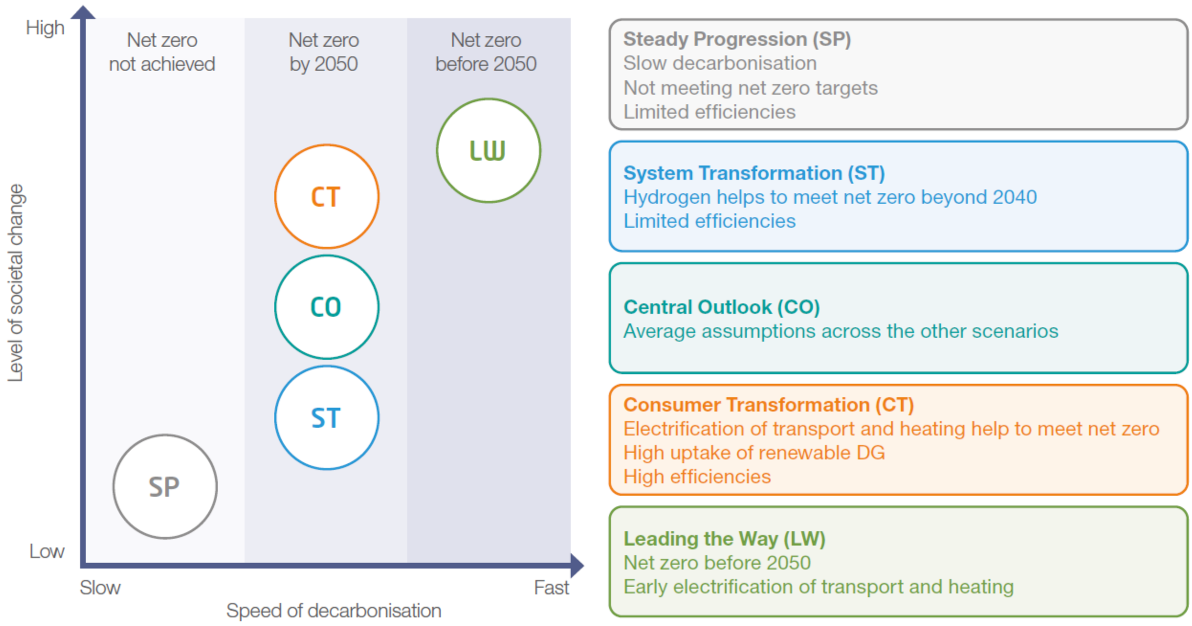


Fig. 7. Electricity North West DFES 2020 scenarios

To quantify the range of uncertainties if parts of our region accelerate decarbonisation to meet Net Zero carbon targets before 2040, three alternative versions of the CO, CT and LW scenarios have been also produced to support the development of our RIIO-ED2 business plan. More specifically, these three scenarios consider accelerated decarbonisation through the electrification of heat and transport in the form of increased volumes of EVs and heat pumps.

All eight scenarios, either from our DFES, or their corresponding accelerated decarbonisation versions were considered to:

- identify which scenarios comply with RIIO-ED2 guidance;
- identify and explain which scenario has the highest certainty and why; and,
- show the range of RIIO-ED2 investments and define the assumptions for the top and bottom of the range.

4.2.1 Forecast parameters

We forecast the following parameters for each scenario up to 2050:

- LCT numbers
    - EV volumes
    - Heat pump volumes
    - Generation and storage capacities
- Electricity demand
    - Energy consumption
    - True peak demand

To forecast electricity demand we follow our bottom up ATLAS methodology. In our approach we use half-hourly through year resolution, input data that can go down to post code level, measurements that have been cleansed using machine learning techniques, information of stakeholders' planned developments and consumer choice models for the LCT uptakes. A simplified illustration of the ATLAS methodology is shown in Fig. 8.

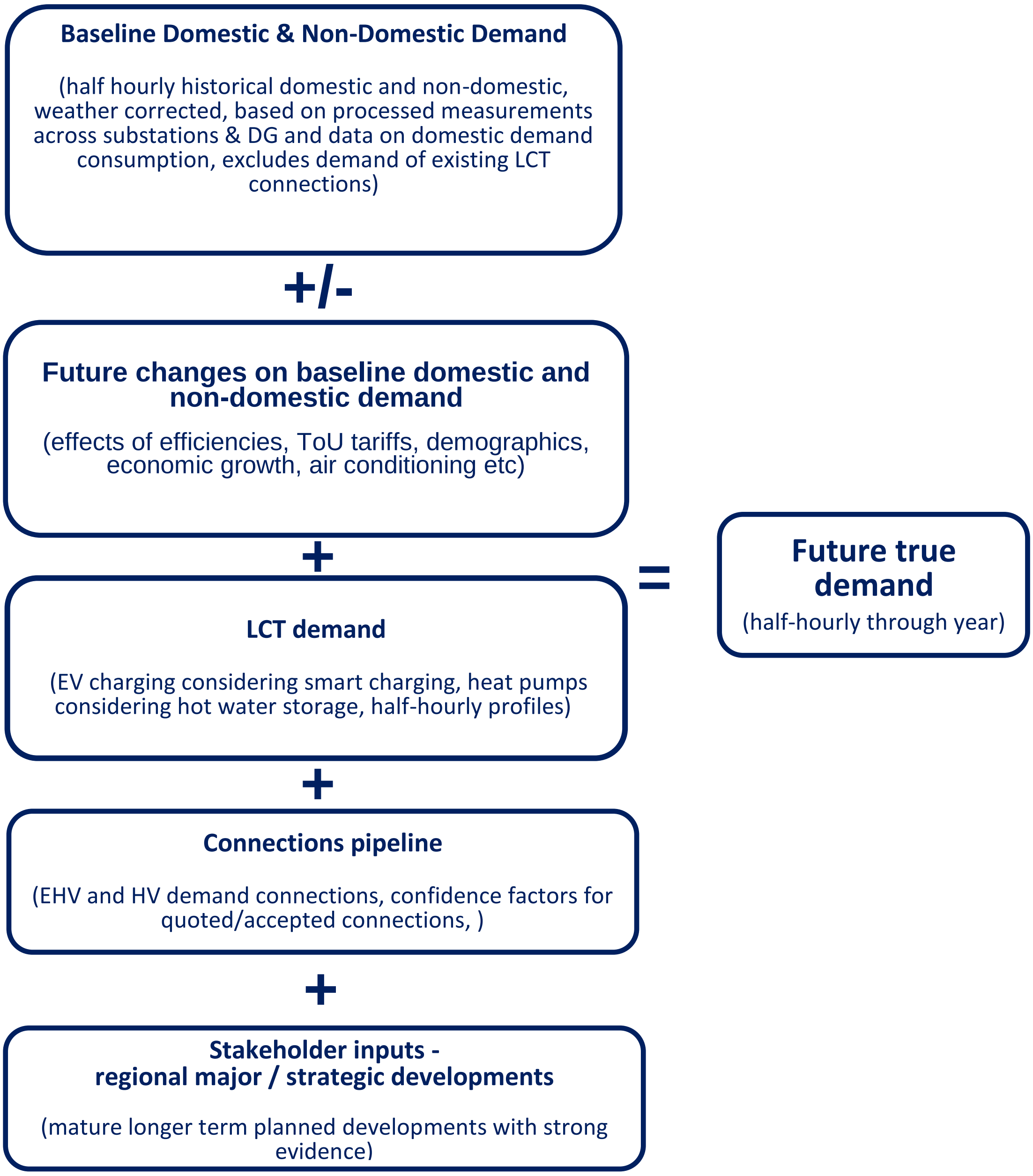


Fig. 8. Simplified demonstration of ATLAS methodology to forecast half-hourly through year true demand

True demand is the demand that needs to be supplied at a local level if local generators are not exporting, e.g. due to maintenance or low wind for wind farms. Fig. 8 shows a high-level view of how the different demand components of our bottom-up ATLAS methodology are aggregated to assess the future half-hourly through year demand per substation. The future demand is built on the baseline (existing) demand that is weather corrected and is calculated using automated processing of half-hourly measurements from substations and DG units.

Demand from LCTs, ie EV charging and heat pump connections, connections pipeline and stakeholder major planned developments are considered as incremental components that add demand as shown in the bottom three components of Fig. 8. However, future demand can be reduced due to different types of efficiencies, economic recession, local demolition rates and other factors that are modelled in the second component that accounts for changes on the baseline domestic and non-domestic demand that can not only increase, but also decrease demand. As shown later in this section, the baseline peak domestic and non-domestic demand decreases across all scenarios due to effects of efficiencies and time of use (ToU) tariffs.

Forecasting true demand at local level is particularly important in distribution networks for numerous reasons:

- Local demand is less diversified than at the national transmission level, eg in FY20 the sum of individual primary substation peaks in our South Manchester group was one third more than the peak demand for the group observed at the transmission interface. Diversity is even lower in the HV and LV parts of our distribution network that are closer to customer points of connection.
- Distribution network security of supply assessments in accordance with EREC P2/7 (a licence condition requirement) require consideration of local true (gross) demand as a minimum. An allowance for the contribution of local generation to security of supply is modelled following EREC P2/7 considering that local generation is less diversified as we move to lower voltage levels. The allowance is typically significantly less than the sum of the generators' rated capacity values.
- Demand forecasts produced with a transmission or capacity market focus, eg ESO FES, can be inclusive of the diversified effects of small local generators that appear to reduce the consumption on distribution network customers because they are used to determine the level of demand that needs to be supplied via the transmission network, rather than the local distribution network.

4.2.2 Domestic and Industrial & Commercial demand effects on peak demand

The current split of peak true demand forms the basis for developing future changes in domestic and Industrial & Commercial (I&C) demand to be reflected in our forecasts. Our information on individual customers and which substation they are connected enables us to develop precise understanding of the split between domestic and I&C customer demand.

Fig. 9 shows how the winter afternoon demand on our network breaks down into different customer and usage types. Even though domestic demand accounts for around one third of electricity consumption in terms of energy in MWh, it accounts for approximately half the winter peak demand, mainly due to the use of domestic electric heating coinciding with the time of overall peak demand. It should be highlighted that our DFES peak demand assessments are based on local half-hourly demands informed by local measurements across substations and generators. Using historical half-hourly domestic and I&C demand values allows us to build local and per asset forecasts more accurately than if we took a national averaging approach.

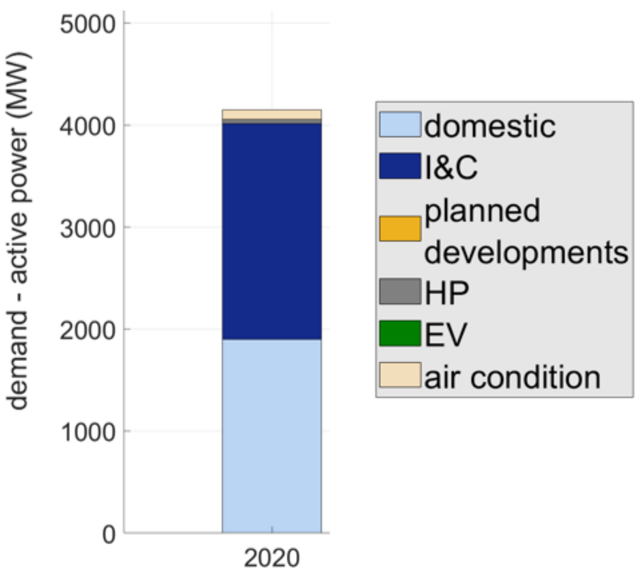


Fig. 9. Decomposition of demand for the average December 2020 4.30-5.00 pm half-hourly period. Weather corrected values

4.2.3 Modelling true peak demand

To understand the effects of LCTs on future local peak true demand, a critical modelling aspect beyond LCT volume uptakes is to consider how changes in future behaviours and technical characteristics will affect the way and times that these LCTs will consume electricity. We do this in practice through the use of diversified LCT profiles which show how EV charging and heat pumps can, on average, affect demand at different times through the day, as well as how these profiles can change from 2020 to 2030.

In addition to modelling local factors (e.g. building stock and planned developments of local stakeholders to capture differences across our region) it is critical to model each demand component using half-hourly measurements and data. This is necessary to quantify how domestic, I&C, EV charging and heat pump demand can affect local peak load or even shift the time of peak demand to a different time within the day or month/season.

4.2.4 EV profiles and smart charging

Our forecasts are built using diversified average charging profiles which are different for each year as smart charging and customer behaviours evolve as illustrated in the detailed data included in our DFES workbook[3]. Fig. 10 shows examples of the average per EV daily demand profiles for 2020 and 2030 used in our Central Outlook scenario.

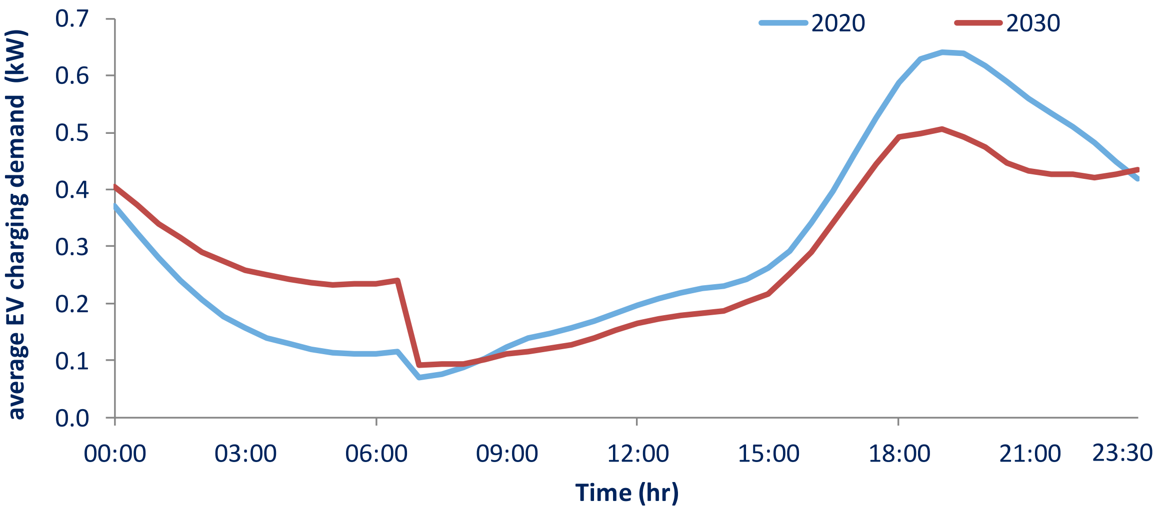


Fig. 10. Average per EV charging profile considering diversified effects of EVs on EHV and HV networks (Central Outlook scenario)

The 2020 profile is based on the results of analysis by Element Energy of over 10 million real life charging events (source: ESO study) and composite modelling taking into account different types of charging, ie domestic, destination, en-route and commercial for vans. The profiles consider the diversity at EHV and HV networks and therefore a peak demand per EV is below 0.7kW when most domestic chargers are expected to be at 7.5kW and higher by 2030 and commercial chargers at much higher capacities.

The 2030 demand profile considers the effects of smart charging which sees the demand at the time of traditional distribution peak load in the afternoon reduced by over 25%. In practice smart charging

[3] https://www.enwl.co.uk/dfes

is expected to increase the amount of charging at different times of the day and overnight for domestic customers. Importantly, as for all demand components, the EV profiles used in our ATLAS methodology are combined with half-hourly through year demand profiles of local substations.

Therefore, EV charging has different effects on individual substations depending on:

a) the time of underlying demand peak;
b) the mix of domestic and non-domestic demand per location as this can affect the future baseline demand profile, and
c) the uptakes of other LCTs (heat pumps) and technologies (air conditioning) as these are also using corresponding half-hour profiles that will interact with EV profiles.

It should be highlighted that local effects of EV charging are less diversified and our analysis considers regional characteristics, e.g. access to off-street parking for domestic charging and travel data/location of en-route chargers for rapid charging. More purely battery EVs on the roads can increase per EV contribution on peak demand in the short term (2020-2023), but smart EV charging is reducing it in the longer term (2024-2030). This is shown in Fig. 11, where EV effects on winter afternoon peak demand are presented for the half-hourly period commencing at 4.30 pm. The EV effects are shown for each year from 2020 to 2030 for the CO (Central Outlook), CT and LW scenarios. As for all other modelling assumptions, Central Outlook uses the highest certainty assumptions and medium smart charging levels compared to high levels for the other two scenarios. This is on the basis that the shifting of demand through smart charging will not be initially driven by needs of distribution networks, but by when there are high levels of generation, ie when the wind is blowing, and wind power levels are high. It is expected that generator price signals will be stronger due to the greater price of energy compared to network signals based on an economic alternative to network reinforcement.

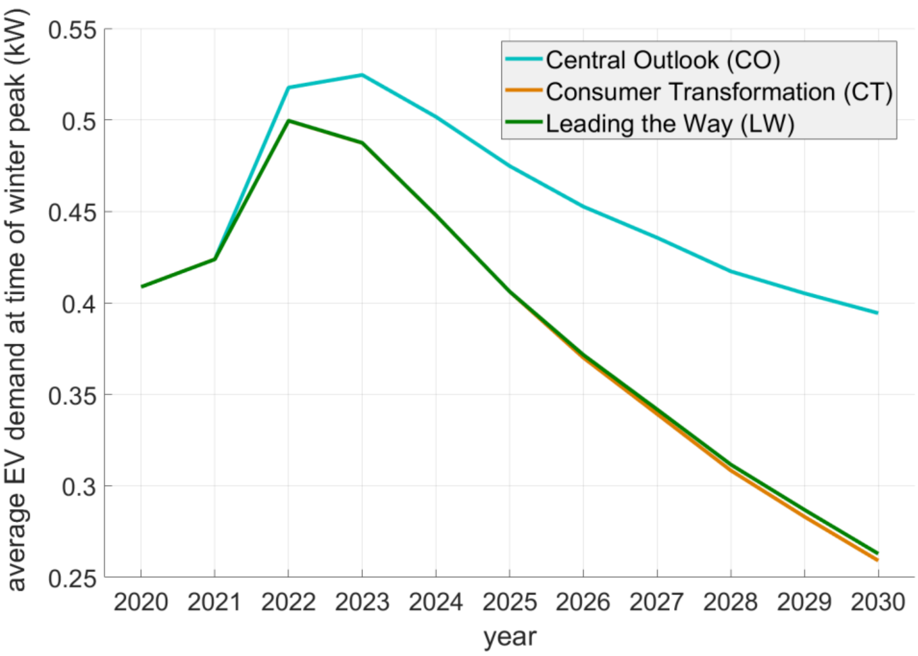


Fig. 11. Average per EV effects on winter afternoon demand (4.30-5.00 pm period)

4.2.5 Heat pump profiles

Focusing on the effects of heat pumps on peak demand, again these can be best demonstrated using corresponding daily demand profiles. Fig. 12 shows the average per domestic heat pump daily demand profiles for December (winter demand) and for 2020 and 2030 used in our Central Outlook scenario.

Similar to EV charging, the peak demand in the heat pump profiles (less than 1.4kW in 2020 and reduced by over 40% by 2030) is much lower than individual heat pump peak demand (typically from

5 to over 15kW). This is because the profiles are used to represent average usage across a large population in which devices are used at different times of the day. The 2020 profiles are based on original profiles from trials and simulations carried out in our Demand Scenarios NIA project (source: Delta EE and Imperial College). Our original profiles were then post-processed by Element Energy to model hot water storage, ie demand shifted from periods of peak load to the overnight and mid-afternoon troughs when demand for electricity is typically lower.

To accurately assess the electricity demand requirements for heat pumps, it is first necessary to assess the need for heating based on the actual building stock. Our analysis models the actual building stock which gives a much more accurate regional assessment of local heating demand. Having assessed the heating demand, our next step is to convert this to electricity requirements (in MWh) based on the heat pump coefficient of performance (COP). It should be highlighted that our analysis has considered higher COP factors than the ESO FES, ie 2.6 vs 2.16 for air source heat pumps and 3 versus 2.59 for ground source heat pumps, based on half-hourly weather corrected values which are more representative than the extreme cold scenario. Our assumption results in a lower impact on electrical energy and peak demand.

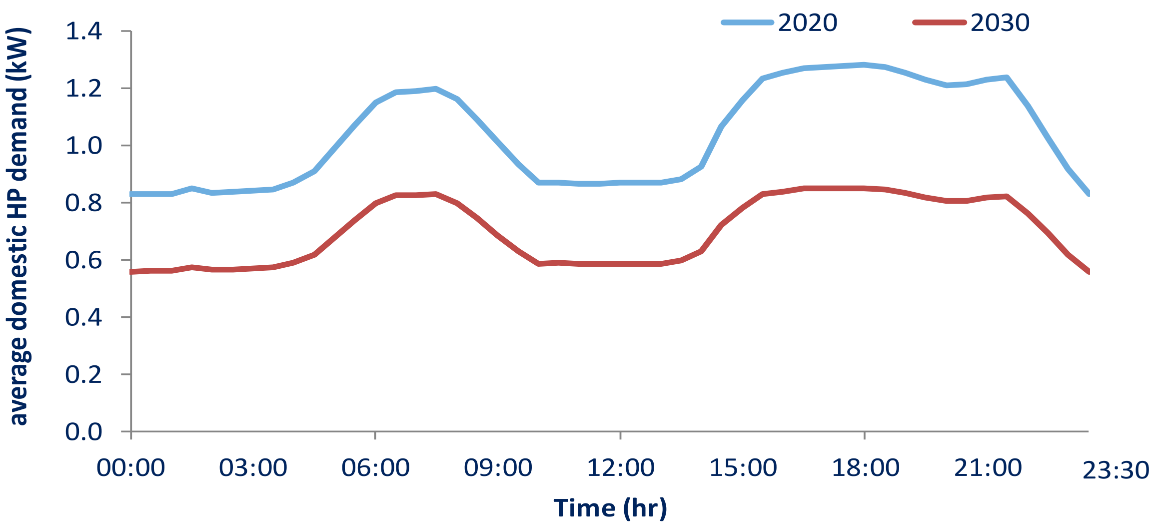


Fig. 12. Average demand profile considering diversified effects of heat pumps on EHV and HV networks in 2020 and 2030 (Central Outlook scenario).

4.2.6 Growth of electricity consumption per customer

During the last decade we have observed an around 10% reduction of overall electricity consumption in our network. This has been mainly driven by economic transformation with high consumption industrial processes ceasing, but also by all types of efficiencies including more efficient street lighting, replacement of energy intensive domestic appliances, heating insulation improvements etc.

For the forthcoming years, our stakeholder engagement has shown that we should be expecting demand growth during RIIO-ED2 from major / strategic planned development in specific network locations. These are mature projects as presented in section 4.3.2 and they have been identified as having strong central/local government backing, secure funding and ongoing development progress. Together with EHV and HV demand connections, these developments are expected to increase, during RIIO-ED2 period the demand supplied by the EHV network at specific locations.

Apart from these developments, the second key factor that we expect to drive electricity consumption (energy demand) growth is LCTs and mainly EVs. Based on our Central Outlook ("best view") forecasts, we expect that a quarter of our customers will have an EV by the end of RIIO-ED2. The required EV charging will result in an additional electricity demand from the existing baseline.

To understand the electricity consumption growth of the baseline demand that is mainly supplied by the HV and LV network we need to see our forecasts excluding these planned developments that mainly increase the load of the EHV network. This is shown in Fig. 13 for the average per customer electricity consumption based on our Central Outlook ("best view") scenario. This has been calculated as the overall MWh per year consumption divided by the total number of customers in our area and can be considered as a simple metric that is representative of annual electricity consumption growth in our region.

LCTs (EVs and heat pumps) and planned developments are expected to cause electricity consumption to grow. Fig. 14 shows that baseline electricity consumption will potentially fall by the end of RIIO-ED2 without LCTs and planned developments. The forecasts shown in this figure correspond to average consumption per customer in MWh/customer for our Central Outlook ("best view") scenario. Whilst baseline demand reduces by 4% from FY20 to FY28, overall electricity consumption increases mainly driven by EVs and major developments supplied by the EHV network to reach an around 3.5% increase from where it was ten years ago.

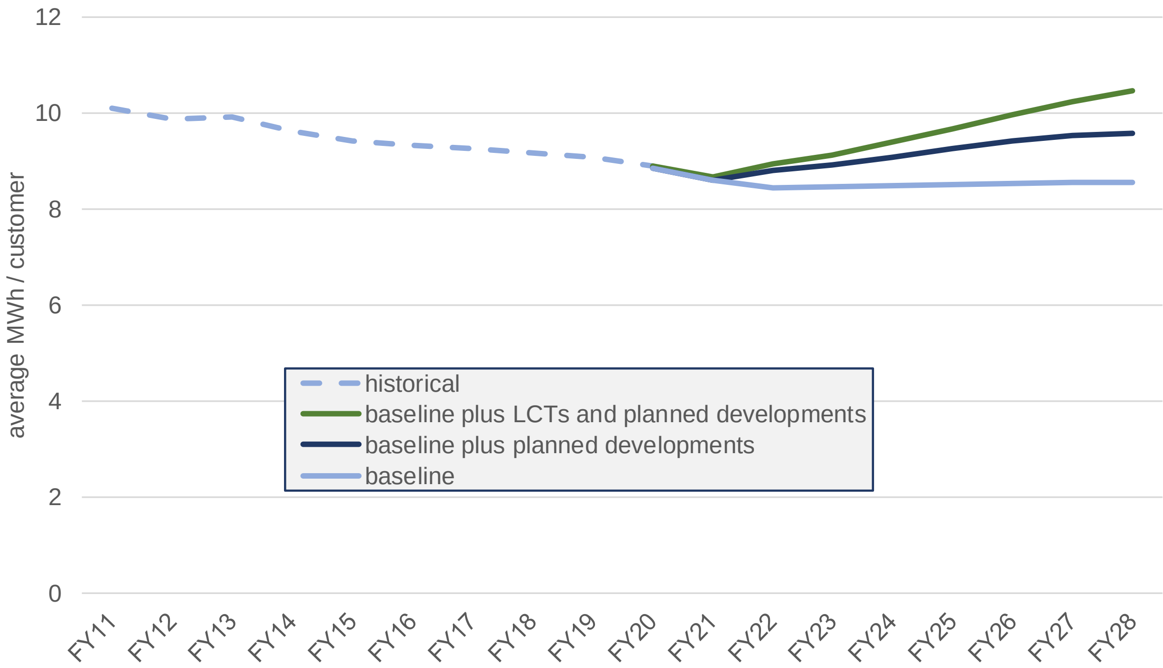


Fig. 13. Average electricity consumption per customer in our license area.

4.3 Stakeholder engagement

Our engagement with local stakeholders including local authorities (LAs), customers, energy communities and investors provides valuable inputs to our ATLAS forecasting methodology used to produce the DFES. As shown in Fig. 14, these inputs include both data provided directly by stakeholders but importantly also how implications of our network development affect stakeholder decisions and connection behaviour.

At a high level, the DFES inputs from local stakeholders can be grouped as:

- LA decarbonisation policies affecting consumer choice at local level;
- planned developments with associated connection quotes (ie our connections pipeline); and,
- established plans of major developments backed by LAs, which are more efficiently accommodated on to our network by holistic and strategic investment.

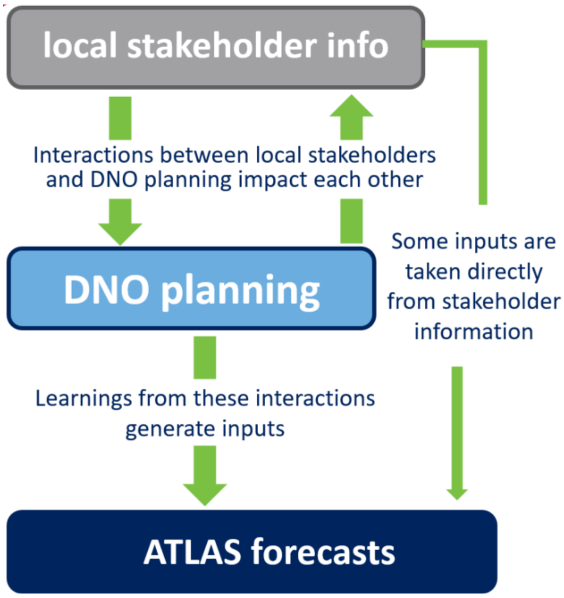


Fig. 14. **Local stakeholder inputs to the ATLAS methodology used to produce DFES forecasts**

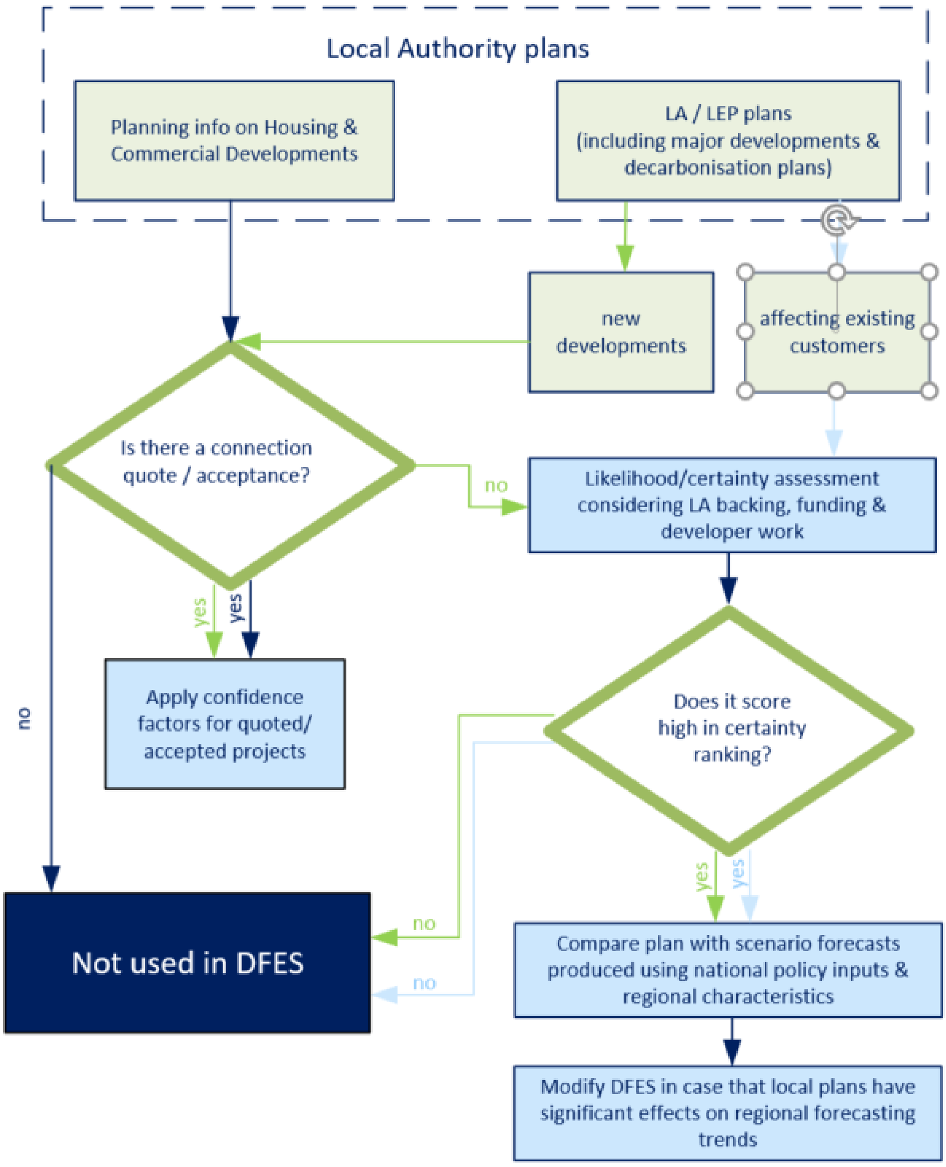


Fig. 15. **Process to model LA and LEP energy plans in DFES**

To model LA and Local Enterprise Partnership (LEP) plans in our DFES we have followed the process shown in Fig. 15. In line with Energy Systems Catapult best practice checklist for Local Area Energy Plans (LAEPs)[4] and Scottish Government draft framework for Devolved Regional and Local (DRL) planning[5], our process identifies realistic and deliverable projects, ie only plans with LA backing, secure funding and ongoing development modelled, by:

- using a consistent and transparent approach, ie ATLAS methodology for connections pipeline with certainty ranking introduced to model major developments,
- considering LAEPs and DRL energy plans, ie developments that are part of LA spatial frameworks and ongoing decarbonisation plans,
- considering the proposed timeline of LAEPs and DRL energy plans and sensitivity of timing, ie modelling demand growth on a year-per-year basis extending beyond RIIO-ED2 to inform strategic network investment, and
- assuring quality using validated models and inputs, ie use historical performance for connection pipeline forecast and detailed stakeholder requirements for major developments.

As shown on the left-hand side in Fig. 15, if there is a quoted or accepted connection offer associated with any of the new developments that are part of the LA's decarbonisation plans, then these are scaled by confidence and included in the DFES, together with any associated LA planning information. As shown on the right-hand side of the same figure, new developments with no associated connection quote/acceptance are further examined via a certainty/likelihood assessment.

Sub-sections 4.3.1 and 4.3.2 focus on the incorporation of our connections pipeline and regional strategic developments, respectively. These are two key areas where stakeholder engagement has influenced the local demand growth in our DFES forecasts and consequently our RIIO-ED2 load related investment programme.

4.3.1 Incorporation of connection pipeline

Our demand growth and DG forecasts (per DG type) include our connection offer and acceptance pipelines for demand and DG projects using confidence factors in accordance with our ATLAS methodology. This process can be summarised as follows for demand and DG projects:

- **for HV and LV demand connections:** historical performance is identified using data from a sample of several thousand quotes, acceptances and energisations of commercial and industrial projects. This data is first used to establish the percentage of quoted connections that are accepted and the percentage of these that go on to energise their connection. We assume that these historic rates are applicable to the future and can be used to scale known volumes of offers to be included in our demand forecasts. These percentages can be considered as a first set of confidence factors which are identified separately for the north and south of our license area. A second set of confidence factors is identified from the analysis of the maximum demand (MD) reached by energised projects, compared to their contracted maximum import capacity (MIC). As might have been expected, the confidence factors for connection offers is less than those for connection acceptances. The two sets of confidence factors are then applied to present offered and accepted demand connection pipelines.
- **for EHV demand connections**: likelihood indices are used based on information provided by customers as well as by our Connections business teams. We examine progression to check where each project is within their development and connections process and importantly consider the expected timeline of energisation and demand growth, as well as the customer

[4] Best Practice for developing LAEP, ESC. Online: https://www.cse.org.uk/projects/view/1369
[5] Scottish Government draft framework for DRL planning. Online: here.

type to assign realistic demand profiles (eg, a Network Rail connection will be modelled using average half-hourly demand profiles from existing railway sites).

- **for DG and grid scale battery storage connections** (EHV and HV): we consider only accepted connections, given that historical analysis has revealed that a large number of connection offers do not progress.

4.3.2 Regional strategic developments

Stakeholder engagement provides valuable input to our DFES and can have a significant influence when we learn of established plans which may require us to strategically invest in network capacity. Regional strategic developments are included in the DFES because such large focussed development hot spots could be at a planning stage but have not applied to us for electrical connections or have a connection offer yet.

Involvement of multiple potential customers in a small area over a short development window means that it is important that we take a holistic view rather than making less efficient piecemeal network interventions. Regional stakeholder developments are only included in our DFES forecasts when we are confident that they are likely to go ahead and we have robust evidence to support this confidence. As part of our certainty ranking shown in Fig. 15 we evaluate various types of justification, i.e. Local Authority plans, national/local funding such as the government's "Getting Building Fund" [6] etc, developer enquiries. The level of justification may vary if we identify other needs in an area, for example asset health or increased connection activity in a neighbouring area.

Fig. 16 shows the Mayfield example of a regional strategic development in our area. Using the certainty ranking this development area has been selected to be modelled in DFES as we have identified secured funding with strong LA and national backing. More specifically, apart from the significant activity shown in the connections pipeline for this area, there are also:

- Local Authority driven developments as part of Greater Manchester Spatial Framework (GMSF) agreement for regeneration of Manchester (GM Strat 7 – North East Growth Corridor);
- HS2 Government backed national infrastructure scheme to develop high speed interconnection between the North and London; and,
- planned University of Manchester re-development programme for the north campuses (former UMIST).

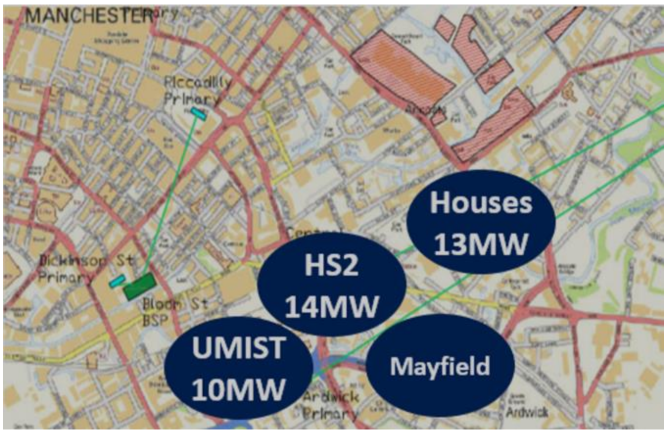


Fig. 16. The Mayfield example of regional strategic development

[6] https://www.gov.uk/guidance/getting-building-fund

The per year demand growth and the planning timeline of several robustly justified local stakeholder plans have been modelled in DFES and the forecasted demand has been modelled in network studies to assess network impacts.

Table 2 lists the regional developments included in our 2020 DFES forecasts. Demand growth drivers are identified alongside the affected network substation location and demand increment. It should be noted that these demand increments should be treated as indicative maximum effects on peak demand, given that our half-hourly forecasting approach determines a more precise effect of each project on local peak demand.

Network intervention has been proposed and justified via individual EJPs for some of the regional strategic developments. These EJPs justify that the proposed strategic interventions can improve cost efficiencies compared to a piecemeal planning approach.

Table 2: Regional strategic development areas

Development Area / Scheme Name	Drivers	Total RIIO-ED2 demand increment	Total RIIO-ED3 demand increment (same substations)
St Cuthbert's Garden Village	Creation of 10,000 new homes in garden village with Housing Infrastructure Fund (HIF) allocation. Includes office, education and retail developments supported by Carlisle City Council (part of Carlisle District Local Plan) and part of UK government's Garden Towns and Villages Programme. Masterplans part A and B completed by Gillespies and Arup respectively.	+12MVA at Morton Park primary	+8MVA
Manchester Eastern Gateway (named schemes: Northern Gateway and Eastlands extension)	Development and regeneration corridor spanning NOMA district, along Queens Park, Ancoats, Central Retail Park, New Islington, Eastlands with Manchester City Council and private developer leads. Key to GMCA economic growth and housing re-development plans with 15,000 new homes resulting in 25MVA demand increase phased from 2022 to 2032 (ED2 demand 12-15MVA). Eastlands SRF: (1) Ancoats, Central retail park and New Islington 1.2m sq ft of commercial space and 3,000 new homes requiring 13MVA of additional demand from 2022 -2026. (2) Etihad Campus sports, retail and arena development: approx. 20 MVA in ED2. Ongoing collaboration with MCFC and New Islington/Manchester City Council.	+45MVA at Queens Park and Eastlands primaries	+10MVA at minimum
Central Manchester – Southern Gateway	Additional new demands in the areas around Manchester Science Park, First Street and Oxford Rd Corridor. Strategic importance to relieve immediate reinforcement in Bloom St area and associated primaries. Existing city centre primaries have 15MVA capacity deficit when considering new accepted connections. Alternative to reinforcements of Ardwick, Moss Side and Victoria Park. Development included in the UK government shovel ready/getting building fund with Bruntwood (Science Park owner) endorsement also received.	+30MVA at Ardwick, Moss Side and Victoria Park primaries	+9MVA
Mayfield development	University of Manchester campus re-development, HS2 terminal & depot forms the GM North Corridor regeneration. Mayfield SRF: 1) 8MVA of capacity required for commercial/office development at Mayfield Depot; 2) 7MVA of capacity for UoM North Campus redevelopment and 3) HS2 capacity of 15MVA. Development included in the UK government shovel ready/getting building fund.	+26MVA at Central Manchester primary	+4MVA

Development Area / Scheme Name	Drivers	Total RIIO-ED2 demand increment	Total RIIO-ED3 demand increment (same substations)
Godley Green Garden Village	Creation of 3,000 new homes proposed in GM Spatial Framework and supported by Tameside council. Tameside council agreed to draw £10m from UK government Housing Infrastructure Fund. Developer has secured additional Homes England grant (£0.72m) to get project to the construction stage; with 4.5 to 6 MVA of new demand expected for housing and community facilities.	+6MVA at Hattersley primary	N/A
Stockport Town Centre Redevelopment	Mayoral sponsored regeneration of Stockport College campus, transport interchange and housing development; involving 2,000 new flats and 250k sq ft commercial development requiring 13MVA new demand. Development included in the UK government shovel ready/getting building fund.	+10MVA at Portwood primary	+3MVA
Northern Gateway / South Heywood	Northern Gateway land between jctns 18 and 19 of the M62. Around 12m sq ft of predominantly warehousing is proposed, along with 1,600 new homes. As the plot straddles two districts, Bury and Rochdale each is expected to deliver 6m sq ft. The overall development has therefore been divided into two projects – the Northern Gateway and South Heywood with 20-25 MVA of demand from 2023. New 2.2km link road from jctn 19 of M62 and new rail connection from Heywood to Bury via Castleton alongside tram extension to Middleton. Sites are key parts of Rochdale GMSF and has planning approval. Onsite work has commenced on the link road (part of phase 1 to be completed in 2022) which opens the space for development.	+24MVA at Heywood primary	+1MVA
Wigan GM Spatial Framework release	A number of sites across Wigan area identified for redevelopment during their GM Spatial Framework planning (5x GMSF land allocation release) with 21,000 new homes and 200,000 sq ft of development for industrial, commercial and warehousing requiring 22MVA of new demand across ED2 and ED3. Ongoing planning with Wigan LA for delivery.	+14MVA allocated as follows on primaries: 41% Worsley Mesnes, 17% Little Hulton, 28% Atherton and 14% Golborne	+8MVA

4.4 Scenario compliance with RIIO-ED2 Guidance

Following RIIO-ED2 business plan guidance, the scenarios supporting load related investment need to:

- be Net Zero carbon compliant,
- be guided by 2020 FES and CCC forecasts for GB including EVs, heat pumps, peak domestic demand and energy consumption,
- be based on transparent flexible modelling methodology, and
- deliver a well justified regional forecast per license area.

Step #1: building blocks moderated to produce bottom up regional DFES

Step #2: exclude scenarios not following RIIO-ED2 BPG
(eg, not meeting net zero or not aligned with EV related policies)

Step #3: check alignment of LCT uptakes against RIIO-ED2 BPG
(compare DFES with FES/CCC, **if** uptakes outside FES/CCC **then** adjust or justify differences)

Step #4: peak demand forecasts
(show effects of factors reducing peak demand and provide evidence for local demand growth)

Step #5: check alignment of total energy demand with RIIO-ED2 BPG
(compare DFES with FES/CCC, **if** uptakes outside FES/CCC **then** adjust or justify differences in demand growth)

Fig. 17. The five steps of the ED2 scenario alignment process following RIIO-ED2 business plan guidance

To meet these requirements, the five-step process flow shown in Fig. 17 was followed. This process demonstrates how our regional forecasts compare and confirms alignment with the national forecasts as required in the RIIO-ED2 business plan guidance. In summary, we put the range of forecasts used to inform our business plan side by side with the corresponding FES and CCC values disaggregated from national totals.

4.4.1 Step 1 of RIIO-ED2 alignment process: bottom-up DFES

Alignment of summated bottom up forecasts is checked against the corresponding proportion of national forecasts because top-down disaggregation is not appropriate. Our DFES provides better regional representation following bottom-up ATLAS methodologies informed by the DNO cycle of engagement with stakeholders (ie, stakeholder decisions informed by DFES and DNO planning by stakeholder plans).

ATLAS forecasts are used as the “single version of the truth” within all our processes. A full range of forecasting outputs are used to produce sub-sets of forecasting outputs for DFES on an annual business as usual cycle. To support the alignment process of RIIO-ED2 scenarios with guidance, this full range of forecasting outputs has been used to produce:

- LCT volumes that can be compared with FES and CCC forecasts;
- peak demand forecasts not only for the overall demand, but for individual demand components, ie domestic, industrial & commercial (I&C), EV charging and heat pumps to provide insights on how the individual components contribute to peak demand;

- total demand forecasts, ie forecasts of overall electricity consumption of domestic and non-domestic customers.

4.4.2 Step 2 of RIIO-ED2 alignment process: exclude scenarios with non compliant assumptions

The first step was to check the fundamental assumptions applied in our DFES to identify any misalignment with the requirements of the RIIO-ED2 business plan guidance. Applying these checks to our DFES has identified that it is appropriate to make exclusions, specifically:

- SP scenario is excluded as it is not meeting Net Zero carbon by 2050; and,
- ST scenario is excluded as it is not aligned with EV related policies, specifically the ban on sales of new vehicles is assumed to be beyond 2030 for ICEs and 2035 for plug in hybrids.

4.4.3 Step 3 of RIIO-ED2 alignment process: check alignment of LCT uptakes

Moving to the next step of the RIIO-ED2 alignment process, the LCT volumes for the RIIO-ED2 guidance compliant scenarios from our DFES (CO, CT and LW) were compared to the corresponding values from the FES and CCC for the RIIO-ED2 period and up to 2030. Our DFES forecasts are put side by side with the comparative FES and CCC values for the year 2030 because it is necessary for RIIO-ED2 investments to factor in the time that they take to implement and because 2030 allows us to look beyond the RIIO-ED2 price control period.

The 2030 ranges in the ESO's FES and CCC scenarios show national values and they have been allocated to our region following the ENA Common Scenario 2019[7] approach. More specifically, the national values for EVs, heat pumps and demand are allocated top-down to each DNO region using a weighting factor based on the customer counts per license area. ENWL has been taken to correspond to 8% of national totals. However, this is just one of many potential disaggregation approaches, such as division based on current numbers of vehicle registrations or peak demand, again highlighting why an exact match cannot be expected between our bottom up forecasts and those disaggregated from national totals.

As shown in Fig. 18, the EV volumes and energy demand range in our DFES is found to be in the middle of the combined range of the FES and CCC scenarios. It should be noted that several factors differentiate each forecast meaning that precise alignment could never be expected, specifically:

- ESO FES volumes consider only cars, whereas our DFES includes both cars and vans, with vans accounting for over 11% of EV energy demand in our DFES; and,
- CCC forecasts do not include EV energy demand and therefore has been estimated using the average per EV demand from the ESO FES multiplied by the CCC EV volumes.

[7] Energy Networks Association, *Common RIIO2 Scenario*, March 2019 (revised September 2019)

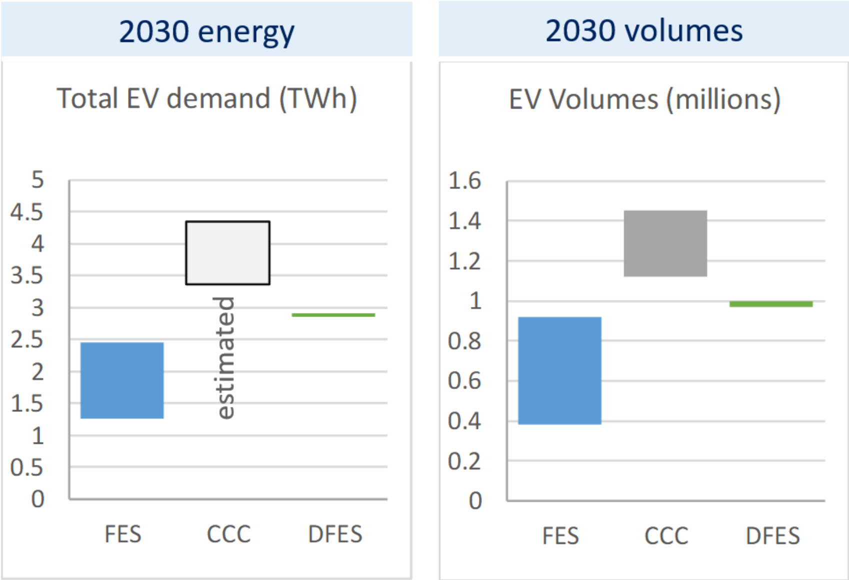


Fig. 18. Comparison of regional EV volumes and charging demand between the ENWL DFES compliant scenarios (CO, CT and LW) and the 2020 FES and CCC scenarios

The comparative analysis has revealed that all three ENWL DFES scenarios are ED2 compliant in terms of EV volumes and energy demand. The highest certainty can be evidenced for Central Outlook and CT scenarios that consider the expected national EV policies. More specifically, both scenarios share the same uptake trend that assumes a ban on sales of new ICE vehicles by 2030 and plug in hybrids by 2035. The LW scenarios considers policies that exceed the CCC's forecast's most ambitious recommendations and new plug in hybrid sales are banned from 2030.

As shown in Fig. 19, the heat pump volumes and energy demand ranges in our DFES are found to be lower than the corresponding ranges of the FES and CCC forecasts. It should be noted that:

- the ESO FES shows a wide range of HP uptake volumes that results in a wide range in energy demand;
- the CCC range of HP energy demand was not provided in their forecasts and therefore has been estimated using the average per HP demand from the ESO FES multiplied by the CCC forecast HP volumes.

The comparative analysis has revealed that the three DFES scenarios are lower than the FES and CCC ranges in terms of HP volumes and energy demand. Despite corresponding to lower demand and impact on our network, the volumes of heat pumps forecast in our DFES have been used in our ED2 planning. This is because the DFES values are considered to be a more accurate representation of the regional HP trends and their use instead of the national average values from FES and CCC for the following reasons:

- our region has higher levels of gas fuelled heating and higher levels of access to gas networks than the national average,
- our region has the highest level of regional poverty across GB and regional consumer choice shows that customers' decisions are likely to be driven by national policies and timescales, but the North West region will lag,
- our region has lower than average levels of building thermal efficiency,
- the DFES forecast on heating energy demand that informs the HP demand is based on modelling the actual local building stock which is less thermally efficient than the national average. This justifies the overlap of DFES HP demand with the lower part of the FES range;
- although our region has clear decarbonisation targets, there are no regional policies yet and we consider that they are less able to influence uptake of HPs compared to, for example, the adoption of EVs which could be stimulated by clean air zones in our regional city centres.

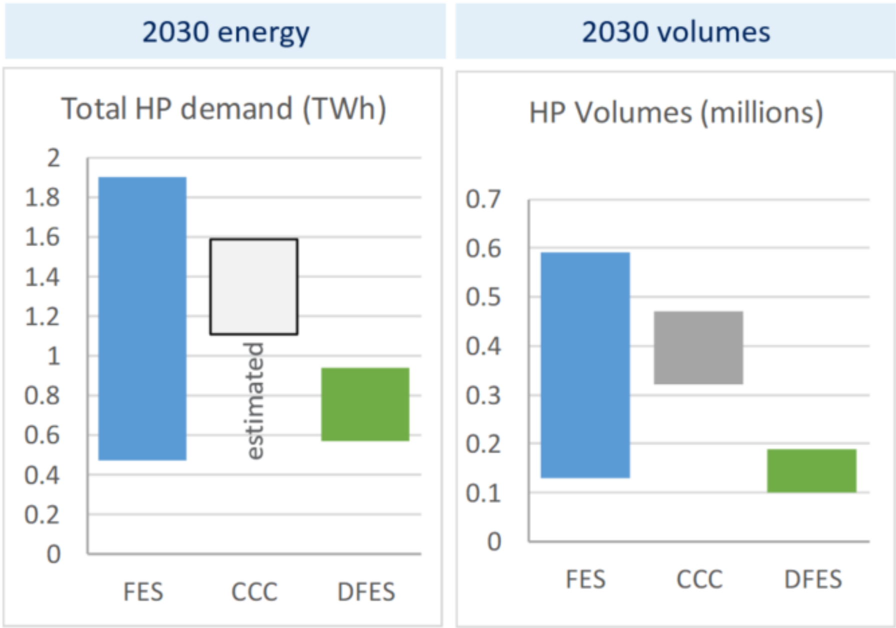


Fig. 19. Comparison of regional heat pump volumes and their demand between the ENWL DFES compliant scenarios (CO, CT and LW) and the 2020 FES and CCC scenarios

Given the high uncertainties on the level of the electrification of heating in the UK's transition to Net Zero carbon and the lack of strong evidence at the local level to accelerate electrification of the heating sector, the central/medium HP uptake trend adopted in Central Outlook scenario is considered as an average/central risk scenario.

4.4.4 Step 4 of RIIO-ED2 alignment process: peak demand forecasts

Steps 1 to 3 have demonstrated that CO, CT and LW scenarios from our DFES are compliant with the RIIO-ED2 guidance and that the slight misalignment in heat pump uptakes is well justified with our lower forecasts providing a more accurate representation of the expected local trends. In step 4 the justified LCT uptakes of the RIIO-ED2 compliant scenarios are considered in the modelling of peak demand based on comparison of our DFES with the ESO FES forecasts of domestic demand. Finally, more insights are provided on our DFES forecasts to demonstrate how a combination of factors result in reduced effects separately on peak domestic and peak I&C demand.

Fig. 20 shows the comparison of 2030 peak domestic demand forecasts from our DFES and the ESO FES. The lower levels of peak domestic demand shown in the FES are due to higher diversification modelled as a sensible approach for the transmission level, but not at the distribution level where demand is by nature is less / non- diversified. The FES 2030 forecasts are 15 to 35% less than the measured 2020 peak demand, but the ESO do not fully explain how this will be achieved.

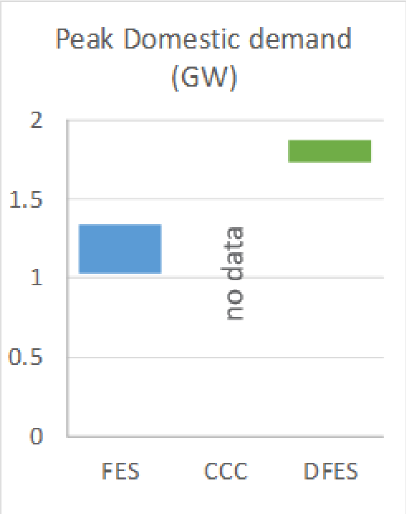


Fig. 20. Comparison of 2030 peak domestic demand for ENWL license area

To further explain how domestic demand is expected to affect future peak demand modelled in our DFES, Fig. 21 shows how peak domestic demand changes from 2020 to 2030. The comparison is shown for the same half-hourly period as Fig. 20, which is indicative of across the network winter peak demand. Depending on the scenario assumptions, the contribution of domestic demand to 2030 peak demand in MW is between 1.3% and 9% less than the 2020 level. It should be noted that our DFES approach includes the net position including future growth in the number of households and reduction in electricity requirements from improvements in appliance, heating and other efficiencies.

The forecast reduction in domestic demand between 2020 and 2030 is mainly driven by appliance efficiency and ToU tariffs effects on shifting demand away from peak load times. Central Outlook considers medium effects from efficiencies compared to the more ambitious high effects modelled in CT and LW scenarios. This is in line with the realistic expectations for our license area in which poverty levels are the lowest across the country and lower than the national average.

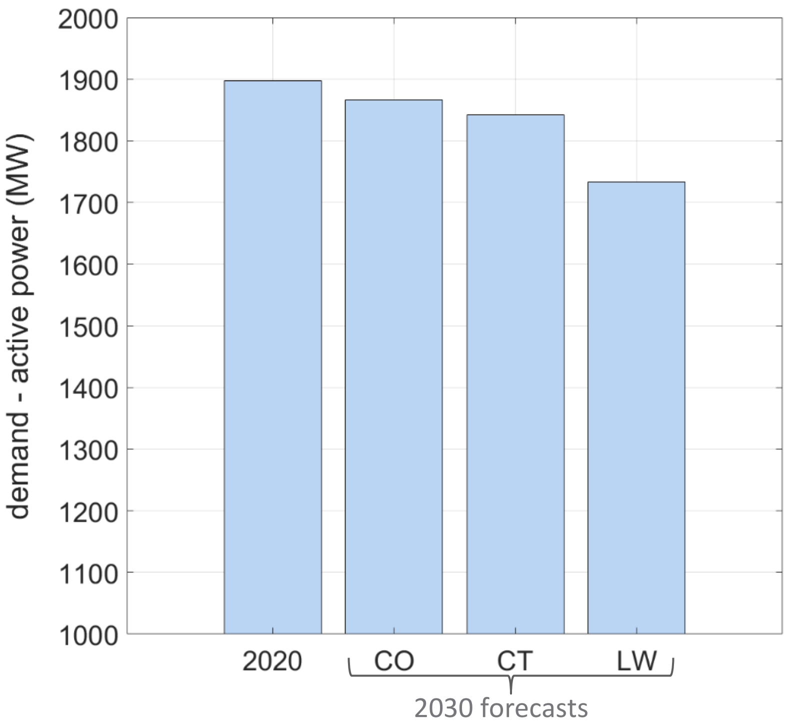


Fig. 21. The 2020 vs 2030 peak domestic demand in ENWL DFES

For industrial and commercial (I&C) demand there is no comparable FES and CCC forecast data. However, to provide a more complete justification on the methodology followed to forecast peak demand, Fig. 22 shows how peak I&C demand changes from 2020 to 2030. Again the comparison is shown for the same half-hourly period as that of Fig. 20 and Fig. 21, which is indicative of winter peak demand of across the network.

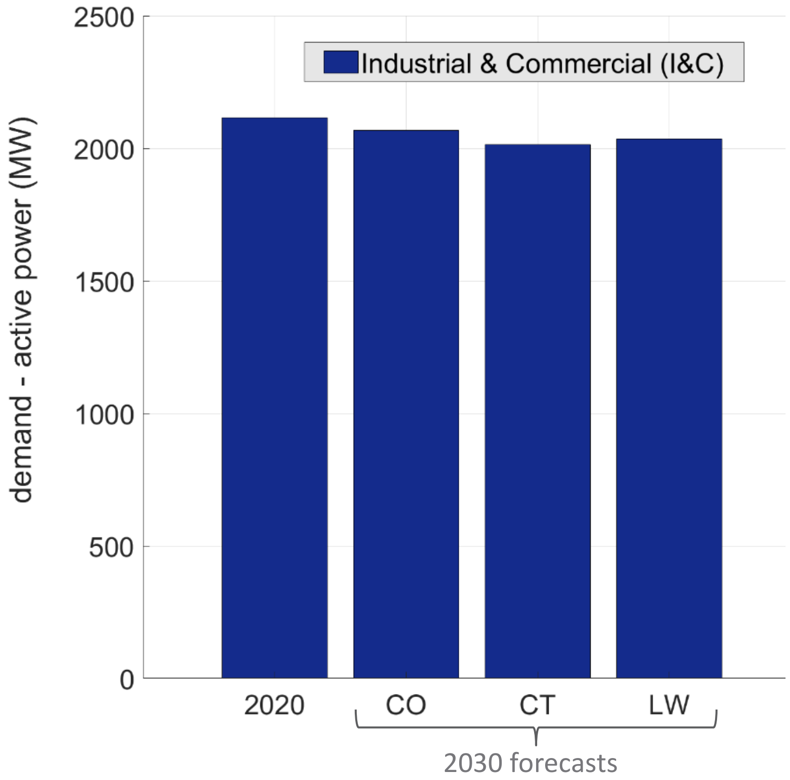


Fig. 22. The 2020 vs 2030 peak I&C demand in ENWL DFES

Depending on the scenario, the peak I&C demand in MW varies between 2.2% and 5% less than the 2020 level. It should be noted that the DFES forecast for I&C demand reflects economic growth and efficiency improvements. Similar, to domestic demand, ToU tariffs and efficiencies are the key factors driving down overall peak I&C demand. However, this reduction in I&C peak demand is offset by the I&C growth driven by the local economic forecasts and business growth particularly in enterprise zones.

Combining all demand components (domestic, I&C, LCT effects etc), the corresponding comparison between the actual 2020 value and our 2030 peak demand forecasts is shown in Fig. 23. Planned developments and EV charging are the primary factors driving up peak demand, whilst efficiencies and smart EV charging are reducing demand at the same time.

To avoid any misinterpretations, it should be repeated that our DFES uses true peak demand forecasts produced by our ATLAS half hourly modelling to define peak demand occurring at different times across individual assets. The summation of asset peaks differs from the aggregated peak demand forecast at higher up our network. The ATLAS approach followed in our DFES is tailored to distribution network planning, focusing on the fact that distribution networks need to secure local supply and are less able to utilise undiversified or less diversified generation.

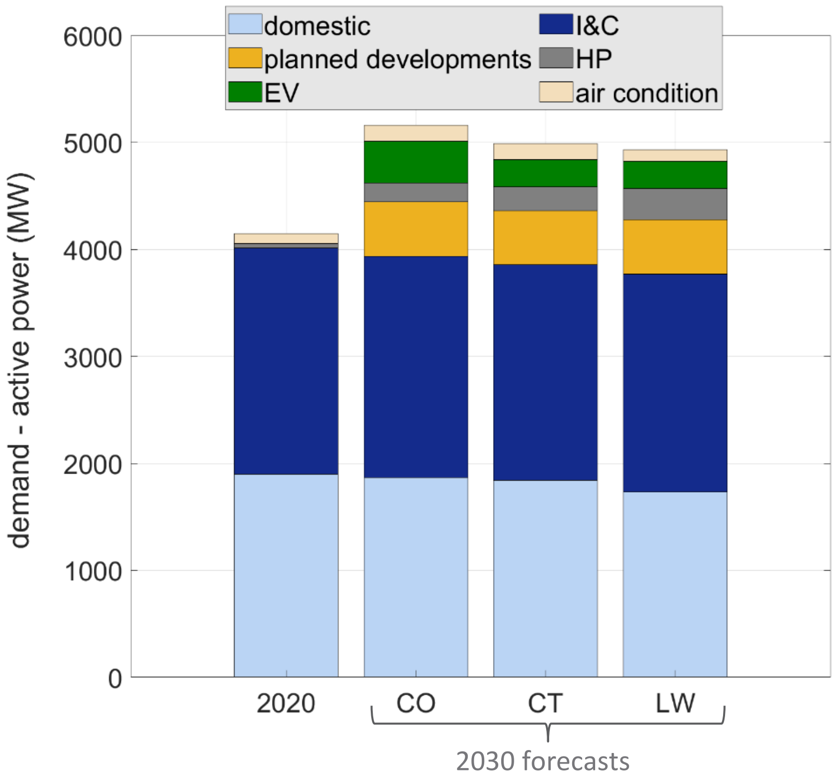


Fig. 23. **Decomposition of 2020 and 2030 peak true demand**

4.4.5 Step 5 of RIIO-ED2 alignment process: check alignment of total energy demand

The final step of the process for checking alignment of our DFES forecasts and RIIO-ED2 guidance is to compare the forecasts of overall energy / electricity demand with the reference CCC and FES forecasts and justify potential differences. Fig. 24 shows this comparison of ENWL DFES range with the corresponding from FES and CCC for both historical values in 2020 and 2030 forecasts. The illustrated DFES range corresponds to the overall net energy requirements of our region including losses to allow comparison with the FES values which we assume will correspond to the total energy required to be supplied from the transmission system.

Both FES and CCC show demand growth within this period, even with FES's use of very high efficiency assumptions. Compared to our DFES, both FES and CCC are top-down allocated ranges driven by customer counts and do not reflect local industrial and commercial demand. On the contrary, the DFES considers a) historical figures calculated on per substation measurements plus the energy supplied by embedded generators and b) forecasted electricity consumption built on well justified bottom-up forecasts of EVs, HPs domestic and I&C demand. Additionally, unlike FES and CCC, the DFES captures information from our cycle of engagement with local stakeholders such as enterprise zones, accepted connections and local plans with strong LA and UK government backing and funding.

Overall, the DFES range is a well justified and well informed regional forecast of the electricity consumption range by 2030 for all these reasons. Even though FES and CCC figures neither captures local I&C demand, nor planned developments, the comparison of DFES with CCC forecasts shows that our DFES electricity consumption forecasts are within the national average CCC figures that do not consider the very high efficiency assumptions modelled in FES.

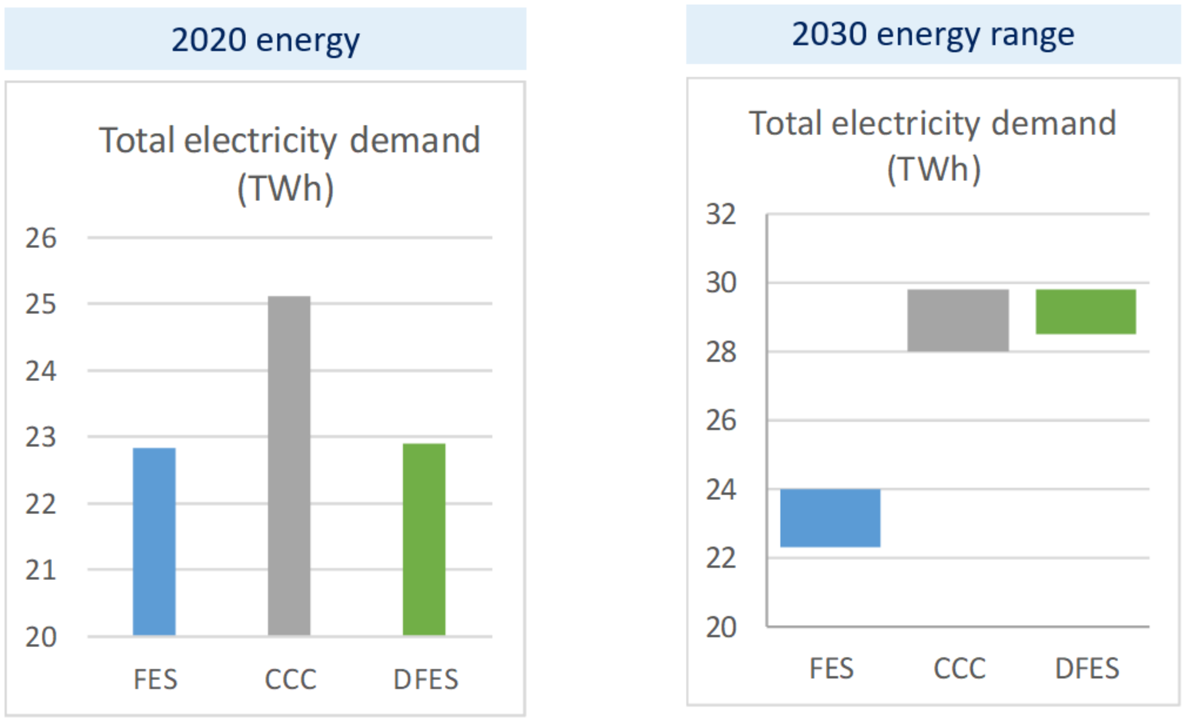


Fig. 24. **Comparison of 2030 electricity consumption for ENWL license area**

4.5 Optimal investment plan using highest certainty scenario

To produce an optimal RIIO-ED2 load related investment plan, our high-level approach can be summarised as follows:

- the baseline (ex-ante) allowance is informed by the highest certainty scenario that is compliant with RIIO-ED2 guidance,
- the range of post RIIO-ED2 uncertainties is used to examine whether investment above the identified level based on the highest certainty scenario is required to not foreclose network futureproofing to facilitate Net Zero carbon by 2050. This is achieved by both a high-level comparison of investment needs between the highest certainty scenario and the other lower certainty scenarios (see section 4.6 on sensitivity analysis), as well as by using cost benefit analysis that considers multiple factors and different options including flexibility (see section 6.2),
- intervention costs and risks are minimised at the optioneering stage through a) network optimisation that considers strategic planning and b) the use of flexibility). This approach to identify optimal interventions is carried out independently for every forecasting scenario included in our RIIO-ED2 analysis, and
- the lower certainty scenarios are used to quantify the min-to-max range of investment under uncertainty that could be funded by uncertainty mechanisms.

Our RIIO-ED2 baseline load related investment plan is based on our Central Outlook scenario in which out of all our scenarios we have greatest certainty. This scenario has been produced based on the ATLAS methodology and therefore:

- it uses central/average assumptions for the majority of areas (e.g., heat pumps, efficiencies, smart EV charging etc), and,
- it uses specific assumptions for areas with more certainties, e.g. low and medium EV uptakes were not driven by national policies for a 2030 ban on sales of new ICE vehicles and therefore the high EV uptake was adopted.

As described in more detail in the stakeholder engagement section 4.3 of this document, the factors that result in higher certainty for our Central Outlook scenario include:

- its consideration of national policies driving the electrification of transport and heating, given that strong evidence could not yet be identified for LA policies accelerating decarbonisation to meet local Net Zero carbon targets before 2040;
- the ATLAS modelling approach where confidence factors for the connections pipeline are based on identified historical performance; and
- the Central Outlook, like all our DFES scenarios, models only projects with secure funding and LA and UK government backing, through the application of certainty ranking in line with ES Catapult and Scottish Government guidance for LAEPs to identify well justified regional developments.

The sensitivity analysis described in the following subsection reveals that the load related investment associated with our Central Outlook scenario does not foreclose the futureproofing of our network to facilitate an early decarbonisation of transport and heating. Therefore, the suitability of Central Outlook is verified as the scenario to quantify our RIIO-ED2 baseline allowance.

4.6 Sensitivity analysis to inform investment range under uncertainty

As the highest certainty scenario, Central Outlook plays an important role in informing the optimal investment plan and the associated RIIO-ED2 baseline (ex-ante) allowance. However, all other lower certainty scenarios, in particular those which do not follow the RIIO-ED2 guidance, are used to inform the min-to-max investment range that could be required and funded by uncertainty mechanisms.

To quantify the sensitivity of load related investment needs to different scenarios that have a slower or faster pace of the electrification of transport and heating, we have expanded the analysis beyond the CO, CT and LW scenarios that comply with RIIO-ED2 guidance to include the following scenarios:

- System Transformation (ST) scenario from our DFES 2020. It is very similar to our Central Outlook scenario with the main difference being that it considers lower EV uptakes because it does not reflect the 2030 ban on sales of ICE vehicles;
- Steady Progression (SP) scenario from our DFES 2020. It does not meet the 2050 Net Zero carbon target and in addition to having lower LCT uptakes from the other DFES scenarios, its confidence factors for the connections pipeline are less than those identified from the analysis of historical performance;
- accelerated decarbonisation versions of CO, CT and LW scenarios where the main difference from the original DFES 2020 scenarios is that transport and heating is fully electrified before 2040 for a large part of our license area.

The accelerated decarbonisation versions of CO, CT and LW scenarios consider the same LCT uptake trends for EVs and heat pumps as shown in Fig. 25. All other scenario assumptions are the same as per the original DFES scenarios, resulting in the peak demand forecast for the whole of our region (aggregated demand of individual peak demand of all GSPs) between 5.9GW and 6.2GW.

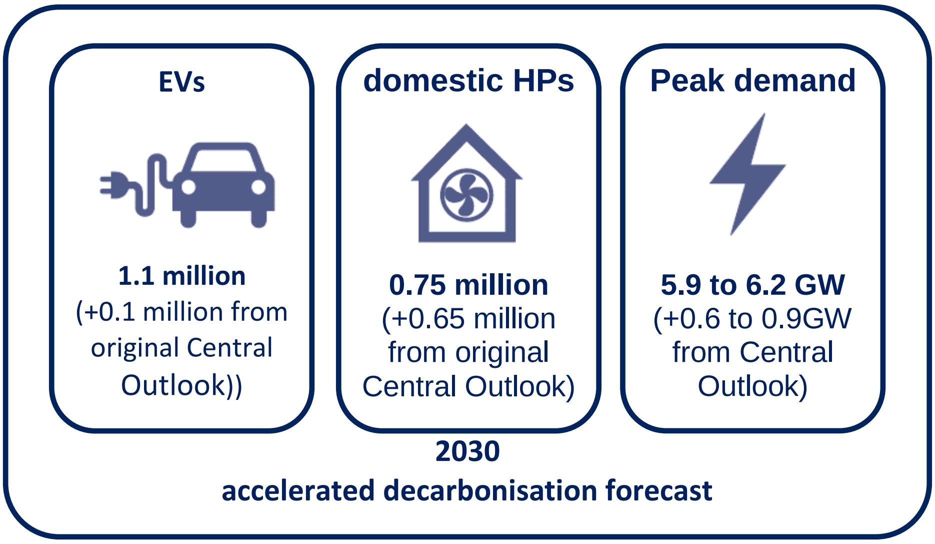


Fig. 25. LCT volumes and peak demand range for the accelerated decarbonisation versions of DFES CO, CT and LW scenarios for year 2030

Fig. 26 shows the trends of future peak demand for all scenarios used to inform our RIIO-ED2 submission. The dashed lines correspond to all scenarios that do not comply with RIIO-ED2 guidance, but instead inform the min-to-max load related investment during and after the RIIO-ED2 period. The accelerated decarbonisation scenarios (CO acc, CT acc, LW acc) inform the maximum of the peak demand range and the top of the investment range. They effectively bring forward the significant demand growth of CT and LW scenarios given that local decarbonisation policies accelerate the electrification of transport and heating.

The bottom of the peak demand range is informed by the SP scenario that does not meet the 2050 Net Zero carbon and importantly EV uptake is not driven by the 2030 ban on sales of new ICE vehicles. In the same scenario it is assumed that major developments with secured funding and strong UK government and LA backing do not materialise the expected demand growth and projects in the connections pipeline underperform (50% lower demand growth) compared to historical performance.

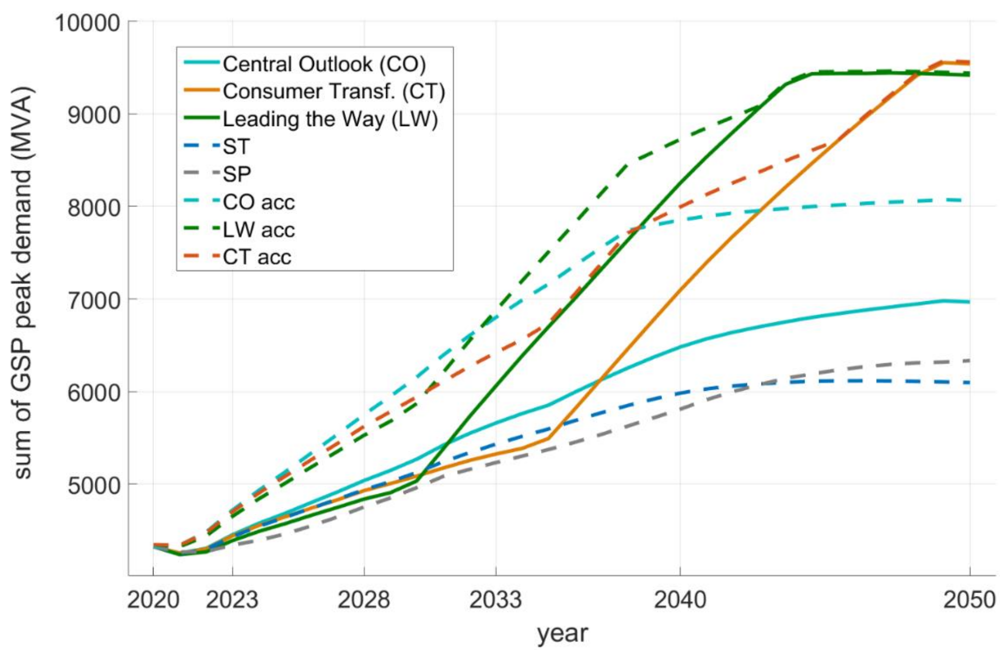


Fig. 26. Peak demand forecasts for all scenarios informing our RIIO-ED2 load related investment programme. Dashed lines correspond to scenarios not following RIIO-ED2 guidance

Our analysis to inform our RIIO-ED2 load related investment has been based on DFES 2020. Our DFES 2021 will be published shortly after our final RIIO-ED2 submission and draft results indicate that by 2030:

- the EV uptake range can exceed the range of RIIO-ED2 scenarios, ie up to +18% from the accelerated decarbonisation scenarios; and,
- the heat pump uptake range is well within the range of RIIO-ED2 scenarios, ie top of the range does not exceed one third of the accelerated scenario trends.

The top range of our accelerated region scenario forecasts of LCT volumes for 2030 are around 14% higher than the top range from our draft DFES 2021 workings. At a high level, this means that we expect that our detailed forecasting, impact analysis, optioneering and cost assessment for RIIO-ED2 accelerated decarbonisation scenarios will cover the investment range that would be produced using our draft 2021 DFES scenarios.

The difference in this year's EV uptake forecasts is mainly due to the significant reduction of battery costs observed during the last financial year. This reduction has been higher than that forecasted a year ago, thus resulting in consumer choice modelling results suggesting that more customers are likely to adopt an EV based on their reduced cost rather than mainly deciding based on national policies to ban ICE vehicles. However, an additional key factor that affects consumer choice is access to EV chargers with latest sensitivity analysis results on consumer choice suggesting that customer decision is highly dependent on availability of EV charging infrastructure.

Overall, we believe that:

- our RIIO-ED2 accelerated decarbonisation scenarios can capture the top of the investment range as they consider more LCTs than the top of the draft 2021 DFES range; and,
- our proposed ex-ante allowance should not be updated as the allowance based on DFES 2020 "best view" (Central Outlook scenario) does not foreclose transition to Net Zero whilst delivering at lowest cost to customers.

5 NETWORK IMPACT ASSESSMENTS

5.1 Overview of network impact assessments

Whilst accommodating the efficient and economic connection of additional LCTs to reach Net Zero, our network must continue to be safe and provide reliable supplies for our customers. Network impact assessments check the future compliance with legal requirements and technical standards including those shown in Fig. 27. A wide range of network planning and operation aspects are covered to ensure that equipment is used within its capability, the supply to customers remain within limits and are secured through minimum design standards.

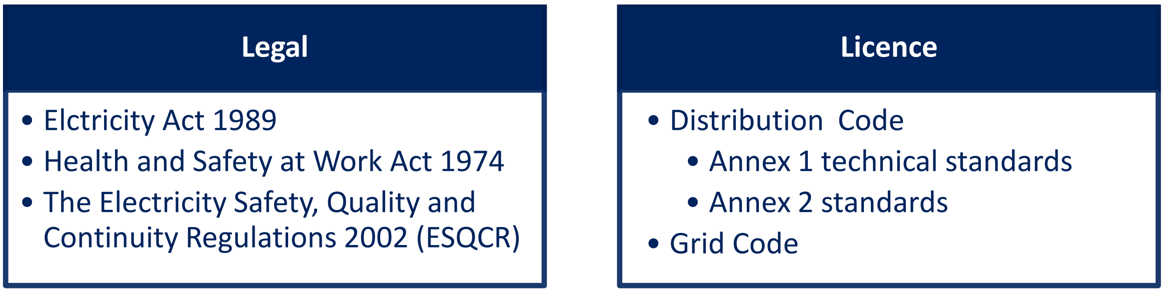


Fig. 27. Network compliance requirements

Our forecasts of electricity demand and distributed generation are used as inputs in network impact assessments. These assessments allow us to understand if future requirements for power at different parts of the network can be supplied by the existing network capacity or if interventions are required to accommodate the demand and generation growth. Fig. 28 shows the components of our network impact assessments that are described in this section and are based on Ofgem's framework for the reporting of the methodology underpinning RIIO-ED2 load related investment programmes.

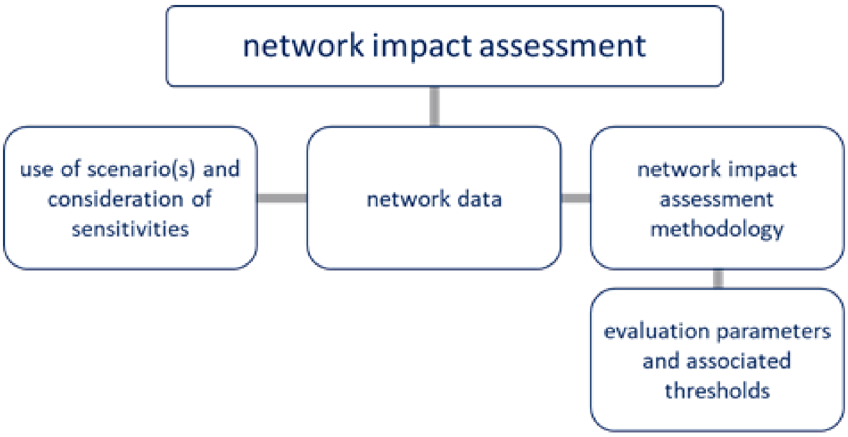


Fig. 28. The components for network impact assessment from Ofgem's reporting framework for the RIIO-ED2 methodology of the load related investment programme

5.1.1 Introduction to network impact assessments

Network impact assessments are carried out for both the EHV and HV and LV networks to determine the RIIO-ED2 LRE investment plan. Different approaches are applied at different voltage levels due to the differing size, demand diversity, volume drivers and complexity per voltage level.

Our approach to assess EHV network impacts for a given scenario is based on forecasts per substation and detailed power system modelling (i.e. using IPSA power system analysis software). This analysis allows us to locate where network parameters exceed thermal, voltage and fault level limits, whilst also allowing us to analyse and compare the effectiveness of alternative solutions.

Our approach to assess HV and LV network impacts for a given scenario is based on the use of our bespoke Future Capacity Headroom (FCH) tool to quantify thermal, voltage, fault level and harmonic distortion issues.

5.1.2 Network data for impact assessments

A number of key data sources are used in the network analysis that underpins our RIIO-ED2 LRE plan. Our Master Asset Management System (MAMS) database contains a corporate auditable record of our transformer and switchgear ratings, of which our system study models are built upon. Cable records are contained in our GIS system and again the master modelled data is verified against this source. Network parameters published in our Long-Term Development Statement and detailed demand and generation data from our detailed DFES forecasts are also key sources of information for our detailed study work.

For the modelling of our EHV network in impact assessments, the detailed electrical parameters of all EHV assets, ie impedance and susceptance values for transformers, lines and cables, as well as operational aspects, e.g. on-load tap changer settings and voltage targets, are modelled in IPSA power systems analysis tool. Our IPSA network model exceeds 3,000 nodes and covers the whole 132kV and 33kV network and incorporates an equivalent reduced network representation of the transmission network, including detailed information on transformers and circuit ratings.

HV and LV network impact assessments are undertaken using our tailored FCH tool which models the actual connectivity of the whole HV and LV network (over 300,000 nodes including over 35,000 secondary substations) and allocates half-hourly loading to the whole of the network using a combination of regional forecasts (per LA) derived from measurements from all HV feeders (over 3,000 feeders) in our license area.

5.1.3 Forecasts in network impact assessments

Our EHV network impact assessments of future loading on our network are undertaken using local peak demand forecasts, as well as those for storage capacity and DG per generation type for each EHV substation (around 450 substations). The analysis is carried out for each of our RIIO-ED2 scenarios, ie all DFES scenarios and their accelerated decarbonisation versions. How forecasts are applied in network assessments is described in the following sections. Individual substation peak demand forecasts are applied either in isolation from adjacent substations to identify local constraints; or, together with adjacent BSPs and primary substation demand growth, especially for extraordinary regional EHV developments.

For the HV and LV network impact assessments, forecasts per LA are used as inputs to our FCH tool to identify locations and volumes of thermal and voltages issues in each region. These forecasts comprise volumes of LCTs (EV, heat pumps and rooftop PV), as well as domestic and non-domestic demand trends per LA. Future peak demand across the whole HV and LV network is estimated by adding half-hourly measurements at the head of HV feeders that are typically the last point of monitoring to aggregated LCT consumption profiles determined by combining LCT volume forecasts multiplied by LCT half-hourly profiles (ie, diversified for HV and non-diversified for LV).

For the assessments of harmonic distortion issues, LCT forecasts of the number of EVs per secondary substation (ie, around 35,000 substations) are used as inputs to an empirical rule based on a detailed WPD trial study. More details on our assessments are provided in the following subsections.

5.2 EHV network impact assessments

5.2.1 Thermal and voltage issues

Thermal assessments of our EHV network loading are undertaken in two stages; an initial approximate assessment is followed by more detailed studies where required. The forecasted peak demand at the end of RIIO-ED2 period, ie FY2027/28, is compared to the existing firm capacity of each EHV substation, ie all BSPs and primary substations. This comparison is carried out for all our DFES scenarios and their accelerated decarbonisation versions. Should the anticipated demand growth approach a substation's firm capacity, then detailed studies are undertaken to explore the issue further. We use our IPSA models to study the 132 to 33kV networks down to primary substation HV busbar level.

Load growth figures in MW and MVAr (based on forecasted MVA and assessed power factors at times of peak load) are entered into the model to enable detailed load flow simulations for different years and scenarios. The transmission system is assumed to remain constant. Studies using these models are undertaken to identify network overloads and non-compliant voltages. Solutions to these network overloads are then determined through detailed analysis, with a range of alternative investment options being explored.

5.2.2 Short circuit studies

EHV and primary substation HV fault levels are simulated using our network models. In addition to our IPSA model of today's network, we maintain an "All Generation" IPSA model which includes representation of all accepted generation connections greater than 1MW. The model also incorporates a reduced representation of the transmission network set up for the maximum fault level operating condition.

This model was updated with the FY 2027/28 forecasts of peak demand and the corresponding increased G74 motor fault in-feed contributions that are required for fault level calculations. In addition to this, forecast generation was also included, with an estimation of additional synchronous and non-synchronous inverter-based fault level contributions factored into the model at primary level. The study steps we have undertaken are as follows:

- for primary substations (fault levels at 11 and 6.6kV busbars):
    - calculations were undertaken using the latest IPSA All_Gen model at the time (October 2020), which not only includes existing generation, but also includes all accepted generation connections >1MW which have not yet connected;
    - the G74 contribution at each primary in the All_Gen model was then modified based on the Central Outlook forecast for FY 2027/28;
    - forecast DG per primary is broken down by technology type which allowed overall figures for inverter connected and non-inverter connected generation to be derived for each primary;
    - for inverter connected generation a fault contribution of 1 x full nominal current was assumed. For 'make' fault level a factor of 2√2 was also applied;
    - for non-inverter connected generation a fault contribution of 4 x nominal current was assumed. For 'make' fault level a factor of 2√2 was also applied;
    - fault levels were calculated using the ISPA All_Gen model with the increased G74 contribution, and then the 11 and 6.6kV fault levels for each primary were increased individually to include the contribution of non-inverter and inverter connected generators as per the above;
    - it should be noted that our "All Generation" IPSA model already includes accepted HV generation schemes. To therefore prevent double counting when adding models of the forecast generation, we reduced the amount of extra generation added to the IPSA model for the small number of sites which had a large increase in the DG

forecast due to accepted schemes. The amount of additional generation included in the DFES forecast at these selected sites was replaced with typical capacities based on the capacities at other primaries, specifically 0.125 MVA for non-inverter connected generators and 0.5MVA for inverter connected generators;
    - the calculated HV fault levels were compared to the existing switchgear 'make' and 'break' ratings, with the sites where the estimated future fault level exceeded 97.5% of the corresponding rating identified for intervention.
- for BSPs (fault levels at 33kV busbars):
    - for the 33kV fault levels only the IPSA "All Generation" model was used, which includes all accepted generation schemes. The remaining DG uptakes from the forecasts that were not part of the connections pipeline were excluded from the 33kV fault level calculations;
    - the 33kV fault levels were compared to the existing switchgear 'make' and 'break' ratings. Sites where the fault level exceeded 97.5% of rating were identified for intervention.

It is noted that the DG uptakes in the forecasts that are not part of the connections pipeline were low with limited impact at 33kV. The main impact on 33kV fault levels comes from the large accepted generation schemes, which are already included in the model and impacts due to forecast 33kV generators are greatly dependent upon where in the network they connect. Investment to address fault level issues associated with new connections are accounted for in connections driven reinforcement budgets.

Our RIIO-ED2 LRE plan is based on interventions being required when fault levels exceed 97.5% of existing switchgear 'make' and 'break' ratings. This level has been selected instead of 95% because although our simulated short circuit levels are inaccurate, they are considered to be cautious due to our use of pessimistic assumptions for equipment parameters and operating conditions.

5.3 HV and LV network impact assessments

5.3.1 Thermal, voltage and fault level assessment

Unlike the EHV network where detailed electrical parameters for circuits, transformers, operational aspects etc are modelled in power flow simulations using the IPSA power system analysis software, a similar approach is not feasible for the larger HV and LV networks, so a simplified approach is required.

To justify that our bespoke FCH tool can use more accurate local modelling of demand growth and therefore reduce the amount of overloads and stranded assets in the planning results, we have carried out a comparative analysis with a tool developed by WSP as part of ENA's LCT modelling project. More specifically, the following two software tools have been tested and preliminary results compared to select the most appropriate for determining our RIIO-ED2 HV and LV load related expenditure plan:

- the LCT planner tool that has been developed by WSP through ENA's LCT modelling project that we have actively participated with all other DNOs; and,
- the Future Capacity Headroom (FCH) model that was developed by ENWL and used for our RIIO-ED1 submission

Both tools can:

- model the network from the HV feeders connected to the primary substations down to LV ways, and
- be used to calculate network impacts in terms of thermal stress (overloads) and violations of accepted voltage levels.

Our analysis has revealed that the FCH model is not only more representative of the current and future performance of our HV and LV networks compared to the LCT planner tool, but the use of the latter poses significant risks to significantly overestimate or underestimate the required interventions to accommodate demand growth in RIIO-ED2.

The key differences of both models that can reveal the associated advantages and disadvantages are summarised as follows:

- network representation:
    - FCH model: the model considers the actual connectivity of the whole HV and LV network (over 3,000 HV feeders and around 35,000 secondary substations). It also considers the actual volumes of domestic and non-domestic customers per HV and LV feeder.
    - LCT planner tool: the model does not consider the actual connectivity of the HV or LV network. it uses clusters to group HV and LV networks (18 and 17 respectively) to simplify modelling.
- modelling of start/base year loading:
    - FCH model: the model uses the historical half-hourly measurements from corporate systems (ie, FLA) for each and every HV feeder (over 3,000 feeders) and an allocation of loading across LV feeders using the volumes of customers and the actual connectivity of LV networks;
    - LCT planner tool: it does not consider any measurements for the loading of HV feeders. The model considers estimates for domestic, industrial and commercial customers based on volumes of customers. Unlike the FCH model, the use network clusters means that the LCT planner tool is unable to consider the actual volumes of customers.
- regionality in future loading:
    - FCH model: the model uses regional forecasts for each local authority within our region. Specifically, 35 regional trends are employed for each year for EV uptakes, heat pump uptakes, domestic demand growth and non-domestic demand growth.
    - LCT planner tool: the model can use only one global (ie, across the whole network) forecasting trends. Specifically, this covers one global trend for per year for EV uptakes, one for heat pump uptake trends and one for the volumes of domestic customers. Apart from the lack of regionality in forecasts, another critical disadvantage is that the LCT tool user cannot specify the non-domestic demand growth and the effects that can shape domestic demand levels (eg, from efficiencies) on domestic demand.
- generation modelling (more critical for impact assessment on LV voltage):
    - FCH modelling: modelling of domestic PV using regional trends and associated half hourly profiles.
    - LCT planner tool: no generation type modelled.

The above summary clearly demonstrates the comparative advantages of using the FCH tool to assess network impacts due to forecast load growth and LCT uptakes during RIIO-ED2 for the whole of our HV and LV network.

Apart from these clear advantages of using the FCH tool for the impact assessments in the HV and LV network, our analysis has also revealed that the LCT planner tool does not show a sensible sensitivity in terms of per year network interventions. Quantities of network interventions were not in proportion to the annual increases in EV and heat pump volumes. This is illustrated in Fig. 29, where the per year increments (“delta”) in the numbers of EVs and heat pumps (straight lines) are not correlated with the associated per year cost of interventions at HV feeders, LV substations and LV feeders (bar plots). The costs are non-discounted total installation costs using the cost optimisation in the LCT planner tool for all available traditional network intervention options. Typical signs of the non-sensible results can be seen on year 2028 where HV feeder costs are lower than the previous year when new EVs in 2028 are over 50% greater than the number of additional EVs in 2027. Similar non-sensible behaviour can be seen on year 2035 when tens of thousands of additional EVs are considered in the forecasts and there is minimal reinforcement across the HV and LV networks.

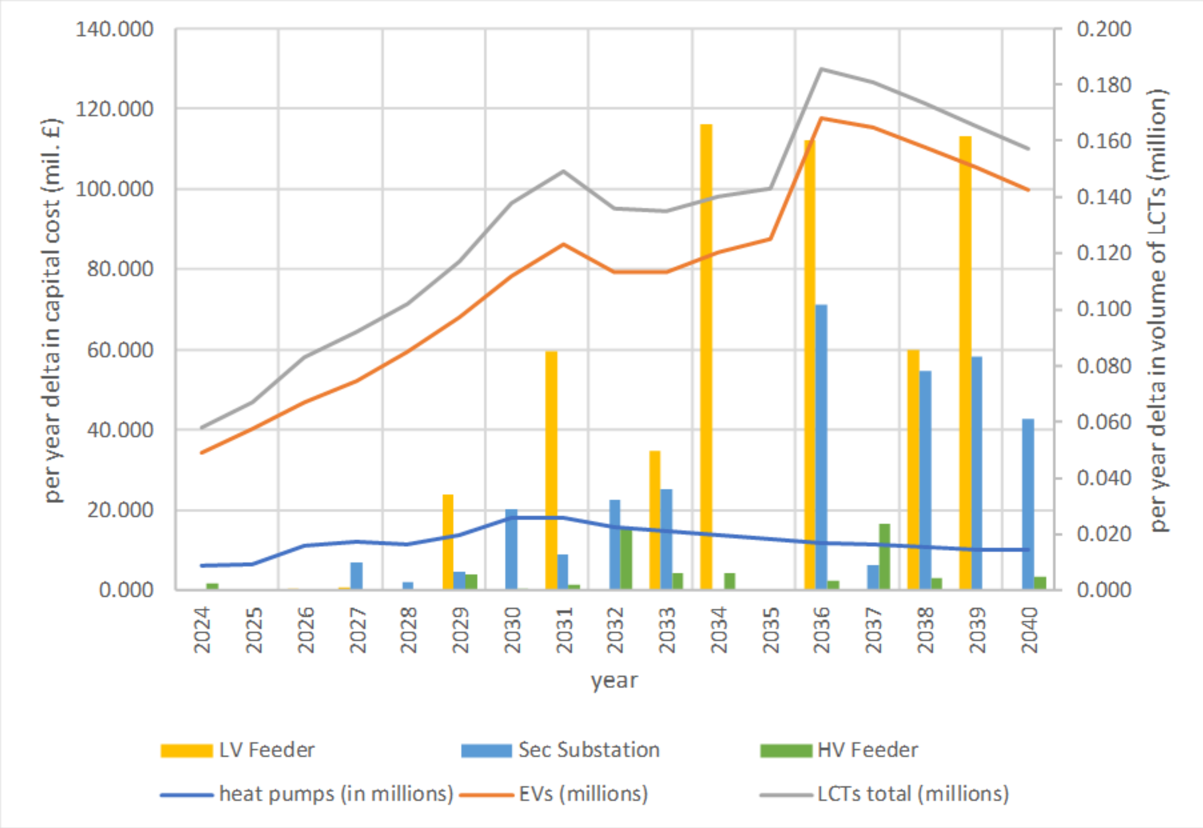


Fig. 29. Per year LCT uptakes and associated HV and LV intervention costs using WSP's LCT planner tool

The FCH model was chosen to identify thermal and voltage issues arising during the RIIO-ED2 period and the required intervention options in terms of volumes of the most cost efficient options across the HV and LV network.

Outputs from the FCH model are counts of assets in the HV and LV networks 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 site 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 issues are likely to occur at the LV network level.

Modular solutions and associated costs are employed 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
- voltage issues – LV feeders / secondary substations

5.3.2 Harmonic distortion assessment

The FCH model can also be used for identifying issues of harmonic distortion from the LCT uptakes in addition to quantifying requirements to deal with thermal and voltage issues. However, the FCH tool's simple harmonic assessment does not acknowledge the fact that harmonic issues are not directly proportionate to the volumes of LCTs[8] [9]

Recent work[10] carried out by RINA for Western Power Distribution (WPD) has used extensive analysis to show harmonic effects of residential EV charging not only at the connection points, but also at the head of LV feeders. This study undertook measurements and extensive simulations of 3 and 7kW domestic EV charging on urban and rural LV networks. Our focus has been on the harmonics aspect of this study's wider scope which included thermal stresses on LV networks.

WPD's project identified an empirical approach for correlating volumes of residential EV chargers fed by an LV feeder with the probability exceeding harmonic distortion limits. This correlation has been expressed using different diagrams for urban and rural networks.

Our analysis has adopted these correlation diagrams to quantify requirements for filters to deal with harmonic distortion issues associated with forecast LCT uptakes. The analysis has been carried out separately for urban and rural LV networks. Forecasts of EV volumes per year per secondary substation have been considered across the whole of our LV network. A 70% probability of violating the harmonic distortion threshold has been considered for the quantification of the filter requirements to tackle the harmonic distortion issues.

[8] "*An experimental approach for assessing the harmonic impact of fast charging electric vehicles on the distribution system*", JRC Science & Policy Reports, European Commission, 2015

[9] "*Impact of electric vehicle charging on unbalance and harmonic distortion – field study in an urban residential area*", CIRED paper 1404, Lyon, Jun 2015

[10] "*Electric Vehicle Charging: Monitoring & Analysis / project number PSE0564001*",rev. 21, WPD, Bristol, UK, May 2018

6 NETWORK SOLUTIONS

6.1 Network development planning

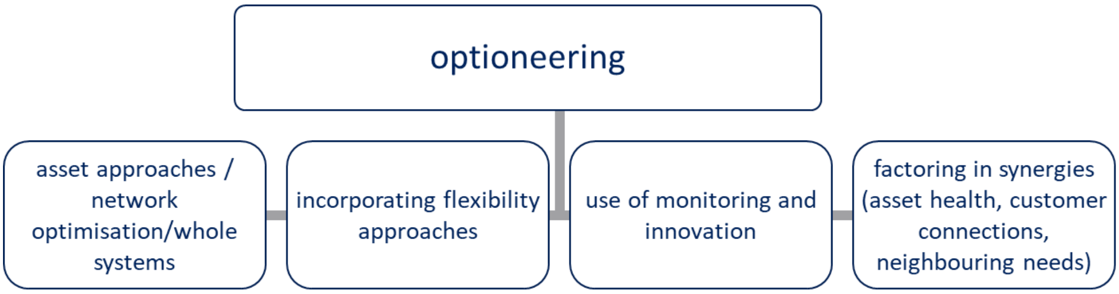


Fig. 30. Components considered in optioneering to ensure optimal network development planning

Comprehensive optioneering including the components shown in Fig. 30 is undertaken following the identification of network issues through our network impact assessments. Alternative approaches are thoroughly assessed to ensure that the optimal development plan is identified, considering the timing of interventions and not foreclosing future pathways. For development of the EHV network, this is supported by use of rigorous cost benefit analysis which ensures that flexibility and innovative solutions are considered equitably alongside traditional asset solutions. Further detail on our use of flexibility and our approach to innovation can be found in our DSO Transition Plan (Annex 2) and our Innovation Delivery Plan (Annex 24) respectively. We ensure that whole systems options are thoroughly considered by sourcing flexibility services from local stakeholders and working with the owners of the electrical networks we are interconnected with, as described in our Enabling Whole System Solutions (Annex 6).

6.2 Incorporating flexibility into our planning and investment plan

Flexibility will continue to be considered first as a solution for when actual network developments are implemented during the RIIO-ED2 period. We seek flexibility services for every network capacity requirement as described in the Flexibility First section of our DSO Transition Plan (Annex 2).

In developing our baseline (ex-ante) LRE plan, we have evaluated the potential sites where flexibility services could provide the required capacity to deliver cost savings through the deferral of asset solutions in the following three steps:

1) Establish the capacity needed in each part of our network in terms of the magnitude and duration of the requirements,
2) Estimate the availability of potential flexibility services in two ways; examination of existing customers and through a flexibility services Expression of Interest, and
3) Estimate the ceiling for flexibility service costs using a CBA of the costs of conventional asset based reinforcement for the same sites.

6.2.1 Forecasting flexibility service potential

To identify the sites where flexibility services can release the required network capacity, we have followed a different approach between primary (EHV) and secondary (HV and LV) networks. In EHV networks we have forecast the flexibility service potential based on the availability of Demand Side Response, DSR, providers and DG/battery storage.

The application of flexibility service for EHV capacity requirements has been assessed as follows:

I. First we forecasted the MW availability of flexibility service providers:
   - non-domestic customers with available half-hourly load readings were considered in our assessment of the potential DSR capacity. This has been calculated as the MW

distance between the customers' aggregated peak demand and their aggregated average demand. Our assumption here is optimistic for flexibility services, as we assume that all customers can shift demand at times of peak load and operate at their average demand instead, and

- generators capable of providing flexibility services, ie non-CHP gas fired generators and grid-scale battery storage was considered as able to provide their installed capacity for flexibility services.

II. For identified EHV network issues we then compared the flexibility service MW availability with the required capacity. In all cases where required capacity was lower than the flexibility service availability, we also considered if there is potential for new generation and battery connections as identified through our Expression of Interest described in section 6.2.2 of this Annex. For areas with high potential for such new connections we have assumed that DG and battery storage will be in position to provide flexibility and therefore meet the required MW capacity.

III. Our final assessment considers for all sites the time requirements, i.e. hours and MWh requirements. If these requirements are at a level likely to be met by DSR or DG/batteries, these sites were judged to be mitigated by flexibility services in our load plan. Otherwise, our load plan includes the cost of reinforcement using asset solutions to provide the forecast network capacity requirement.

For HV and LV networks we have followed a different approach for assessing where flexibility services may be applied to defer asset based solutions. Due to the lack of visibility of continuous power flows downstream of primary substations, we have used forecasts of utilisation across our whole HV and LV network from our Future Capacity Headroom (FCH) model. We have assumed that flexibility services can be an alternative to conventional reinforcement for secondary network assets where the firm capacity is only expected to exceed the firm capacity slightly. In these cases the magnitude of the necessary flexibility services (MW) and the duration of the needs (MWh) are lower, reducing the risk for domestic and small non-domestic customers not being available to provide the required flexibility capacity.

The assumptions we have made to quantify the number of HV and LV assets where load related interventions are required to provide additional capacity can be summarised as follows:

- analysis of distribution substations excludes pole mounted transformers (supplying less than 5% of customers) because they mainly supply remote rural customers and there is an increased risk of non-provision of flexibility services due to the very low customer population. For the very same reasons, only transformers greater than 200kVA with 10 customers or more have been considered for distribution substations with ground mounted transformers,
- overlaps with RIIO-ED2 asset replacement schemes were considered to further reduce flexibility service potential by 10%,
- flexibility services were only considered suitable for mitigating the overloads of only LV feeders and distribution substations that exceed capacity by up to 5kVA and HV feeders that exceed capacity by up to 100kVA. This approach allows even limited numbers of domestic customers to provide the required flexibility services for LV feeders and distribution substations, whereas for HV feeders small non-domestic customers can also provide services.
- we have assumed 50% availability of flexibility services from our customers and service providers across sites that comply with the above-mentioned requirements. This is a high level assumption that sufficient flexibility will not be available from providers across half of the sites we have identified requiring additional capacity.

6.2.2 Cost assessment of flexibility services and efficiency tenders

The flexibility or procured efficiency costs across the primary and secondary network sites where conventional reinforcement can be deferred have been assessed using the same methodology across all voltage levels. We have adopted an initial high-level approach in the absence of specific contracted costs on the understanding that market responses will inform the actual values to be evaluated using the Common Evaluation Methodology Tool in period. At this stage, using Ofgem's RIIO-ED2 CBA template we have balanced the conventional reinforcement cost assuming that this expenditure takes place in the beginning of the RIIO-ED2 with the option where constant per annum payment for flexibility services can postpone this expenditure to the middle of the next price control period, i.e. third year of RIIO-ED3. The balance of costs between the two options has been assessed based on whole life Net Present Value (NPV) results of the CBA.

By doing that we have estimated that up to 3.08% of the capital asset cost of conventional reinforcement can be spent per year during RIIO-ED2 for flexibility services or efficiency measures and this will result in lower whole life NPV than the corresponding reinforcement option.

To further identify the current level of flexibility available on the network and obtain information on how much flexibility could potentially be available in the future, an Expression of Interest (EoI) was issued in November 2020. This EoI detailed all our EHV requirements over the RIIO-ED2 period and a high-level estimate of up to 200 HV and LV requirements each year.

The responses of this EoI can be summarised as follows:

- 50% of respondents were owners or operators of LV assets, with 71% of proposed assets being part of an aggregated portfolio. This demonstrates the growing interest in LV flexibility markets within the North West which will be unlocked through advancements in network visibility from our LV network monitoring initiatives and the smart meter roll out.
- 67% of respondents were anticipating connecting to our network in the near future. In response to feedback we have maintained visibility of these requirements on our website so as to provide sufficient time for potential providers to develop these resources.
- other feedback included conflicting stakeholder opinions regarding procurement timescales from a day to up to two years ahead and preferred contract lengths from 1 to 25 years. This will be further explored and flexibility service products will be tailored to meet these requirements once liquidity is established within the market.

Our approach to procuring flexibility will continue to evolve in line with best practice as identified by the industry and through stakeholder engagement. As highlighted in our DSO Transition Plan, we also intend to put energy efficiency tenders that incentivise our customers to reduce consumption during times of peak load and avoid reinforcement. In period, cost benefit analysis using the Common Evaluation Methodology Tool or our enhanced Real Options Cost Benefit Analysis (ROCBA) tool shall ensure that flexibility services are employed where they are the most economical solution.

6.3 EHV network development

6.3.1 EHV load related interventions

High level reinforcement solutions for all identified thermal and fault level issues are developed via desktop exercises for individual named schemes. These solutions consider the overall system performance and the status of neighbouring parts of the network to ensure efficient and economic development of the network. Through our extensive optioneering, we develop a range of solutions to explore the capacity and benefits of alternative approaches. Typical solutions include:

- Reconfiguration of networks to redistribute load,
- Installation of interconnecting circuits to transfer power flows to less loaded parts of the network,
- Use of flexibility services and energy efficiency,
- Installation of additional assets,
- Replacement of equipment with greater ratings and overlay of circuits to increase capacity, and
- Other innovative solutions.

Use of power system analysis software IPSA enables us to develop whole systems solutions which can ensure that targeted and focused investment is made, reducing the possibility of investment leading to stranded assets. The range of solutions can be developed further before being subjected to a Cost Benefit Analysis (CBA) to determine the best value for money solution.

Further work is also carried out to cross reference load related programmes of work with the condition-based asset replacement programme. This ensures that all possible synergies from efficient planning to phasing and timing of interrelated works can be captured. Carrying out planning in this co-ordinated manner can lead to efficient resolution of network issues and can maximise investment benefits.

6.3.2 EHV fault level interventions

Fault level management is a critical network safety factor examined by our network impact assessments. When exceedances are identified, planned interventions traditionally take the form of making replacements with higher rated equipment but could also be a non-traditional innovation solution which does not require the switchgear to be replaced. This could be network rearrangement to lower fault level or it could be the implementation of an innovation project such as Respond[11]. Selected solutions are based on proven techniques which we consider to be deliverable solutions within the RIIO-ED2 period based on acceptable equipment outage, consents and acquisition risk. We currently view that some alternate technology solutions, such as fault current limiters, will not be economically viable at EHV in the RIIO-ED2 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, and
- The switchgear where fault level issues typically occur is often towards the end of its operating life and will require replacement on health grounds before the end of RIIO-ED2.

We will monitor ongoing smart technology developments and where possible incorporate these into our delivery plan.

6.4 HV and LV network interventions

Whilst our 132kV and 33kV reinforcement programme is made up of several named discrete projects, our LV and HV programme requires a larger number of smaller interventions to facilitate the transition to Net Zero carbon delivered by the increased deployment of LCTs.

The nature of the new LCTs that we anticipate will be connected during RIIO-ED2 will create issues not previously seen in any significant volume on the secondary (HV and LV) distribution network, for example power quality and maintaining statutory voltage levels. These considerations have been included in our modelling.

6.4.1 HV and LV load related reinforcement

As part of the transition to Net Zero carbon emissions, the electrification of transport and heating is expected to increase network loading levels from the connection point of residential customers on the LV network up to all above voltage levels. Following our impact analysis for identifying thermal stresses, unacceptable voltages and harmonic distortion issues in the HV and LV network, we adopt a

[11] https://www.enwl.co.uk/respond

“Flexibility First” approach where conventional reinforcement is avoided or postponed where we can release the required network capacity through flexibility and increase savings.

In cases where the required network capacity cannot be provided by flexibility services or energy efficiency, we undertake a step-by-step optimisation process to identify the most cost efficient and risk averse solutions. This subsection demonstrates how the adopted optimisation process works for conventional reinforcement in typical HV and LV networks. The applied optimisation has resulted in the selection of the minimum cost interventions that are correlated with the future volumes of LCTs and can mitigate the expected network issues.

Fig. 31 to Fig. 34 show how the optimisation process works for a typical underground LV network. As shown in Fig. 31, our first step (step I) when there is a low uptake of EVs charging via home chargers connected to the local LV feeder is to use monitoring data to better understand which LV networks will require reinforcement.

The use of monitoring data is a first action that will allow us avoid stranded assets in our LV networks where actual loading and harmonic distortion levels are below the predicted levels. It should be highlighted that even though the use of smart meter data is a low-cost option for thermal and voltage issues on symmetrically loaded LV networks, importantly smart meters cannot measure the unbalances and earth return currents through the neutral conductors. Measurement of unbalances and neutral conductor loading are critical to identify where capacity is exceeded in our LV networks. Therefore, as described in the associated EJP on our LV monitoring programme, we propose to use the PreSense system. This is a low-cost monitoring system for all phases and the neutral conductor that provides us with the necessary visibility of the HV (downstream of the feeders) and LV network loading to target when and where interventions are required to avoid both the risks of overloaded and stranded assets.

Additionally, smart meter data does not include information on levels of harmonic distortion in our LV networks. The proposed PreSense LV monitoring system allows the measurement of LV harmonics for ground mounted substations at the head of feeder as shown in Fig. 31. Based on our approach described above, an LV harmonics monitoring system is required when our forecasts per LV feeder exceed 43 EVs for urban networks and 15 EVs for rural networks (ie, 10% probability of failure/non-compliance with harmonic limits). This analysis has allowed us to quantify the requirements for pole mounted transformers; and quantify the cost savings for ground mounted substations where harmonic distortion can be measured by the PreSense LV monitoring system.

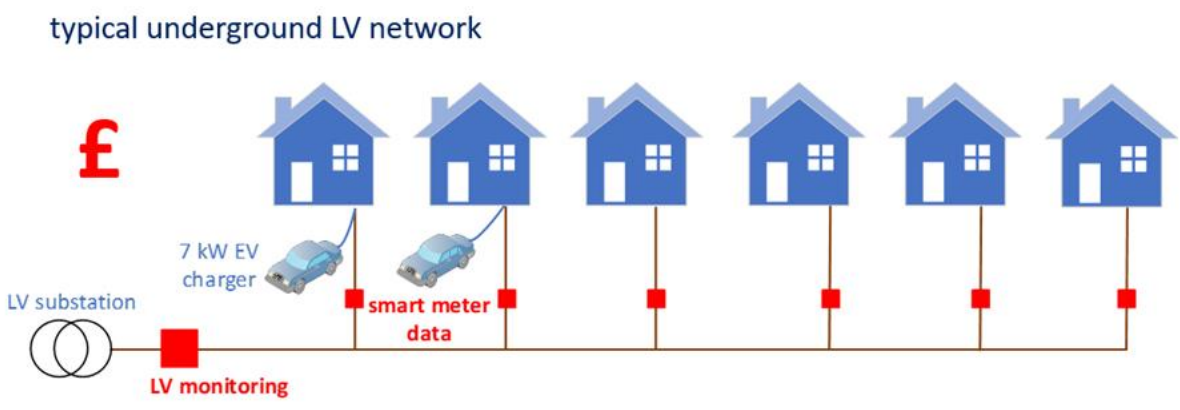


Fig. 31. Optimisation of the intervention selection process. Step I: low LCT uptake – installation of LV monitoring

In step II of our process, a medium LCT uptake along an LV feeder supplying residential customers is expected to result in a marginal excess load above the available network capacity. In the absence of flexibility services to provide the necessary capacity, the most cost efficient solutions that can increase the network capacity to secure the supply of this marginal excess load include cable overlays, cables upgrades and splitting the LV feeder, as shown in Fig. 32.

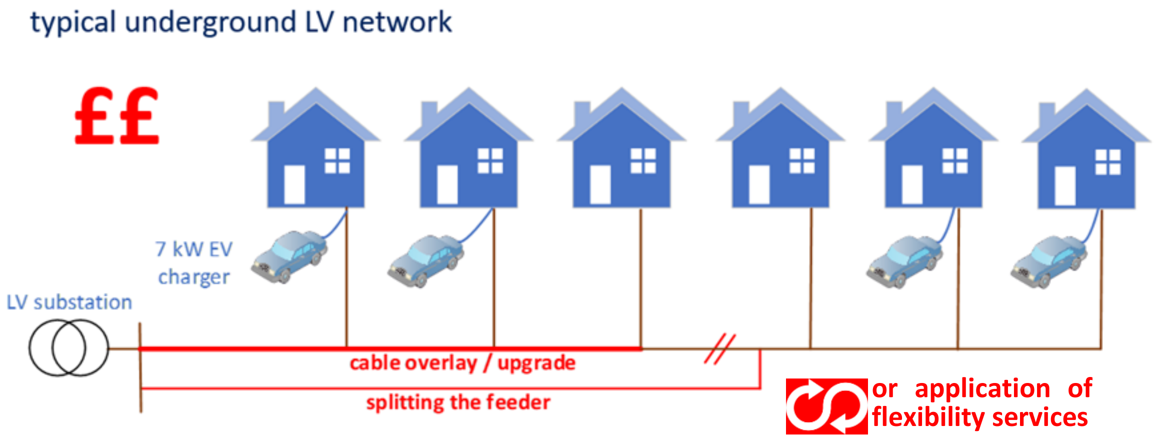


Fig. 32. Optimisation of the intervention selection process. Step II: medium LCT uptake – circuit overlap and split feeder or use of flexibility services

In step III of our process, a high LCT uptake along an LV feeder supplying residential customers can result in further exceeding thermal limits and also exceeding statutory voltage limits. In this case network interventions are required to provide more capacity headroom in terms of tackling both the thermal and voltage issues. Asset based solutions would only be used where flexibility services are not a valid option. As shown in Fig. 33, cost efficient and risk averse solutions in this case can include splitting the feeder in more sections and upgrading the LV substation transformer to tackle both thermal and voltage issues, as well as the installation of an on load tap changer (OLTC).

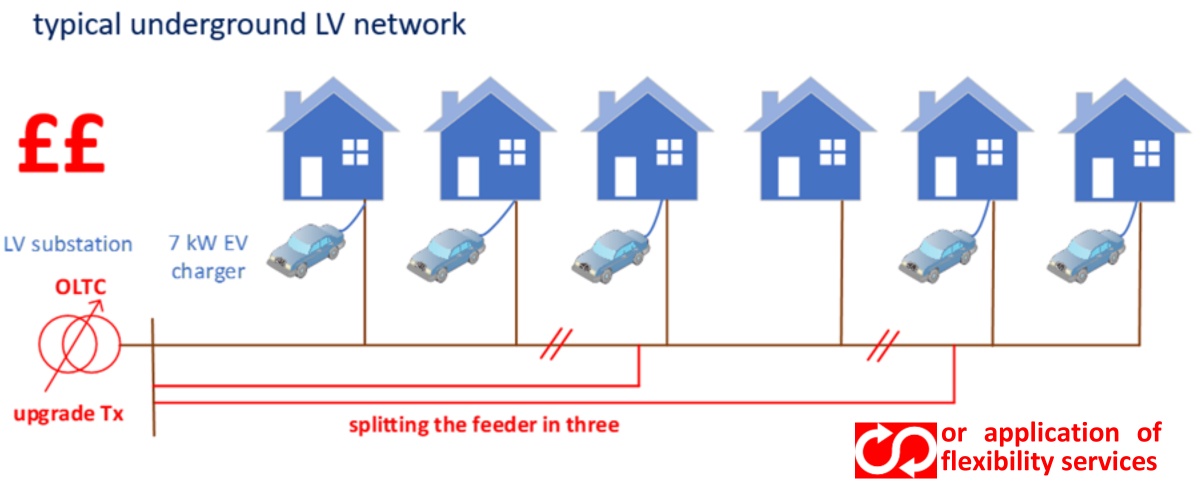


Fig. 33. Optimisation of the intervention selection process. Step III: high LCT uptake – multiple feeder splits and use of larger transformer with an on load tap changer

In the last step (step IV) of our process, a very high LCT uptake along an LV feeder supplying residential customers can pose the highest possible challenges to tackle the associated thermal, voltage and harmonic distortion impacts. To meet the significant demand growth in this case, a combination of interventions is required to significantly increase network capacity. As shown in Fig. 34, the required interventions include the ones in step III and can also consider the installation of new LV substation and/or new transformer on existing site with new LV board, LV feeders and link boxes. Filters may also need to be installed at the head of LV feeders to reduce harmonic distortion.

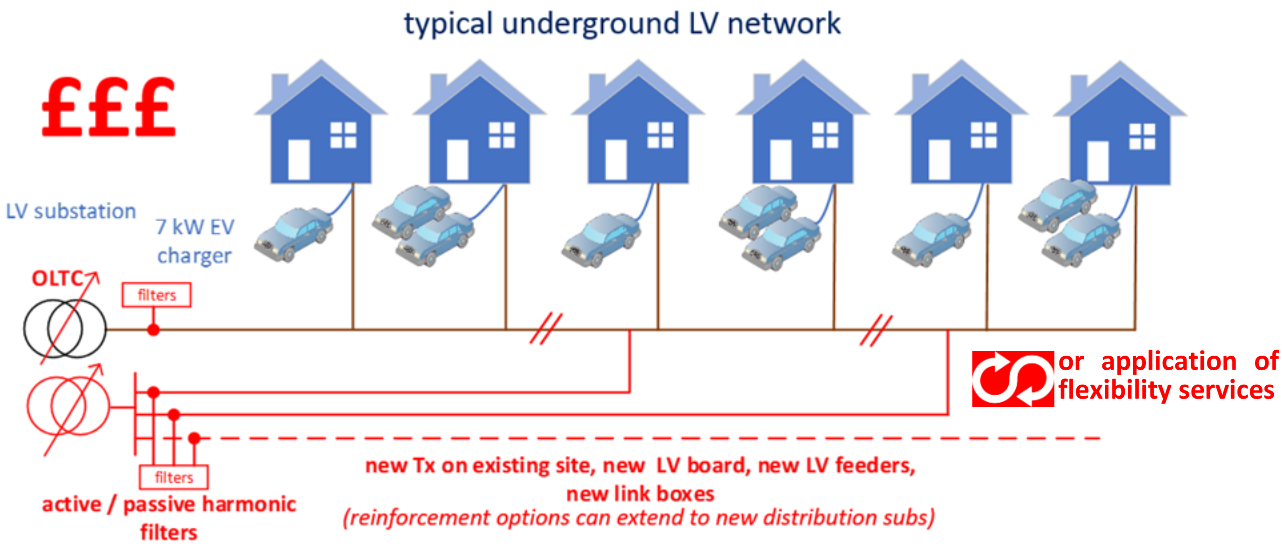


Fig. 34. Optimisation of the intervention selection process. Step IV: very high LCT uptake – installation of additional secondary substation

The same principles on the optimisation process, but with some modifications, apply for rural overhead LV networks. These networks are different from the underground networks that supply the majority of our customers. Typically, a limited number of customers are supplied per LV substation on rural overhead networks and the associated lengths of the HV and LV circuits are longer. Even a low number of LCTs can have thermal and/or voltage impacts that result in capacities and network limits being exceeded. Although the number of customers may be lower than urban situations, we would still adopt our Flexibility First approach to determine whether this option is available to resolve the network issue. Otherwise, step II of the process described above can be modified to consider a simple and cost-efficient LV overhead line upgrade, as shown in Fig. 35.

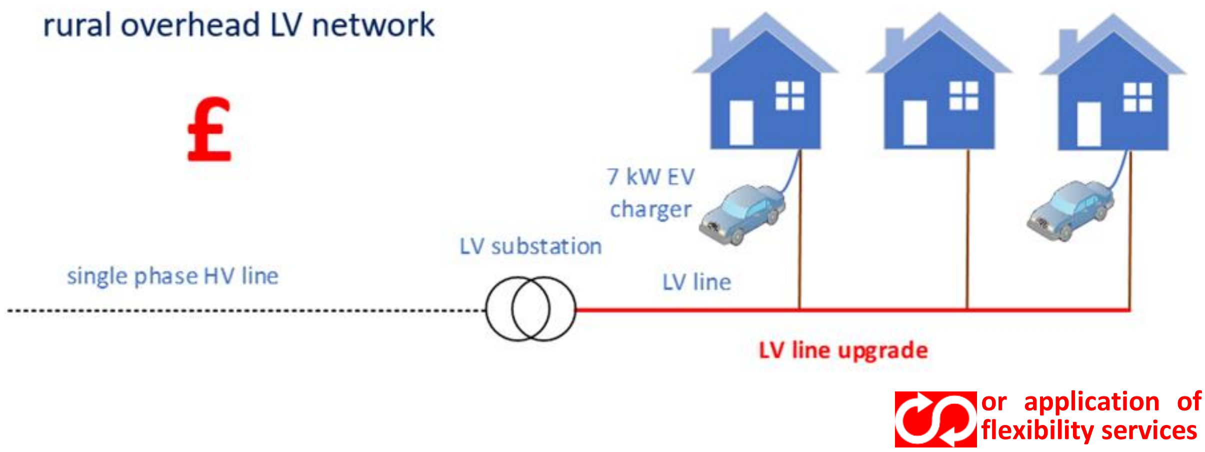


Fig. 35. Optimisation of the intervention selection process. Interventions for rural overhead HV and LV network with low/medium EV uptakes

Higher LCT uptakes can modify steps III and IV for rural overhead networks, due to the fact that dedicated HV overhead lines could be used to supply a limited number of residential customers via low ratings transformers and LV circuits as shown in Fig. 36. The effects from more LCTs connected to these networks will require the uprating of the capacity of the whole supply, including the HV overhead line all the way down to the customers' connection points requiring replacement of the LV substation transformer and upgrade of LV circuits. These interventions can tackle both thermal and voltage issues, whereas OLTCs can be also used as an additional measure to maintain statutory voltage levels.

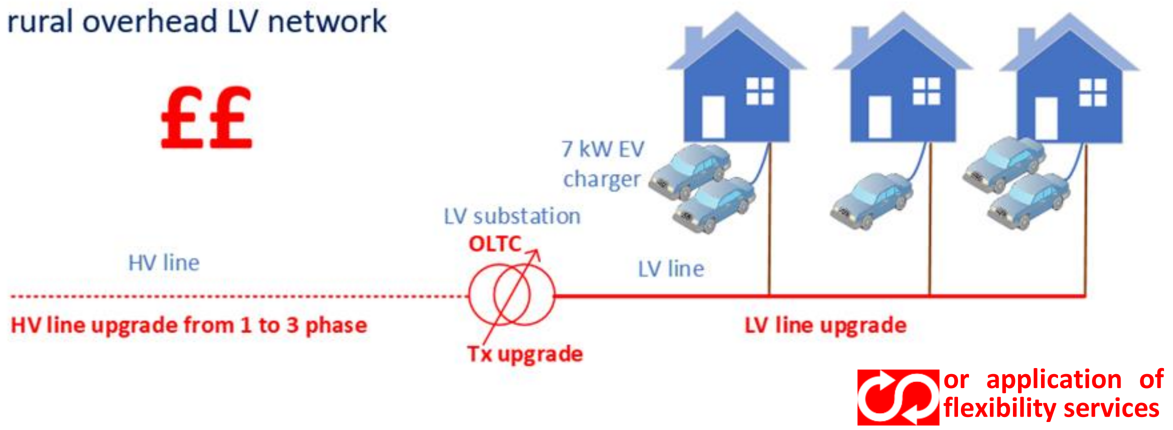


Fig. 36. Optimisation of the intervention selection process. Interventions for rural overhead HV and LV network with higher EV uptakes

Monitoring data is a key component from the very first step of optimising HV and LV reinforcements. As described, measurements of loading across all phases and the neutral conductors are required on large parts of the networks where higher LCT uptakes could cause thermal, voltage and harmonic distortion issues. As described in section 3, our proposed PreSense LV monitoring programme is able to measure all these for 95% of customers by the end of RIIO-ED2 supplied by ground mounted transformer secondary substations and provide additional benefits, such as the "manage and connect" implementation to release capacity for LCTs.

Smart meter data will expand visibility of loading and importantly voltage compliance down to the end customers to support the monitoring data measured at the heads of LV feeders using the PreSense LV monitoring system. The wider benefits to our HV and LV reinforcement programme from the use of smart meter and LV feeder measurement data include abilities:

- to determine current utilisation of the network,
- to determine available capacity for new/additional load and generation connections,
- to determine load factors so that appropriate equipment ratings can be used,
- to identify possible opportunities for flexibility services, and
- to improve our understanding of domestic and industrial/commercial load profiles.

The smart meter data will be gathered from the Data Communications Company (DCC). Connectivity data from our internal GIS and Network Management System (NMS) systems can show all MPANs connected to an LV feeder, secondary substation and HV feeders. The secondary substations will feed via a web interface (API) into the Smart Service Gateway (SSG), which is our corporate system that is used to communicate with all devices in the network. The SSG will then request to pull from the DCC the consumption and voltage quality data (ie, alerts for under/over-voltages) from the associated smart meters for all MPANs on the specified secondary substations or associated LV feeders.

Before being stored in our corporate system, the smart meter consumption data will need to be anonymised and aggregated. Similarly, the voltage quality data will be anonymised and processed to flag over/under-voltage issues per LV feeder / secondary substation. The anonymisation of the smart meter data will be in line with our Data Privacy Impact Assessment (DPIA) approved by Ofgem.

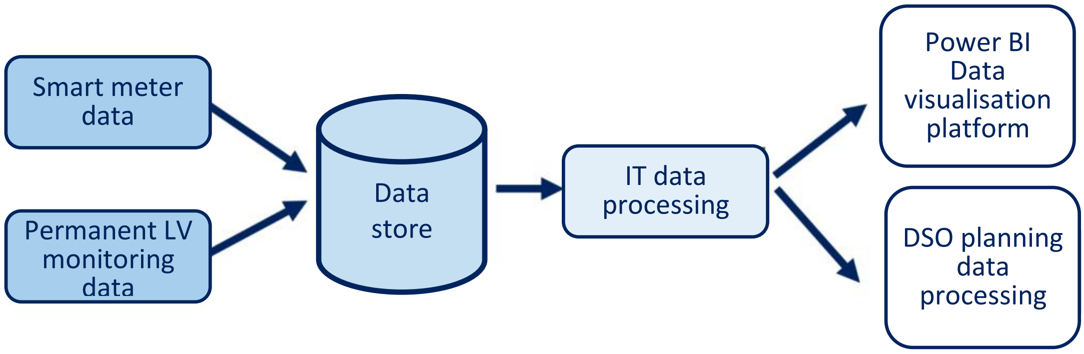


Fig. 37. Process of utilising smart meter data as part of the optimisation process for interventions in HV and LV networks to tackle thermal and voltage issues

All LV feeder, secondary substations and HV feeders have unique alphanumeric references. This will allow the GIS and NMS data on thermal network capacity to be compared against aggregated consumption data from the smart meters for LV feeders, secondary substations and HV feeders. Voltage quality data will be analysed to identify non-compliances with the Electricity Safety, Quality and Continuity Regulations (ESQCR).

As shown in Fig. 37, a central Data Store repository will be used to host the smart meter and PRESense data. The network planning team, within the new DSO directorate will provide specifications for an IT pre-processing of the data including aggregation of half-hourly through year consumption data at different levels from LV feeder sections up to HV feeders. The processed and unprocessed monitoring data will be visualised using Microsoft Power BI platform.

This data will be also available to the network planning team in simple formats (eg, csv/txt files or using scripting from databases). This way the monitoring data can feed into the working tools of engineers and analysts to understand network utilisation across all voltages, enhance forecasts and facilitate flexible services at lower voltages. IT support will be also provided to increase the computational power for automation of big data analytics using measurements across the whole network, ie utilise multiple machines to facilitate parallel processing capabilities.

6.4.2 HV fault level reinforcement

The equipment that forms the electricity distribution network must 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 (ie they have 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 constrains 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-ED2 we are proposing to continue intervention on 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. Proactive replacement of this equipment is necessary to facilitate the prompt connection of LCTs by customers because it typically has long lead times of up to two years.

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 to avoid double counting.

HV networks in the urban areas in our region predominantly operate at 6.6kV level rather than 11kV which is more commonly found in the rest of our area. This is a legacy from the original network installation. A fault rating of a proportion of the switchgear in these areas is below the present UK design standard of 21.9kA and often presents a barrier to the connection of low carbon technologies (LCTs). To remove this potential barrier, we propose to continue with the removal of this type of switchgear from our network over RIIO-ED2 to coincide with the expected profile of LCT adoption.

The criteria used to identify and prioritise 6.6kV 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, and
- 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.

The optimal intervention for the particular issue we face with HV Ring Main Unit ratings given the asset age and condition is to replace with modern equipment.

6.4.3 Service interventions

An emerging need in ED2 driven by Net Zero aims and the decarbonisation of heat and transport is the need to manage constraints at domestic properties. Constraints can be caused by a range of issues at the service point:

- Being connected to the distribution network via a looped service
- Having a fuse rating which is insufficient for their demand needs
- Having a cut-out which is unable to accommodate a new fuse
- Having a service cable which is an insufficient size to meet their demand needs

For many years these characteristics have existed, causing no issues for customers until they wish to significantly change their demand and use requirements, at which point intervention by the DNO is required. As we enter a world where customer demand and network usage are starting to change as a result of the uptake of electric vehicles and heat pumps, each of these service constraints may prevent a customer connecting and using their LCT in the manner they wish and therefore need to be addressed. It is important to remove these risks and ensure that the electrical network is not a barrier to the uptake of Low Carbon Technologies (LCTs) necessary to meet the national Net Zero target.

Taking each in turn:

<u>Looped Services</u>
Historically, looped services were installed as an economic and efficient way of connecting new properties mainly in the 1960’s and 70’s and were commonly used for new terraced houses and new housing estates. This was a safe and efficient way of constructing the network at that time and have provided satisfactory performance for many decades based on average domestic demand and network usage. Further detail on how we propose to unloop services is given in section 6.4.4.

<u>Enhancing the fuse rating</u>
In the case of an enquiry about installation of an LCT, the installer provides the current fuse rating and total maximum demand, including the LCT. If the maximum demand exceeds the fuse rating then we will attend site to install a fuse with a greater rating.

Upgrading the cut-out

There are certain types of cut-outs that are unable to accept a fuse upgrade. In these instances, the old cut-out needs to be removed and replaced with a new cut-out which can accept the larger fuse size. Work to do this can be done either “live” or “dead” depending on circumstances. We have some instances where the operative is able to complete the change whilst keeping the incoming service cable “live”. Depending on the type of cut-out, the cable may need to be made “dead” which would involve excavation to complete a safety cut on the existing service cable to temporarily remove power to make the property dead, allowing us to safely remove the old cut-out and install the new upgraded one. The existing service cable would then be reconnected to make “live” once again.

Uprating the service cable

Every service cable has a maximum current rating based on the size of the conductor. We will need to install a new larger service cable if a property’s existing service cable is inappropriately rated for the new demand level including the LCT. An excavation will be required to install the new service cable, referred to as service cable uprates. The same approach is applicable to overhead service connections often referred to as “murals”.

6.4.4 Unlooping of service cables

Some older properties in our region, 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 as shown on the left hand side of Fig. 38. This means that the electrical demand of a number of properties is supplied from a single service cable rather than a service cable per property connected to the mains cable. In our licence area there are currently around half a million domestic connections supplied by looped services.

Looping of service cables was a safe option for the historical domestic demand levels and reduced installation costs when providing our customers with an electricity supply. In the housing developments in 1960s through to the mid-1990s the looping of services was standard practice for all housing types, with up to four loops supplied by one service.

However, LCT devices such as electric vehicle chargers are expected to increase domestic demand levels significantly. Although smart solutions and targeting of interventions using monitoring data (eg, from smart meters) can apply at higher voltage levels, the non-diversified effects of everyday activities between a couple of domestic customers (eg, charging EVs at the same time or charging an EV at the time that another customer is heating water) can exceed the rated capacity of looped service cables. This poses potential safety risks as there is the possibility of overheating service cables that can result in cable burning close to houses.

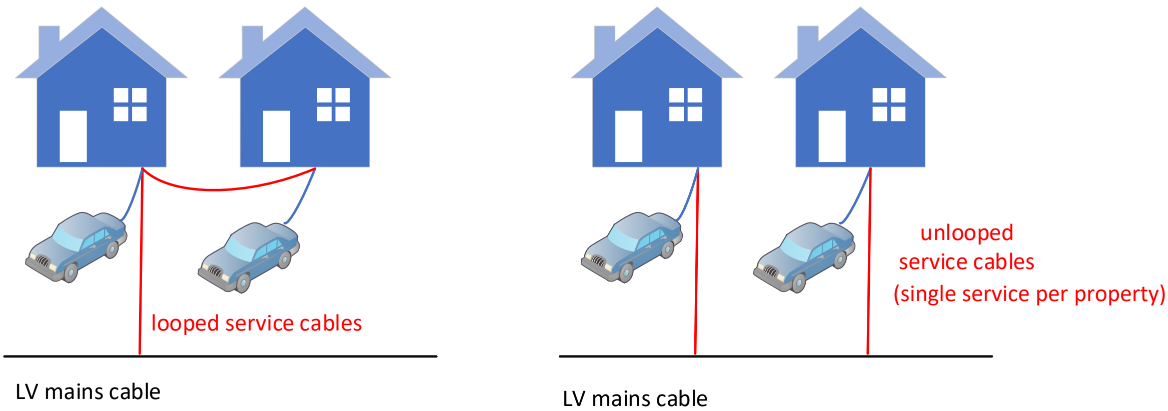


Fig. 38. Looped service cable supplying multiple domestic customers (left) and the unlooping intervention (right)

Therefore, we are proposing to address this issue by intervening on looped services and providing discrete services to each property as shown in the right-hand side of Fig. 38. This will facilitate the uptake of LCTs and especially the connection of domestic electric vehicle chargers and heat pumps. A dedicated EJP (LRE EJP 8) includes more information on the proposed unlooping programme including the underlying methodology, the volumes, costs, optioneering and delivery.

Flexibility services are not an appropriate solution to the safety risks due to looped services when customers connect LCTs because there is no competitive market. Only the customers connected to the looped service can solve the constraint. They would need to permanently limit the amount of electricity they use without our intervention to resolve the issue of the looped service.

6.5 Innovative and flexible solutions

Apart from traditional asset solutions to tackle load related issues, innovative and flexible solutions (including energy efficiency tenders) can be the alternatives that allow us to reduce load related expenditure. Using them we can also mitigate any risks associated with excess loads and lead times of asset solutions.

Innovation benefits are derived in different parts of our business and delivered directly to our customers, eg in the form of reduced energy bills if they consume less energy as a result of voltage control. Our CLASS, Quest, Celsius, C_2C and Enhanced Voltage Control innovation projects can support solutions for thermal issues, whereas our Respond and Investigation of Switchgear Ratings projects can do it for fault related issues. It should be noted that some of the innovative approaches are already business as usual and integrated into the LRE plan.

Half-hourly through year capacity balancing requirements across our EHV network can be identified using the detailed assessments supported by our ATLAS forecasting methodology. This allows us to define detailed flexibility requirements, such as number of days per month, energy requirements per day and capacity requirements per season to procure the required capacity of flexibility services only when they are needed.

The identified flexibility service requirements are then issued to the market via numerous channels. At this point we undertake extensive engagement to promote these requirements and facilitate participation within the market. EHV requirements are initially identified on an annual basis in alignment with the latest DFES, however, where data requires further monitoring to capture ongoing demand growth or validation, the publication of these requirements may be delayed while this information is confirmed. Bi-annual reviews of connections activity outside of the DFES process are also be undertaken to identify regions with high levels of connections activity which may trigger reinforcement otherwise not identified through the aforementioned report. Flexibility can then be used to mitigate risks associated with the potential that actual demand growth associated with the connections pipeline materialises beyond the expected based on historical performance that informs the confidence factors used in the forecasts (see section 4 on ATLAS methodology).

Following closure of each flexibility tender, bids are assessed to determine their technical and economical compliance and a cost benefit analysis undertaken comparing the proposed flexibility to all alternative solutions.

Even though primary substations are currently the last point of monitoring and this limits our ability to procure flexibility services to tackle load related issues at lower voltages, installation of monitoring and the use of aggregated smart meter data in the final years of the RIIO-ED1 period will increase our visibility in HV and LV networks. This data will provide increased visibility of our HV and LV networks, allowing us to understand utilisation of the network and define our requirements for flexibility services at these lower voltage levels. With approximately 35,000 secondary substations located across the North West, it is estimated that we will have up to 200 opportunities available each year, facilitating the growth of residential flexibility and energy efficiency markets and fulfilling our role as a neutral market facilitator.

We will continue to act in the best interest of our customers, and to procure flexibility services and energy efficiency where it is economic and efficient to do so.

6.6 Decision making

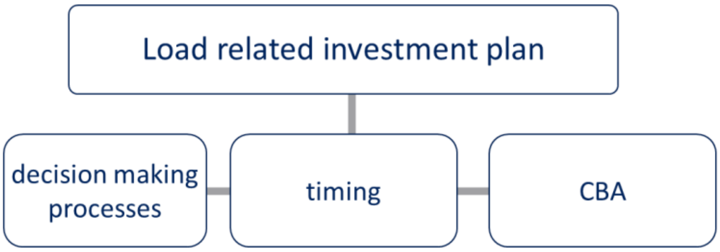


Fig. 39. Components considered in the solutions selection of the load related investment plan.

To select the proposed solutions of our RIIO-ED2 load related investment plan, the full range of solutions that has been identified in the optioneering process are compared. Apart from an element of optimisation in terms of a quantitative minimisation of costs and risks among solutions, an element of judgement is applied in our decision making to ensure that multiple vectors are taken into consideration to allow us to decide after seeing the "full picture". To do that we need to consider practicalities and other qualitative factors to complement the quantitative analysis.

We follow Ofgem's RIIO-ED2 CBA guidance when undertaking cost benefit analysis to inform our decision-making processes and identify optimal solutions. More specifically:

- for all proposed EHV asset solutions the Common Evaluation Methodology (CEM) tool developed in Open Networks and incorporating Ofgem's RIIO-ED2 CBA has been used to compare them with flexibility and other alternative options, and
- for major programmes such as the LV monitoring and unlooping programmes, the proposed solutions have been compared with alternatives using Ofgem's RIIO-ED2 CBA.

The CBAs consider the "do nothing" and deferral of interventions, eg using flexibility services as an interim measure. Our RIIO-ED2 LV monitoring programme will facilitate the expansion of flexibility services to the whole of our network. This will allow us to use flexibility services to address the risk of stranded assets across all voltages and delay greater network investment until demand growth materialises. This will also allow us to mitigate any risks for excess load in the opposite case when demand growth is accelerated and there is a long lead time associated with asset-based interventions.

For the remaining parts of the HV and LV load related investment programme there is no formally applied use of CBA applied at this stage. Like the approach adopted for the RIIO-ED1 plan, a programme of a large number of low cost interventions is proposed. Therefore, the decisions for the proposed asset solutions have been based on the network optimisation process described in section 2.1. This four-step process that allows us to mitigate the risks of exceeding network capacity by deploying the minimum cost intervention depending on the levels of demand growth forecasted and the associated network impacts.

As highlighted in Ofgem's RIIO-ED2 guidance, the timing of interventions is critical and where sensible, interventions can be brought forward with robust reasoning. It should be noted that no interventions have been brought forward following our RIIO-ED2 methodology for load related investment. However, our DFES includes developments with strong evidence from LA and UK government backing and secured funding to ensure a holistic approach and avoid piecemeal network development.

Our load related investment plan is our best view of what we expect will be required during the RIIO-ED2 period, but this is based on assessments made in advance of those on which development decisions are normally made. We continually review capacity on our network and the need for interventions to increase capacity by checking the latest actual conditions on our network and forecasts. Investment plans are scrutinised as part of this process to assess whether they still provide the optimal way forward and will deliver the necessary benefits at the required time. This way we ensure that our plans flex to reflect the changing energy landscape and network requirements. As with all capacity shortfalls, the market is tested at that time to determine if a flexibility service can be obtained to provide a solution and the associated cost, so that a fair comprehensive cost benefit analysis can be used to compare with more traditional asset-based interventions to establish the most efficient solution to be taken forward. In period, cost benefit analysis using the Common Evaluation Methodology Tool or our enhanced Real Options Cost Benefit Analysis (ROCBA) tool shall ensure that flexibility services are employed where they are the most economical solution.

7 GLOSSARY

Acronym	Definition
Access SCR	Access and Forward Looking Charges Significant Code Review - the Ofgem led review of the distribution connection and use of charging arrangements
ATLAS	Architecture of Tools for Load Scenarios
BESS	Battery Energy Storage System
BSP	Bulk Supply Point substation, typically 132/33kV
CBA	Cost Benefit Analysis
CCC	Committee on Climate Change
CO	Central Outlook scenario from ENWL DFES 2020
COP	Heat pump coefficient of performance
CT	Consumer Transformation scenario from FES/DFES 2020
DFES	Distribution Future Electricity Scenarios
DNO	Distribution Network Operator
DRL	Devolved Regional and Local
DSO	Distribution System Operation
DUoS	Distribution Use of System
EHV	Extra High Voltage, typically 132kV and 33kV
EJP	Engineering Justification Paper
ENA	Energy Networks Association
ENWL	Electricity North West Ltd
EoI	Expression of Interest
EREC	Engineering Recommendation
ESC	Energy Systems Catapult
ESO	Electricity System Operator
EV	Electric vehicle
FCH	Future Capacity Headroom model
FES	Future Energy Scenarios
FY	Financial year
GMSF	Greater Manchester Spatial Framework
GSP	Grid Supply Point substation, transmission-distribution interface, typically 400 or 275/132kV
HIF	Housing Infrastructure Fund
HP	heat pump
HV	High Voltage, typically 11kV and 6.6kV
LA	Local Authority
LAEP	Local Area Energy Plan
LEP	Local Enterprise Partnership
LRE / LRI	Load Related Expenditure / Load Related Investment
LTDS	Long Term Development Statement
LW	Leading the Way scenario from FES/DFES 2020
LV	Low Voltage, typically 0.4kV
NRSWA	New Roads and Street Works Act (1991)
NTCC	New Transmission Connection Charges
ON	ENA Open Networks project
Primary	Primary substation, typically 33/11 or 6.6kV
RIIO	Revenue=Incentives+Innovation+Outputs
SCR	Significant Code Review
Secondary	Secondary substation, typically 11 or 6.6/0.4kV
SIWG	Strategic Investment Working Group
SP	Steady Progression scenario – FES/DFES 2020

SSMD	Sector Specific Methodology Decision
SRF	Strategic Regeneration Framework
ST	System Transformation scenario – FES/DFES 2020
ToU	Time of Use (for tariffs)
TUoS	Transmission Use of System
WS1b P2	Open Networks Workstream 1b Product 2 – Whole System FES